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Baseline Techno-Economic Assessment of Small-Scale Carbon Capture for Industrial and Power Systems

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IEA GREENHOUSE GAS R&D PROGRAMME

Disclaimer

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About IEAGHG

Leading the way to net zero with advanced CCS research. *We pioneer technology to accelerate project development & deployment.*

We are at the forefront of cutting-edge carbon, capture and storage (CCS) research. We advance technology that reduces carbon emissions and accelerates the deployment of CCS projects by improving processes, reducing costs, and overcoming barriers. Our authoritative research is peer-reviewed and widely used by governments and industry worldwide. As CCS technology specialists, we regularly input to organisations such as the IPCC and UNFCCC, contributing to the global net-zero transition.

About the IEA

The International Energy Agency (IEA), an autonomous agency, was established in November 1974. Its mandate is to promote energy security amongst its member countries through collective response to disruptions in oil supply, and provide authoritative research and analysis on ways to ensure reliable, affordable and clean energy. The IEA Technology Collaboration Programmes (TCPs) facilitate international collaboration on energy related topics.

BASELINE TECHNO-ECONOMIC ASSESSMENT OF SMALL-SCALE CARBON CAPTURE FOR INDUSTRIAL AND POWER SYSTEMS

This study, undertaken on behalf of IEAGHG by Element Energy (now a part of ERM), explores the role of CCS in decarbonising small-scale industry and power generation applications. While relatively under investigated compared to their larger scale counterparts, reaching net zero will be dependent on successfully addressing the emissions from small-scale facilities. The findings from the study will be of interest to the broader energy community but, in particular, should benefit project developers, the finance community and policymakers.

Key Messages

- A significant share of CO_2 emissions from industry and power generation is emitted from small-scale applications, defined for this study as:
  - Industry sites emitting up to 100,000 t CO_2 annually from point sources.
  - Power generation plants with an unabated installed capacity of up to 100 MWe.
- As small-scale applications will also be required by governments to honour the net-zero CO_2 emissions pledge, technology developers are increasingly turning their attention to the capture of carbon from them.
- Until now, most analysis on the deployment of CCS on power and industrial applications has focused on large-scale plant, defined as plant with annual CO_2 emissions of several hundreds of thousands, if not millions, of tonnes. This reflects the dominant focus of technology developers on the larger applications that offer stronger economies of scale.
- While the cost advantages stemming from economies of scale remain valid, energy and climate imperatives coupled with technology progress and incentives to reduce CO_2 emissions may result in capture plant sizes that were once considered uneconomic to now offer more attractive prospects.
- The literature on carbon capture mostly focuses on large-scale applications. While there are many pilots and small-scale demonstration projects ongoing, a granular breakdown of performance and costs is often not published. Moreover, there is a lack of publicly available data on the performance of many patented processes. This results in a scarcity of data on carbon capture from small-scale applications that makes a bottom-up analysis of the costs of such applications more challenging.
- To address this problem, four case studies of small-scale capture applications were explored in the analysis undertaken for this study:
  - Natural gas-fired combined-cycle gas turbine (CCGT);
  - Natural gas-fired co-generation (or combined heat and power (CHP));
  - Energy from waste (EfW); and
  - Lime kiln.

  In the case of the CCGT, its large-scale analogue was also explored for comparison.
- Based on available data, techno-economic assessments were performed and the following high-level metrics estimated:
  - The cost of carbon capture;
  - The cost of carbon avoidance; and
  - The impact on the cost of key products (e.g., lime) or outputs (e.g., electricity and heat).
- Findings showed that the relative share of capital expenditure in the total cost of a CO_2 capture facility increases as the capture plant is downscaled. Consequently, capture technologies that are best suited for large-scale capture are not necessarily those best suited for small-scale capture.

While amine-based post-combustion capture is the current benchmark capture technology due to its higher maturity, its capital-intensive nature makes it more costly to deploy at small scale.

- Emerging capture technologies that may be better suited for small-scale capture include:
  - Advanced chemical absorption. Alternatives to amines could lower both capital and operational costs.
  - Membrane separation. Membranes are modular by nature.
  - Molten carbonate fuel cells. MCFCs are potentially attractive due to their modularity and because their capture cost is decoupled from the heat supply strategy.
  - Cryogenic separation. Lower energy penalty and cost than competing technologies, plus liquid CO_2 can be produced ready for transportation.

  Further development and deployment will be necessary to reach a verdict on which capture technologies are most suitable each of the different applications.

- By taking advantage of mass manufacturing, modularisation and standardisation could potentially offset the loss of economies of scale for small-scale applications. Standardisation of capture units, however, would involve a trade-off between high performance and low manufacturing and engineering costs.

- Differences in operational modes of large- and small-scale plants influence the suitability of capture technologies. For instance, as processes typically found in smaller-scale industries normally operate at lower temperatures than their large-scale counterparts, less waste heat might be available for use in many small-scale capture plants. This confers an advantage to capture technologies powered by electricity or technologies where regeneration is possible using low-temperature heat.

- The analysis undertaken clearly demonstrates that higher levels of financial support are required to offset the higher relative costs of small-scale capture and stimulate investment. A combination of low energy costs, high carbon prices and additional policy support would encourage deployment of small-scale capture plant. Moreover, the following issues should be considered:
  - The lack of specific research, development and demonstration targeting small-scale plants results in evident gaps in the publicly available literature and a shortage of data.
  - The relative cost of CO_2 infrastructure is likely to be higher for small-scale applications as economies of scale for CO_2 transport would be lost and small-scale plants tend to be dispersed and away from anchor emitters.
  - Alternative decarbonisation strategies like electrification could have a stronger comparative advantage at smaller scales, especially if they are less capital-intensive.

- To address many of the challenges facing small-scale capture applications and to minimise the transition costs involved, tailored policies and incentives that target the higher relative cost of small-scale capture may be required, e.g., the scope and duration of existing incentives could be extended. Any such approach would need to achieve a balance between two different objectives:
  - The need for policy measures to encourage least cost abatement including uptake of low emissions technologies and practices (existing or new); and
  - The need for direct incentives for development and early deployment of new technologies to encourage market diffusion or uptake.

- It is instructive to note that several countries are introducing or have introduced incentives to encourage decarbonisation of their energy sectors, which may change (or have changed) the economic equation whereby some smaller-scale capture applications might now become (or have become) commercially viable. Geographic regions explored in the analysis undertaken for this study are the Netherlands, California and Texas in the United States, and China.

- In the absence of effective policies and incentives, the alternative would be to introduce mechanisms that better enable emitters to pass the additional costs on to consumers. Such a course of action might be particularly challenging to realise.

Background to the Study

Carbon capture, utilisation, and storage (CCUS) is widely recognised as a key part of the toolkit of solutions needed to reach net-zero greenhouse gas emissions. A significant share of CO_2 emissions from industry and power generation arises from smaller sites (as defined by their level of CO_2 emissions). Decarbonisation of such sites will be required to honour the net-zero pledge. Accordingly, technology developers are turning their attention to the growing demand for solutions to capture carbon from small-scale emitters.

Until now, most analysis on the deployment of carbon capture for power and industrial application has focused on large-scale sites with annual CO_2 emissions of several hundreds of thousands, if not millions, of tonnes. This reflects the dominant focus of technology developers on deploying solutions to tackle the larger emitters, most often rationalised by the fact that deploying CCUS on larger applications is considered to offer better economies of scale – economies of scale relating to both the capture plant and the transport and storage infrastructure. By the same token, CCUS units designed for smaller scale applications have very often been labelled “uneconomic”.

However, while the cost advantages stemming from economies of scale remain valid, energy and climate imperatives coupled with technology progress and incentives to reduce CO_2 emissions may result in plant sizes that were once considered uneconomic to now be commercially viable (or be approaching commercial viability). Also, considering the increased focus on relatively costly decarbonisation solutions such as direct air capture, carbon capture from small-scale emitters could hold the key to cost-effective decarbonisation, as well as presenting an opportunity for smaller sites to decarbonise.

Several countries are introducing or have introduced incentives to encourage decarbonisation of their energy sectors, which may change (or have changed) the economic equation whereby some smaller-scale capture applications might now become commercially viable (or have become commercially viable). Incentives may take the form of, e.g., tax credits, carbon pricing, carbon subsidies, direct grants, and/or emissions standards and regulations. Examples include the Inflation Reduction Act (IRA) in the United States, the California Low-Carbon Fuel Standard in California, and the European Trading Scheme (ETS) in the European Union.

While they may be challenged by economies of scale, smaller-scale capture systems may offer some advantages compared to larger systems. For example, smaller-scale systems would typically require less “total” capital investment, which could make access and availability to project financing and investment less of an issue. Additionally, many industrial facilities and “campus-style” facilities have small power generation units that provide electricity and, in some cases, heat as well, i.e., combined heat and power (CHP) plant, where CO_2 capture could offer a potential option for decarbonisation. The ‘hub’ approach to CCUS would, of course, benefit the economics of capture from smaller-scale systems. For remote applications (where the plant may not have access to ‘hub’ facilities), the smaller amount of CO_2 compared to larger projects could offer some potential cost savings at the storage site: less characterisation, less wells, etc. and possibly facilitate less complicated regulatory approval.

There are however knowledge gaps relating to small-scale capture applications. It is important to understand as fully as possible the techno-economics of capture on small-scale applications and the policy levers required to develop the market and enable technology uptake. As a step to bridge the knowledge gap, this study was commissioned to review publicly available literature and collect input from industry stakeholders and technology developers to:

- Review the evidence base for small-scale carbon capture.
- Evaluate the availability of technology solutions suitable for small-scale carbon capture, highlighting associated trends.
- Provide a techno-economic assessment of carbon capture from small-scale applications for power generation and industrial processes.
- Establish how existing policies and incentives could contribute to the economic viability of carbon capture from small-scale applications.

Through this study, policymakers will get a better sense of the cost of capture from smaller-scale sources and the types of incentives or inducements that would help or be needed to facilitate capture from them; financial investors and project developers will gain a better understanding of the technical status and opportunities for capture from small-scale systems; and technology developers will be able to identify potential R&D needs specific to small-scale carbon capture.

Scope of Work

A working definition of small-scale power and industrial applications for carbon capture was formulated for the purposes of this study based on analysis of data on CO_2 point sources from sectors of interest. This revealed qualitative differences between large- and small-scale power and industrial applications, as some industrial processes or power plant configurations can in fact only be found at large scales. For example, there are no small-scale oil refineries or small-scale integrated iron and steel sites. This analysis led to the selection of independent thresholds for defining what constitutes a small-scale capture application in the power generation and industry sectors:

- Power generation – plants with an unabated installed capacity of up to 100 MWe.
- Industry – sites emitting up to 100,000 t CO_2/year from point sources.

This study addresses the knowledge gaps relating to small-scale carbon capture applications and assesses four case studies in the industry and power generation sectors:

- Gas-fired power generation, with a focus on a natural gas-fired combined cycle gas turbine (CCGT);
- Natural gas-fired co-generation, or combined heat and power (CHP);
- Energy from waste (EfW);
- Lime kilns.

Considering that CCGT plants are found at both small-scale and large-scale, a comparison was made between a small-scale prototype and its large-scale analogue to better understand the cost implications of downscaling capture units.

Findings of the Study

Following a literature search, the relative lack of techno-economic data on small-scale capture applications underlined the overwhelming emphasis to-date on large-scale plant. Due to the general unavailability of data on small-scale applications, the capital cost of carbon capture at a small scale was estimated by scaling down relevant benchmarks for large-scale plants via a power law. This constituted a key limitation of the study that may only be addressed via the publishing of relevant cost data by technology and project developers.

Results showed a significant cost escalation when the size of the capture unit is scaled down. Figure 1 illustrates the negative correlation between the unit cost of capture and the scale of the emissions for the four case studies and their variations for amine-based post combustion capture. While the large-scale CCGT power plant shows the lowest cost of carbon capture ($44/t CO_2), the EfW plant and the lime kiln – the two case studies with the lowest level of unabated CO_2 emissions – show a much higher cost of capture, ranging from \$90/t CO_2 to \$103/t CO_2.

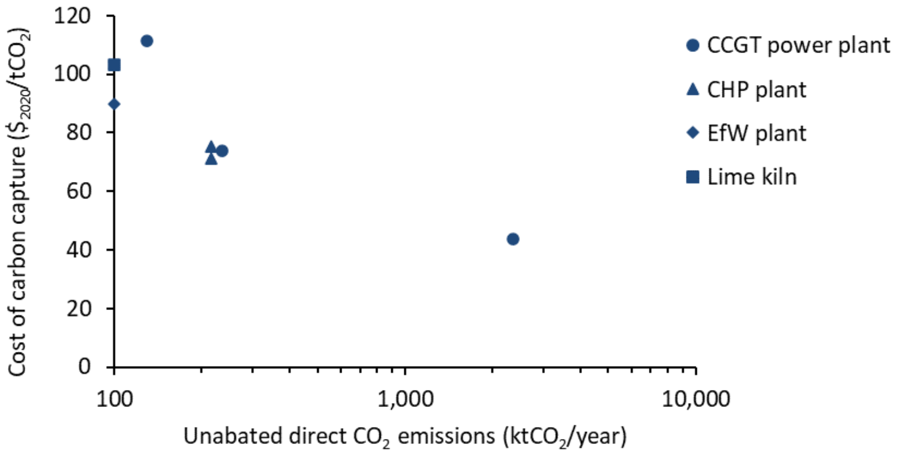

Figure 1: Cost of carbon capture on selected case studies

Efforts to lower the cost of small-scale capture should primarily target capital costs

Capital expenditure (CAPEX) increasingly becomes the dominant cost factor at smaller scales. As illustrated in Figure 2, CAPEX represents 37% of the levelised capture costs for a large-scale CCGT power plant but grows to 49% for its small-scale analogue. The capital cost component also grows as capacity factors reduce; for a small-scale CCGT power plant operating at part-load, capital costs account for 59% of the total cost.

Energy costs are the main component of the operational expenditure (OPEX). As long as the heat supply strategy remains unchanged, energy costs are expected to increase only slightly at smaller scales. Conversely, a steep increase in energy costs can be expected if low-cost heat is not available. Ideally, waste heat would be used or, if no waste heat were available, steam from a low-pressure turbine would suffice. In some cases, a dedicated boiler is likely to be required, as is assumed to be the case for the lime kiln, where there is generally limited waste heat available. Fixed and variable operation and maintenance (O&M) costs make up a smaller share of total costs. As O&M costs are assumed to be directly related to and a fraction of the capital cost, the O&M share of total costs rises as the scale is reduced.

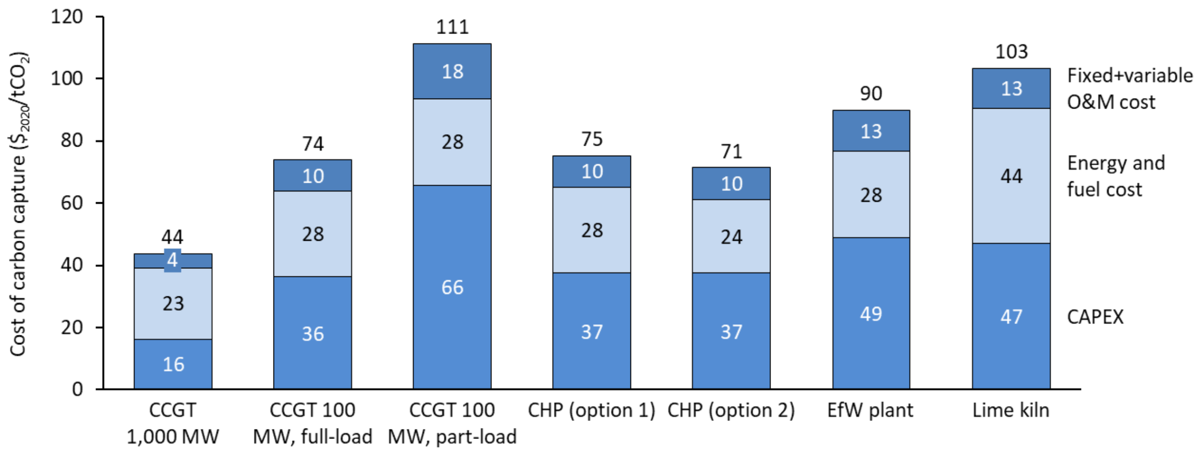

Figure 2: Breakdown for capture cost with conventional solvents

The analysis was repeated for piperazine, an advanced solvent with a lower heat duty of regeneration compared to MEA[1]. Since the importance of energy costs as a share of the total levelised costs diminishes at small scales, improvements to the energy performance of the process will have less of an impact than, say, a focus on reducing CAPEX. Consequently, the use of advanced solvents that lower the heat duty for regeneration brings smaller benefits to small-scale capture plants, compared to their large-scale analogues which are more sensitive to energy and fuel costs.

Current policies can make large-scale capture attractive in some regions but are generally insufficient to incentivise small-scale carbon capture deployment

The impact of current and proposed policies and incentives to make an economically viable case for small-scale carbon capture was assessed for two of the case studies: the CCGT power plant (along with its large-scale analogue) and the lime kiln. The analysis covered the Netherlands, Texas, California, and China. Incentives providing directly monetisable support were modelled for each region, including carbon pricing with an Emissions Trading Scheme (ETS), capital or construction phase support, revenue support, and tax credits as summarised in Table 1. The assessment also accounted for region-specific factors likely to have a significant impact on the project economics, such as energy costs and (unabated) product prices.

Table 1: Current policy incentives in regions under analysis

Incentives	Netherlands	California	Texas	China
Carbon pricing	EU ETS and Dutch carbon tax	Cap-and-Trade programme	-	National ETS
Capital support	-	-	-	Can be available
Revenue support	SDE++[2]	-	-	-
Tax credit	-	Tax credit 45Q	Tax credit 45Q	-

The results in Figure 3, showing the normalised net present value,[3] demonstrate that, while current policies could make large-scale capture attractive in some jurisdictions, they are insufficient to incentivise small-scale capture. The normalised NPV of selected small-scale capture projects is negative for most regions and applications. Capture from a large-scale CCGT, a small-scale CCGT and from a lime kiln are increasingly expensive capture proposals. A one-size-fits-all approach to encourage the deployment of capture plants reveals a gap for small-scale plants, which suggests that a tailored policy approach would be required to incentivise small-scale carbon capture.

[1] Monoethanolamine (MEA) was the benchmark solvent used in this study.

[2] The SDE++ revenue support scheme is not applicable to power production. For this analysis, the modelling represents what its impact would be if SDE++ was applied to CCGTs.

[3] Normalised NPV = NPV divided by the discounted cumulative CO_2 captured

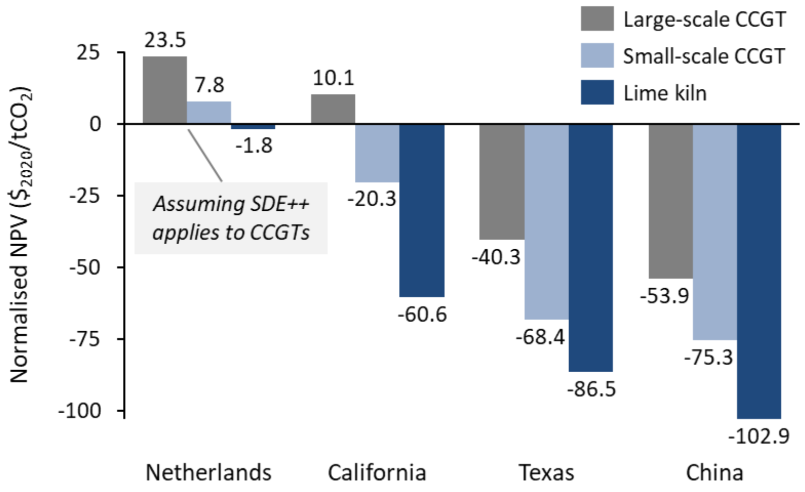

Figure 3: Regional comparison of normalised NPV for different capture applications

In Figure 4, current and projected carbon prices and tax credits are compared to the level of support that would be required to enable economic viability of the small-scale capture projects, i.e., the breakeven carbon price, a considerable gap between the two is evident.

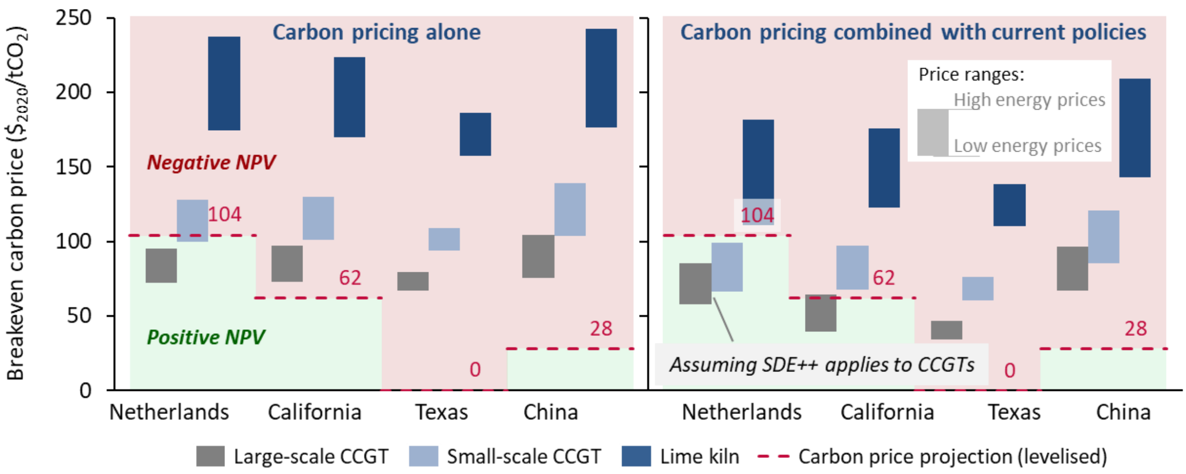

Figure 4: Breakeven carbon prices for the various applications

This implies that small-scale capture projects would not generally be economically viable based on the policies considered and under the assumptions made in this study. The exception would be the case of a capture plant on small-scale CCGT in the Netherlands, and then only if the incentives available to the industry sector were to be made available to power generation. Conversely, lime kilns would require carbon prices much higher than the assumed projections, even when carbon pricing is combined with additional incentives from current policies.

Similarly, the value of the 45Q tax credit in the United States is insufficient for small-scale capture plants to break even. As evidenced in Figure 5, proposed changes to the tax credit under the Build Back Better Act would still fail to incentivise widespread deployment of small-scale capture plants. Capture from small-scale CCGT plants in California might become attractive but the breakeven tax credit for other applications (and in other regions) would be substantially higher than the one being proposed.

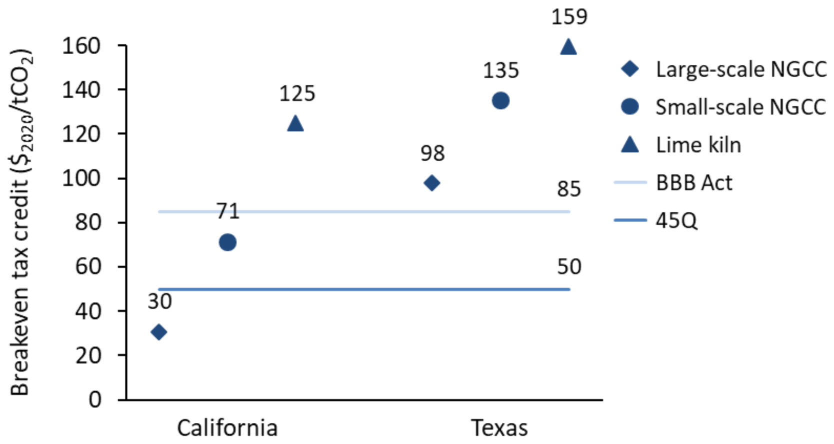

Figure 5: Value of the tax credit required to break even for different capture applications

Without mitigation from additional policy support, product costs can be expected to increase between 44-108% for the case studies considered

Carbon capture costs can deeply impact product costs. In the Netherlands, for instance, if no incentives were present, the total waste disposal cost could increase by 44% and lime costs could increase by 108% if carbon capture is deployed. Incentives that help operators to cover the cost of capture can avoid, at least partially, passing the costs on to consumers. As shown below, because current policy support is insufficient for a lime kiln capture plant operator to break even, the unsupported cost of capture – the portion of the capture cost above revenues or avoided costs – would need to be passed on to the consumers. The price increase for lime in China could be as high as 70%, but would be negligible in the Netherlands because of the higher incentives. This increase does not reflect additional increases tied to energy prices and the phasing out of free allowances.

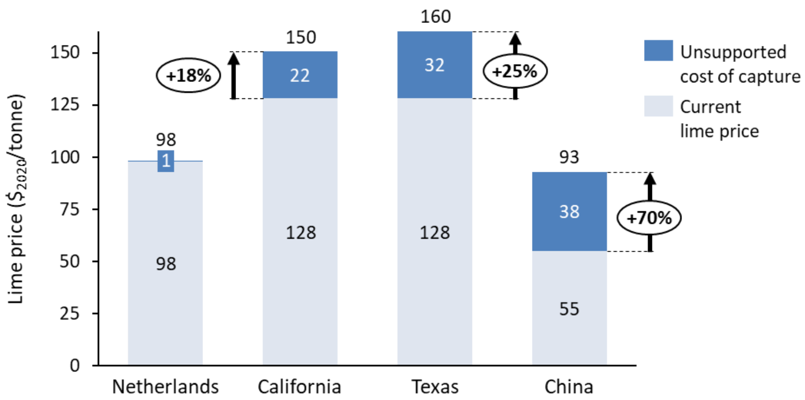

Figure 6: Impact of carbon capture on lime prices

Small-scale capture applications face additional barriers to deployment

A combination of low energy costs, high carbon prices, and additional policy support could help reduce the economic burden of small-scale capture deployments. Even then, small-scale capture deployments will still need to overcome barriers that are likely to affect capture on small-scale applications to a greater degree than on large-scale:

- There is a lack of specific research, development, and demonstration targeting small-scale plants, with gaps in the publicly available literature and a shortage of data.
- The cost of CO_2 infrastructure is likely to be substantially higher for small-scale sites. Two reasons explain this: economies of scale for CO_2 transport are lost and small-scale plants tend to be dispersed and away from anchor emitters.

- Alternative decarbonisation strategies like electrification could have a stronger cost-benefit at smaller scales, especially if they were less capital-intensive.

To address these barriers, tailored policies and incentives that address the cost differential of small-scale capture are likely to be required, as discussed below. Standardisation and/or modularisation of the capture units could help to offset the loss of economies of scale and reduce cost, thus contributing to unlocking private investment in small-scale capture plants.

The market for CO_2 utilisation can be attractive for small-scale emitters and it might offer some premiums compared to carbon prices. However, while those opportunities improve the economics of carbon capture, they may have lower carbon reduction benefits.

Policy should extend the scope and duration of existing incentives and consider more tailored, flexible tools to incentivise small-scale carbon capture

The quantitative analysis presented in this study demonstrates that higher levels of financial support are required to offset the increased costs of small-scale capture and stimulate investment. Beside this, the review of recent and proposed policy changes and incentives for the regions focus of this study has highlighted limitations linked to three areas:

- **Limited scope of policy instruments:** Globally, ETS and tax credits set an inclusion threshold to lower the impact on smaller emitters. For the regions under analysis the threshold oscillates between 25 and 30 $ktCO_2$/year. Plants falling below the threshold are not incentivised to capture their emissions.
- **Short duration:** Some incentives provide initial support under the expectation that, by the end of a support period of up to 15 years, the rising carbon prices will sustain the capture plant's business. The moment in time at which carbon prices will result in a positive net income, however, differs according to the cost of capture. Small-scale capture being relatively more expensive, the duration of current incentives could be too short.
- **Flexibility and tailored support:** Incentives such as carbon pricing and tax credits are inflexible in that their value is the same for all. However, the levels required for breakeven on small-scale plants are much higher than the ones that are projected or under discussion. Alternative incentives that consider the differential costs of capture would be particularly suitable for small-scale capture.

Policies and incentives that tackle current limitations within each of the above areas would significantly encourage small-scale capture deployments. The alternative would be to introduce mechanisms that better enable emitters to pass the additional cost on to consumers, which may be particularly challenging for industrial sites.

Expert Review Comments

Reviewers felt the report was well structured, with graphics that illustrated the results clearly.

There was a view that more industrial cases might have been included among the cases analysed. It was also suggested that there might have been value in exploring further the role incentives might play in stimulating solutions to the harder-to-abate industries as they endeavour to decarbonise.

Given the order of magnitude difference in the scaled parameter (CO_2 mass flow rate), reviewers expressed some reservations regarding the application of a scaling factor for costs, though they recognised that the lack of published cost data left the authors with little alternative. However, with little information available on the costs of smaller-scale capture and efforts to estimate the costs based on data from larger-scale systems, significant uncertainty would be introduced to the results. A concern was that some readers could focus unduly on the comparably high costs for smaller systems and miss nuances on cost uncertainty.

It was considered that assessing the impact on costs of design variations based on a high-level description of the capture process rather than a dedicated process was risky and could reduce confidence in the results. For example, it was felt that varying the capture rate between 87% and 93% should not unduly impact the cost of capture. The TRLs of the three alternative carbon capture technologies explored (advanced chemical absorption, membrane separation, and molten carbonate fuel cells) were also quite different. The various ways of providing the energy for the capture processes and to supply the utilities would be site dependent, making it difficult to compare the technologies fairly or to generalise the application cases of the individual technologies. Moreover, it was pointed out that local environmental regulations would directly impact both CAPEX and OPEX.

Reviewers generally subscribed to the view that modularisation might offer the potential to reduce the costs of small-scale capture applications and felt that this should be explored further. They agreed with the authors that this would be case dependent and should be investigated along with a detailed sensitivity analysis. [Note: Modularisation will be explored further in an upcoming IEAGHG study.]

One reviewer stressed that, even if the CO_2 capture and avoidance cost of small-scale capture plants was relatively high compared to larger applications, they would still be competitive compared with direct air capture.

Conclusions and Recommendations

Technologies with a low capital intensity and high potential for modularisation are likely better suited for small-scale capture.
The potential for modularisation may indeed be more suited to smaller scale applications.

Capture technologies that are best suited for large-scale capture are not necessarily those best suited for small-scale capture.
Amine-based post-combustion capture is the current benchmark capture technology due to its higher maturity. However, its applicability to small-scale carbon capture is challenged by high capital cost and high heat requirements.

Due to the non-linear cost escalation when downscaling, capital-intensive capture technologies may be very costly to deploy, favouring deployment of modularised and mass-manufactured alternatives. Modularisation and standardisation could potentially offset the loss of economies of scale in small-scale deployments through the achievement of economies of scale in the mass-manufacturing process. The standardisation of capture plants however involves trade-offs between high performance and low manufacturing and engineering costs. Correspondingly, different developers are adopting diverging approaches.

Differences in operational modes of large- and small-scale plants also influence the suitability of capture technologies. For instance, processes typically found in smaller-scale industries normally operate at lower temperatures than their large-scale counterparts. As a result, less waste heat might be available for use in many small-scale capture plants, advantaging capture technologies powered by electricity or technologies where regeneration is possible using low-temperature heat.

For these reasons, there are several emerging capture technologies which could be better suited for small-scale capture, for example:

- Advanced chemical absorption, as alternatives to amines could lower both capital and operational costs.
- Membrane separation, as membranes are modular by nature.
- Molten carbonate fuel cells, because of their modularity and because the capture cost is decoupled from the heat supply strategy.

Further development and deployment will however be necessary to draw a verdict on which capture technology is best in each of the different applications.

There is limited published evidence on small-scale carbon capture deployments.
Carbon capture from small-scale applications faces a scarcity of evidence that makes it hard to satisfactorily close the knowledge gap. As noted above, the literature on carbon capture mostly focuses on large-scale power generation or on industrial sites like integrated iron and steel plants or cement plants that do not feature small-scale plants. Despite the abundance of literature on each capture technology, the availability of data concerning small-scale capture is poor. There are many pilots and demonstration projects ongoing but results that include a granular breakdown of performance and costs are often not published. Moreover, there is a lack of publicly available data on the performance of many patented processes. Performance and cost data are required for a detailed comparison originating from a bottom-up analysis.

Capture costs strongly escalate when downscaling the capture plant due to increases in the relative share of capital expenditure in total costs.
Based on available data on capital expenditure (including engineering, procurement and construction), operation and maintenance costs, and energy requirements, the techno-economic assessment estimates the following high-level metrics for each of the above case studies:

- The cost of carbon capture.
- The cost of carbon avoidance.
- The impact on the cost of key products (e.g., lime) or outputs (e.g., electricity and heat).

Estimating the cost of CO_2 transport and storage is beyond the scope of this study, though it is noted that infrastructure costs would also be expected to display strong economies of scale.

Small-scale capture applications face additional barriers to deployment.
A combination of low energy costs, high carbon prices and additional policy support could help reduce the economic burden of deploying small-scale capture plant. As discussed earlier, small-scale capture deployment would still need to overcome barriers that were likely to affect capture on small-scale to a greater degree than on large-scale, including the lack of RD&D targeting small-scale plants, the relative higher cost of CO_2 infrastructure and alternative decarbonisation strategies potentially offering cost-benefit advantages.

Tailored policies and incentives are likely to be required to address these barriers. Standardisation and/or modularisation of the capture units may offer some benefits, contributing to unlocking of private investment in small-scale capture plants.

Policy should extend the scope and duration of existing incentives and consider more tailored, flexible tools to incentivise small-scale carbon capture.
The quantitative analysis presented in this study demonstrates that higher levels of financial support are required to offset the higher relative costs of small-scale capture and stimulate investment. This, of itself, is not sufficient justification for government incentives. However, if private investors can only capture part of the "spillover" benefits of CCS they will invest too little to generate socially desirable levels of innovation. With that in mind, the review of recent and proposed policy changes and incentives for the regions' focus of this study has highlighted limitations linked to three areas:

- Limited scope of policy instruments: Globally, ETS and tax credits set an inclusion threshold to lower the impact on smaller emitters. For the regions under analysis the threshold oscillates between 25,000 and 30,000 t CO_2/year. Plants falling below the threshold are not incentivised to capture their emissions.
- Short duration: Some incentives provide initial support under the expectation that, by the end of a support period of up to 15 years, the rising carbon prices will sustain the capture plant's business. The moment in time at which carbon prices will result in a positive net income, however, differs

according to the cost of capture. Small-scale capture being more expensive, the duration of current incentives may be too short.

- Flexibility and tailored support: Incentives such as carbon pricing and tax credits are inflexible in that their value is the same for all. However, the levels required for breakeven on small-scale plants are much higher than the ones that are projected or under discussion. Alternative incentives that consider the differential costs of capture would be particularly suitable for small-scale capture.

Policies and incentives that tackle limitations within each of the above areas would significantly encourage small-scale capture deployments. The alternative would be to introduce mechanisms that better enable emitters to pass the additional cost on to consumers, which may be particularly challenging for industrial sites – noting that any intervention would need to be justified on market failure grounds to ensure there were overall benefits to society.

Suggestions for Further Work

It is suggested that future work might focus on five areas:

- **Address the paucity of evidence:** More pilots and demonstration projects publishing their results, including a granular break down of performance and costs, would be beneficial for emitters and policy makers alike.
- **Assess alternative separation technologies that could potentially be suitable for small-scale capture:** In addition to post-combustion chemical absorption, membrane separation and molten carbonate fuel cells were identified as being suitable for small-scale deployment on a qualitative basis. Further assessment is required to understand the cost implications of small-scale capture for these technologies and potential cost reductions.
- **Compare small-scale carbon capture with alternative decarbonisation pathways:** A comparison between alternative decarbonisation pathways such as fuel switching and electrification is needed to advance the understanding of the scale at which carbon capture becomes more or less attractive.
- **Compare custom-engineered and mass-produced modular capture plants:** The two diverging trends are custom-engineered solutions to optimise performance or mass-produced standardised units to optimise manufacture costs. Modular capture plants may be best suited for cases with a uniform CO_2 stream. An assessment of the cases where each approach could become preferable is required to understand the level of potential cost reductions associated to them and the robustness of a standardised approach to site-specific conditions. [Note: Modularisation is the theme of a forthcoming IEAGHG study.]
- **Tailor policy design for small-scale capture:** This study identified that current policies and incentives will likely fail to stimulate private investment in small-scale capture and suggested potential improvements. Further work is required to incorporate both a public and private perspective, to include the impact of capital financing, and to understand the social and economic implications of policy decisions.

Techno-Economic Assessment of Small-Scale Carbon Capture for Industrial and Power Systems

Final report

for

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This report was authored by the project lead, Element Energy, an ERM Group Company.

Element Energy is a leading low carbon energy consultancy working in a range of sectors including carbon capture and storage, low carbon transport, low carbon buildings, renewable power generation, energy networks, and energy storage. Element Energy works with a broad range of private and public sector clients to address challenges across the low carbon energy sector and provides insight and analysis across all parts of the CCS chain.

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The Department of Chemical Engineering of the University of Manchester is ranked 27th in world ranking on Chemical Engineering. The department is leading research in the area of catalysis, process integration and sustainable industrial process. The Spallina's group research is focussing on carbon capture and storage, low carbon hydrogen and chemical production, advanced reactor engineering by using gas-solid processes and membrane-based technology. The research network involves large industries, SME, first class universities in UK and abroad and large research centres in the area of energy, chemistry and materials development with 5 PhDs and 5 Postdocs working on private and public funded research projects by UKRI, EU commission and BEIS.

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Executive Summary

This study addresses the knowledge gap on small-scale carbon capture applications and assesses four case studies in the industry and power generation sectors

Carbon Capture, Utilisation, and Storage (CCUS) is widely recognised as a key part of the toolkit of solutions needed to reach net zero greenhouse gas emissions. **Up to now, most analysis on the deployment of carbon capture for power and industrial application has focused on large-scale sites** with annual emissions of several hundreds of thousands, if not millions, of tonnes of CO_2. This reflects the dominant focus of technology developers on deploying solutions tackling over 1 $MtCO_2$/year. This focus is generally explained by the fact that CCUS projects are considered to offer better economics at larger scales, due to economies of scale with both the capture plant and the transport and storage infrastructure.

A significant share of the emissions from industry and power generation however arises from smaller sites, as defined by their level of CO_2 emissions. Decarbonisation of such sites will be required to honour net zero pledges, which justifies the increased attention to the need to capture CO_2 from these sites. Also considering the increased focus on relatively costly decarbonisation solutions such as direct air capture, carbon capture from small-scale emitters could hold the key to cost-effective decarbonisation, as well as representing an opportunity for smaller sites to decarbonise. Accordingly, technology developers are preparing to meet growing demand for carbon capture solutions by small-scale emitters.

There is however a knowledge gap on small-scale capture applications and associated technology options. It is thus important to fully understand the techno-economics of capture on small-scale applications and the policy levers required to develop the market and enable technology uptake. As a step to bridge the knowledge gap, Element Energy was commissioned by the IEAGHG to review publicly available literature and collect input from industry stakeholders and technology developers to:

- Review the evidence base for small-scale carbon capture.
- Evaluate the availability of technology solutions suitable for small-scale carbon capture, highlighting associated trends.
- Provide a techno-economic assessment of carbon capture on small-scale applications for power generation and industrial processes.
- Establish how existing policies and incentives could contribute to the economic viability of carbon capture from small-scale applications.

A working definition of small-scale power and industrial applications for carbon capture was formulated for the purposes of this study based on analysis of data on CO_2 point sources from the sectors of interest. This revealed qualitative differences between large- and small-scale power and industrial applications, as some industrial processes or power plant configurations can in fact only be found at large scales. For example, there are no small oil refineries or integrated iron and steel sites. This analysis led to the selection of independent **thresholds** for defining what constitutes a small-scale capture application in the power generation and industry sectors:

- **Power generation** – plants with an unabated installed capacity of **up to 100 MWe**.
- **Industry** – sites emitting **up to 100 $ktCO_2$/year** from point sources.

Four case studies were selected for detailed techno-economic assessment focusing on representative processes generally falling within this study's working definition of small-scale:

- Gas-fired power generation, with a focus on a natural gas-fired combined cycle gas turbine (CCGT). Variants include unabated generation capacity of 100 MWe under full-load operation, 100 MWe under part-load operation, and a large-scale analogue 1,000 MWe CCGT.
- Natural gas-fired co-generation, or combined heat and power (CHP). A CHP plant with an unabated capacity of 100 MW (25 MW_e + 75 MW_{th}) was modelled.
- Energy from Waste (EfW). A plant emitting 100 ktCO_2/year was assessed.
- Lime kilns. A kiln emitting 100 ktCO_2/year from the production of 109 kt lime/year was included.

While these thresholds are considered representative for the case studies discussed below, it is acknowledged that larger sites also exist in the selected sectors.

Considering that CCGT plants are found on both small and large scales, a comparison was done between a small-scale prototype and its large-scale analogue to better understand the cost implications of scaling down capture units.

Technologies with a low capital intensity and high potential for modularisation are likely better suited for small-scale capture

Capture technologies that are best suited for large-scale capture are not necessarily those best suited for small-scale capture. Amine-based post-combustion capture is the current benchmark capture technology due to its higher maturity. However, its applicability to small-scale carbon capture is challenged by high capital cost and heat requirements.

Due to the non-linear cost escalation when downscaling, capital-intensive capture technologies may be very costly to deploy, favouring deployment of modularised and mass-manufactured alternatives. **Modularisation and standardisation could potentially offset the loss of economies of scale in small-scale deployments through the achievement of economies of scale in the mass-manufacturing process**. The standardisation of capture plants however involves trade-offs between high performance and low manufacturing and engineering costs. Correspondingly, different developers are adopting diverging approaches.

Differences in operational modes of large- and small-scale plants also influence the suitability of capture technologies. For instance, processes typically found in smaller-scale industries typically operate at lower temperatures than their large-scale counterparts. As a result, **less waste heat might be available for use in many small-scale capture plants**, advantaging capture technologies powered by electricity, or which can be regenerated via low-temperature heat.

For these reasons, there are several emerging capture technologies which could be better suited for small-scale capture:

- **Advanced chemical absorption**, as alternatives to amines could lower both capital and operational costs.
- **Membrane separation**, as membranes are modular by nature and run on electricity.
- **Molten carbonate fuel cells**, because of their modularity and because the capture cost is decoupled from the heat supply strategy.

Further development and deployment will however be necessary to draw a verdict on which capture technology is best in each of the different applications. Alternative capture technologies not featured here could also become competitive.

There is limited published evidence on small-scale carbon capture deployments

Carbon capture from small-scale applications faces a scarcity of evidence that makes it hard to satisfactorily close the knowledge gap. As noted above, the literature on carbon capture mostly focuses on large-scale power generation or on industrial sites like integrated iron and steel plants or cement plants that do not feature small-scale plants. Despite the abundance of literature on each capture technology, **the availability of data concerning small-scale capture is poor**. There are many pilots and demonstration projects ongoing but results that include a granular breakdown of performance and costs are often not published. Moreover, there is a **lack of publicly available data on the performance of many patented processes**. Performance and cost data are required for a detailed comparison originating from a bottom-up analysis.

Capture costs strongly escalate when downscaling the capture plant due to increases in the relative share of capital expenditure in total costs

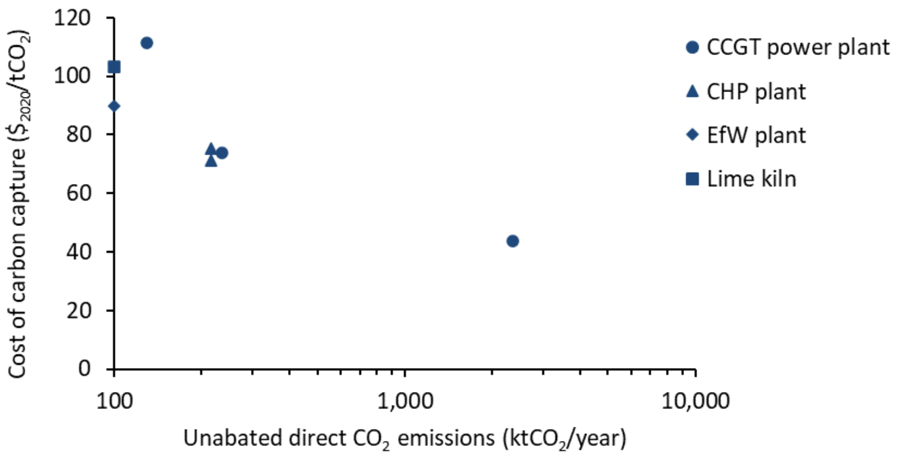
Based on available data on capital expenditure (including engineering, procurement and construction), operation and maintenance costs, and energy requirements, the techno-economic assessment estimates the following high-level metrics for each of the above case studies:

- The cost of carbon capture.
- The cost of carbon avoidance.
- The impact on the cost of key products (e.g., lime) or outputs (e.g., electricity and heat).

Estimation of the cost of CO_2 transport and storage is instead beyond the scope of this study, though it is remarked that infrastructure costs are also expected to display strong economies of scale.

Due to the general unavailability of data on capital costs for small-scale applications, **the cost of carbon capture on a small scale was estimated by scaling down relevant benchmarks for large-scale plants via a power law**. This constitutes a key limitation of the study that may only be addressed via the publishing of relevant cost data by technology and project developers.

The results show a significant cost escalation when the size of the capture unit is scaled down. The figure below exhibits the negative correlation between the unit cost of capture and the scale of the emissions for the four case studies and their variations for amine-based post combustion capture. Whilst the large-scale CCGT power plant shows the lowest cost of carbon capture (\$44/tCO_2), the EfW plant and the lime kiln – the two case studies with the lowest level of unabated CO_2 emissions – show a much higher cost of capture, ranging from \$90/tCO_2 to \$103/tCO_2.

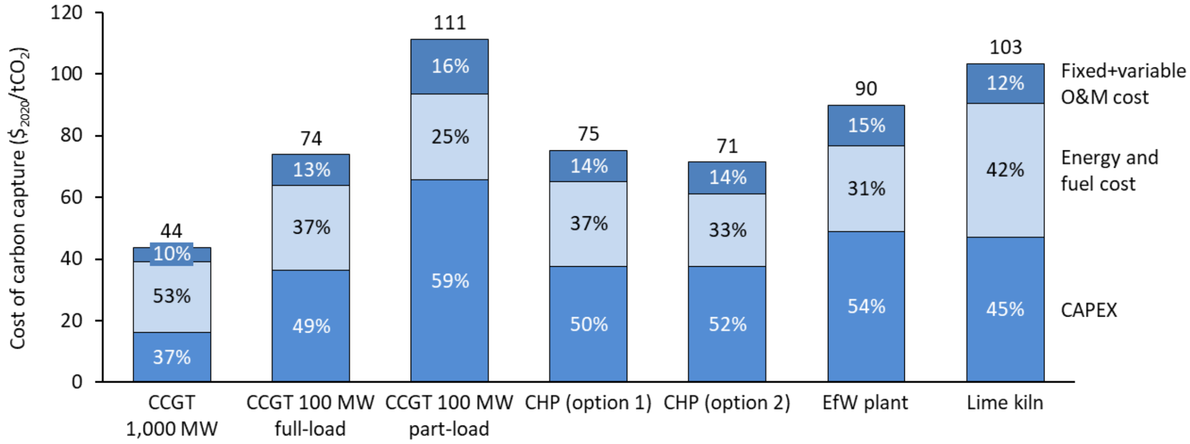


Cost of carbon capture on selected case studies

Efforts to lower the cost of small-scale capture should primarily target capital costs

Future cash flows were discounted to determine a net present value. **Capital expenditures (CAPEX) increasingly become the dominant cost factor at smaller scales.** As shown below, CAPEX represents 37% of the levelised capture costs for a large-scale CCGT power plant, but its importance grows to 49% for its small-scale analogue. **The capital cost importance also grows as capacity factors reduce;** for a small-scale CCGT power plant operated part-load, capital costs account for 59% of the total cost. A higher discount rate, linked to a higher cost of capital, would increase the CAPEX importance even more.

Energy costs are the main component of the operational expenditure (OPEX). **Energy costs are expected to increase only slightly at smaller scales, so long as the heat supply strategy remains unchanged. Conversely, a steep increase in energy costs can be expected if low-cost heat is not available.** Ideally, waste heat would be used if possible, or steam from a low-pressure turbine if no waste heat is available. In some cases, a dedicated boiler is likely to be required, as is assumed to be the case for the lime kiln, where there is generally limited waste heat available. Indeed, CAPEX dominates the cost of capture even in the case of the lime kiln. Fixed and variable operation and maintenance (O&M) costs hold a smaller share of total costs. As O&M costs are assumed to be a fraction of the capital cost, the O&M share in total costs increases as scale is reduced.



Breakdown for capture cost with conventional solvents

The analysis was repeated for piperazine, an advanced solvent with a lower heat duty of regeneration compared to MEA, the benchmark solvent. Since the importance of energy costs as a share of the total levelised costs diminishes at small scales, improvements to the energy performance of the process will have a lower impact. Consequently, **the use of advanced solvents that lower the heat duty for regeneration brings smaller benefits in small-scale capture plants**, compared to large-scale analogues which are more sensitive to energy and fuel costs.

Current policies can make large-scale capture attractive in some regions but are generally insufficient to incentivise small-scale carbon capture deployment

The impact of current and proposed policies and incentives to make an economically viable case for small-scale carbon capture was assessed for two of the case studies: the CCGT power plant (with its large-scale analogue), and the lime kiln. The analysis covered **the Netherlands, Texas, California, and China**. Incentives providing directly monetizable support were modelled for each region, including **carbon pricing** with an Emissions Trading Scheme (ETS), **capital or construction phase support, revenue support, and tax credits**, as summarised in the table below. The assessment also accounted for region-specific factors likely to have a significant impact on the project economics like energy costs and (unabated) product prices.

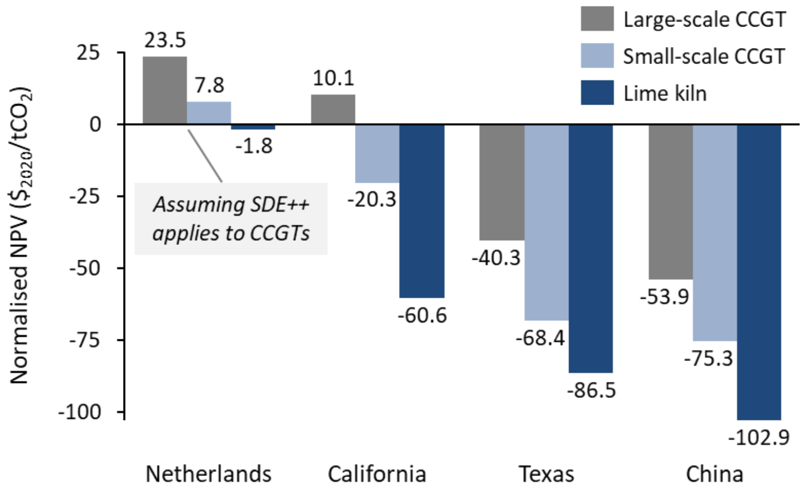
Current policy incentives in regions under analysis

Incentives	Netherlands	California	Texas	China
Carbon pricing	EU ETS and Dutch carbon tax	Cap-and-Trade program	-	National ETS
Capital support	-	-	-	Can be available
Revenue support	SDE++[1]	-	-	-
Tax credit	-	Tax credit 45Q	Tax credit 45Q	-

The results below show the normalised net present value (NPV), defined as the NPV divided by the discounted cumulative CO_2 captured. These results show that, whilst current policies can make large-scale capture attractive in some jurisdictions, they are not sufficient to incentivise small-scale capture. As shown in the figure below, the normalised NPV of selected small-scale capture projects is negative for most regions and applications. Only in the Netherlands do all industrial and power applications result

[1] The SDE++ revenue support scheme is not applicable to straightforward power production. The modelling represents what its impact would be if it applied to CCGTs.

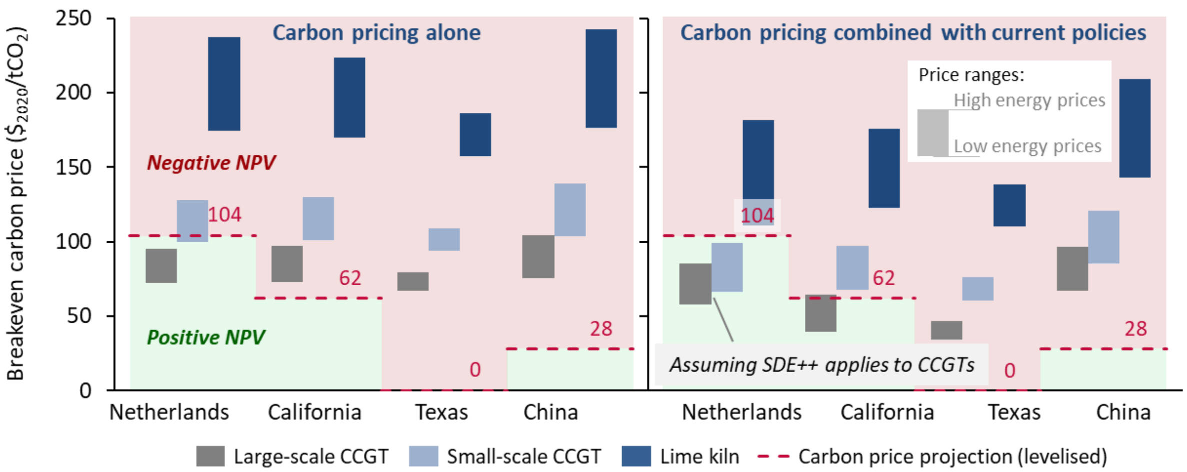
in a positive (or very close to zero) normalised NPV. Capture from a large-scale CCGT, a small-scale CCGT and from a lime kiln are increasingly expensive capture proposals. A one-size-fits-all approach to encouraging the deployment of capture plants reveals a gap for small-scale plants. This suggests that **a tailored policy approach would be required to incentivise small-scale carbon capture**.



Regional comparison of normalised NPV for different capture applications

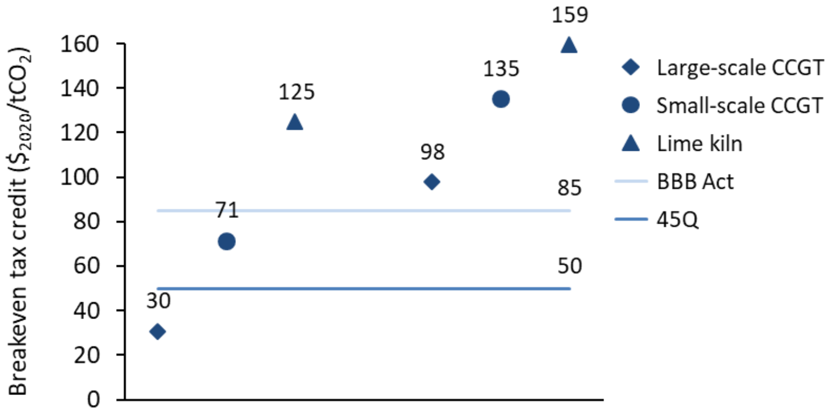
There is a considerable gap between the level of support required to break even and that provided by available incentives such as carbon pricing or tax credits

By comparing current and projected carbon prices and tax credits to the level of support that would be required to enable economic viability of the small-scale capture projects – i.e., the breakeven carbon price – it is easy to observe a considerable gap between the two. This implies that small-scale capture projects would not generally be economically viable based on the policies considered and under the assumptions made in this study. The only exception is the case of a capture plant on small-scale CCGT in the Netherlands, which could break even under the more optimistic energy price assumptions. Conversely, lime kilns would require carbon prices that are much higher than the assumed projections, even when carbon pricing is combined with additional incentives from current policies.



Range of breakeven carbon prices for different applications, geographies, and energy prices

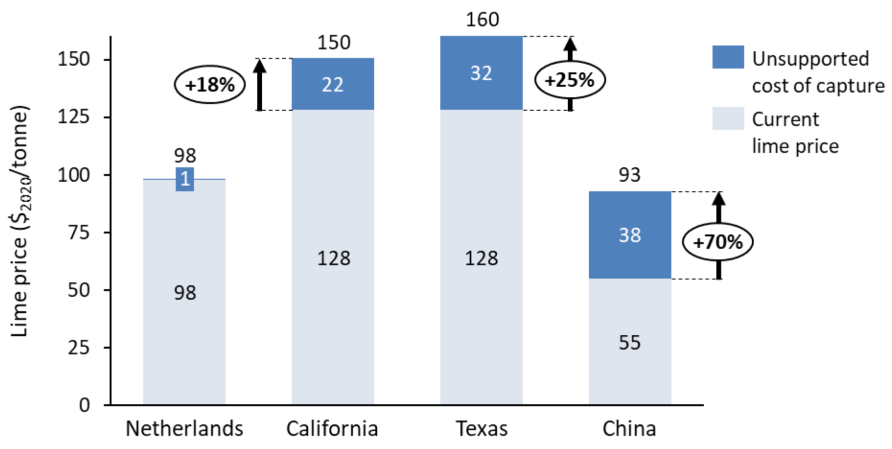
Similarly, the value of the 45Q tax credit in the United States is insufficient for small-scale capture plants to break even. As evidenced below, proposed changes to the tax credit under the Build Back Better Act would still fail to incentivise widespread deployment of small-scale capture plants. Capture from small-scale CCGT plants in California might become attractive but the breakeven tax credit for other applications is substantially higher than the one being proposed.



Value of the tax credit required to break even for different capture applications

Product costs can be expected to increase between 44-108% for the case studies considered, without mitigation from additional policy support

Carbon capture costs can deeply impact product costs. In the Netherlands, for instance, if no incentives were present, **the total waste disposal cost could increase by 44% and lime costs could increase by 108%** if carbon capture is deployed. Incentives that help operators to cover the cost of capture can avoid, at least partially, passing the costs on to consumers. As shown below, because current policy support is insufficient for a lime kiln capture plant operator to break even, the unsupported cost of capture – the portion of the capture cost above revenues or avoided costs – would need to be passed on to the consumers. The price increase for lime in China could be as high as 70%, but it would be negligible in the Netherlands because of higher incentives. This increase does not reflect additional increases tied to energy prices and the phasing out of free allowances.



Impact of carbon capture on lime prices

Small-scale capture applications face additional barriers to deployment

A combination of low energy costs, high carbon prices, and additional policy support could help reduce the economic burden of small-scale capture deployments. Even then, small-scale capture deployments will still need to overcome barriers that are likely to affect capture on small-scale to a greater degree than on large-scale:

- There is a **lack of specific research, development, and demonstration** targeting small-scale plants, with evident gaps in the publicly available literature and shortage of data.
- The **cost of CO_2 infrastructure** is likely to be substantially higher for small-scale sites. Two reasons explain this: economies of scale for CO_2 transport are lost and small-scale plants tend to be dispersed and away from anchor emitters.
- **Alternative decarbonisation strategies like electrification could have a stronger comparative advantage at smaller scales**, especially if they are less capital-intensive.

To address these barriers, tailored policies and incentives that address the cost differential of small-scale capture are likely to be required, as discussed below. **Standardisation and/or modularisation** of the capture units could however help to offset the loss of economies of scale and reduce cost, thus contributing to unlocking private investment in small-scale capture plants.

The market for CO_2 utilisation can be attractive for small-scale emitters and it might offer some premiums compared to carbon prices. However, whilst those opportunities improve the economics of carbon capture, they may have lower carbon reduction benefits.

Policy should extend the scope and duration of existing incentives and consider more tailored, flexible tools to incentivise small-scale carbon capture

The quantitative analysis presented in this study demonstrates that higher levels of financial support are required to offset the increased costs of small-scale capture and stimulate investment. Beside this, the review of recent and proposed policy changes and incentives for the regions focus of this study has highlighted limitations linked to three areas:

- **Limited scope of policy instruments:** Globally, ETS and tax credits set an inclusion threshold to lower the impact on smaller emitters. For the regions under analysis the threshold oscillates between 25 and 30 ktCO_2/year. Plants falling below the threshold are not incentivised to capture their emissions.
- **Short duration**: Some incentives provide initial support under the expectation that, by the end of a support period of up to 15 years, the rising carbon prices will sustain the capture plant's business. The moment in time at which carbon prices will result in a positive net income, however, differs according to the cost of capture. Small-scale capture being more expensive, the duration of current incentives could be too short.
- **Flexibility and tailored support**: Incentives such as carbon pricing and tax credits are inflexible in that their value is the same for all. However, the levels required for breakeven on small-scale plants are much higher than the ones that are projected or under discussion. Alternative incentives that consider the differential costs of capture would be particularly suitable for small-scale capture.

Policies and incentives that tackle current limitations within each of the above areas would significantly encourage small-scale capture deployments. The alternative would be to introduce mechanisms that better enable emitters to pass the additional cost on to consumers, which may be particularly challenging for industrial sites.

Recommendations for further work

It is recommended that future work focuses on five areas:

- Address the paucity of evidence: More pilots and demonstration projects publishing their results, including a granular break down of performance and costs, would be beneficial for emitters and policy makers alike.

- Assess alternative separation technologies that could potentially be suitable for small-scale capture: In addition to post-combustion chemical absorption, membrane separation and molten carbonate fuel cells were identified as being suitable for small-scale deployment on a qualitative basis. Further assessment is required to understand the cost implications of small-scale capture for these technologies and potential cost reductions.
- Compare small-scale carbon capture with alternative decarbonisation pathways: A comparison between alternative decarbonisation pathways such as fuel switching is needed to advance the understanding of the scale at which carbon capture becomes less attractive.
- Compare custom-engineered and mass-produced modular capture plants: The two diverging trends in modularisation are custom-engineered solutions to optimise performance or mass-produced standardised units to optimise manufacture costs. Modular capture plants may be best suited for cases with a uniform CO_2 stream. An assessment of the cases where each approach could become preferrable is required to understand the level of potential cost reductions associated to them and the robustness of a standardised approach to site-specific conditions.
- Tailor policy design for small-scale capture: This study identified that current policies and incentives will likely fail to stimulate private investment in small-scale capture and suggested potential improvements. Further work is required to incorporate both a public and private perspective, include the impact of capital financing, and understand the social and economic implications of policy decisions.

Contents

Acronyms

ACCR	Annual Capital Charge Ratio
BBB Act	Build Back Better Act
CCA	Cost of CO_2 Avoided
CCC	Cost of CO_2 Captured
CCGT	Combined Cycle Gas Turbine
CCUS	Carbon Capture, Utilisation, and Storage
CHP	Combined Heat and Power
EfW	Energy from Waste
EOR	Enhanced Oil Recovery
ETS	Emissions Trading Scheme
GHG	Greenhouse Gas
IRR	Internal Rate of Return
MCFC	Molten Carbonate Fuel Cell
MEA	Monoethanolamine
CCGT	Combined Cycle Gas Turbine
NPV	Net Present Value
OEM	Original Equipment Manufacturer
OCGT	Open Cycle Gas Turbine
PZ	Piperazine
SPECCA	Specific Primary Energy Consumption for CO_2 Avoided
T&S	Transport and Storage
TAC	Total Annualised Cost
TEA	Techno-Economic Assessment
TEC	Total Equipment Cost
TPC	Total Plant Cost
TCR	Total Capital Requirement
tpd	Tonnes per day (of CO_2)
TRL	Technology Readiness Level

1 Introduction

1.1 Study context

Carbon Capture, Utilisation, and Storage (CCUS) is widely recognised as a key part of the toolkit of solutions needed to reach net zero greenhouse gas emissions,[2] with numerous applications across a low-carbon energy system. CCUS can help decarbonise power generation, energy intensive industries, and hydrogen production, while also enabling nascent clean technologies like negative emissions. Global CCUS deployment still remains limited notwithstanding.

To date, most analysis on the deployment of carbon capture for power and industrial application has focused on large-scale sites with annual emissions of several hundreds of thousands – in many cases even millions – of tonnes of CO_2. Capture plants for large-scale emitters are widely considered to offer the best project economics – though not yet always commercially viable – thanks to their intrinsic economies of scale. Moreover, initial CCUS projects are expected to be built around large-scale "anchor" emitters, to allow for the development of CCS hubs that ensure economies of scale of the deployment of transport and storage (T&S) infrastructure and minimise cross-chain risks.

There are however a significant number of industrial sites and power assets with smaller but still significant emissions. In many cases, these are located away from the main clusters. Carbon capture from these sites could hold the key to more cost-effective decarbonisation. This is particularly so in consideration of the increased focus on relatively high-cost carbon abatement solutions such as direct air capture, which generally features high levels of energy requirements to extract CO_2 from atmospheric air with very low CO_2 concentrations of ~400ppm. Smaller industrial emitters are key to the economic development of local communities, and thus their decarbonisation would enable the preservation of industrial jobs and the development of local skills, supply chains, and a just transition.

Many small sites face additional challenges in the quest to decarbonise. Smaller sites can have higher running costs as they do not benefit from economies of scale. They often compete in the same commodity markets as larger sites, meaning their ability to finance decarbonisation projects may be more limited. Compared to large emitters, usually located in heavily industrialised areas such as industrial clusters, many small sites are either located around densely populated areas, where availability of land may be limited, or in remote areas far from the main industrial clusters, which implies constrained access to transport and storage infrastructure.

Carbon capture could represent an opportunity for small sites to decarbonise. However, there is a knowledge gap on small-scale capture applications and the technology options have not been fully mapped out. Targeting capture on a small scale could either come from scaling up technologies today demonstrated only on a pilot scale or from scaling down the large industrial technologies. Smaller-scale capture solutions have been previously used in separation in biogas upgrading and in the case of fermentation, where CO_2 is often already recovered and reused for other purposes. Multiple other solutions are emerging on the market, including new modular technologies and even technologies designed for capturing emissions from ships. **It is thus important to fully understand the techno-economics of capture on small-scale applications and the policy levers required to develop the market and enable technology uptake**.

1.2 Project scope and methodology

This study aims to bridge the knowledge gap on small-scale CO_2 capture applications via an extensive techno-economic assessment covering multiple sectors and capture technologies. It also provides a

[2] IEA, 2020, CCUS in Clean Energy Transitions.

policy assessment that aims to evaluate current and proposed policies and incentives in establishing an economically viable case for deployment of CO_2 capture. Over a period of seven months, with input from stakeholders from industry and technology developers, and drawing from literature published on CCS, the project has identified the potential for small-scale carbon capture, has assessed the techno-economics of small-scale CO_2 capture, and has analysed the impact of policies and incentives on the affordability of CO_2 capture.

The primary objective of this study is to provide a techno-economic assessment (TEA) of CO_2 capture on small-scale applications for power generation and industrial processes. CO_2 capture is widely seen as an essential tool for the deep decarbonisation of sectors like power generation, waste management, cement and lime, and other hard-to-abate sectors. In this context, this study aims to specifically understand how differences (e.g., technology availability, costs, and requirements) between small-scale and large-scale applications, which have generally been the focus of prior analysis, can impact the economic viability of CO_2 capture on a small scale.

As a first step to answering this question, the TEA focuses on those technologies that are technically more mature and will specifically quantify three sets of costs for the selected technologies and applications: **the cost of products and services** (and how these are impacted by CO_2 capture), **the cost of CO_2 capture**, and **the cost of CO_2 avoided**. Where appropriate, these cost estimates are compared with those for large-scale plant analogues obtained from the literature to quantify the cost implications of capturing carbon at smaller scale.

The second objective of this study is to establish how far recent and proposed policy changes and incentives can contribute to enabling the business case for CO_2 capture from small-scale applications in selected regions. A corresponding aim of this study is to develop recommendations for policy makers to support the sector as well as recommendations for further work.

The report is structured as follows:

- **Chapter 2** provides a working definition of small-scale capture plants. This chapter considers different metrics and defines a threshold for small-scale plants. This leads to the selection of four case studies to be progressed to the techno-economic assessment.
- **Chapter 3** introduces an overview of key carbon capture technologies. A description of the status and prospects for capture from small-scale applications is complemented with qualitative considerations derived from the research and validated via stakeholder engagement.
- **Chapter 4** presents the techno-economic assessment, including its methodology, and the results for the four case studies
- **Chapter 5** describes the policy assessment. It introduces the modelling methodology and presents the results from the policy modelling for different regions.
- **Chapter 6** discusses barriers and enablers for small-scale capture. This is complemented by recommendations for policy makers.
- Finally, **Chapter 7** draws conclusions and recommendations for further works.

2 A working definition for small scale

As a starting point, it is important to define what should be considered small scale for capture applications, as this concept is ambiguous. It is thus essential to adopt a working definition for small-scale applications to guide the selection of relevant case studies and the analysis of barriers and enablers. A potential working definition is characterised by two main aspects:

- The **metric** used – this could either relate to the tonnes of CO_2 emitted – and potentially captured – every year (tCO_2/year) or to the output from the plant where capture is deployed.
- An absolute level or **threshold** for the chosen metric – this would determine whether the plant can be considered "small" or not.

For the purpose of this study, we have adopted different definitions for small-scale power and industrial applications:

- **Power generation – plants with an unabated installed capacity of up to 100 MWe.**
- **Industry – sites emitting up to 100 $ktCO_2$/year from point sources.**

In the following Sections we will explain the reasoning behind the definitions for small-scale CO_2 capture. Additional considerations on the selections of metrics and the databases used for the analysis are offered in Appendix 8.1. Having done that, we will present an overview of small-scale capture applications that were selected to be progressed to the techno-economic assessment.

2.1 Power generation

For power generation, the use of a metric based on tonnes of CO_2 emitted every year is challenged by the operational differences between power plants. Indeed, power plants with the same capacity but different load factors will differ in their emissions level. Those two plants, however, would still require a similarly sized capture plant. This distinction is not limited to separate assets: if a power plant were to shift from baseload generation to load-following operation then its emissions would decrease but the size of the capture plant would not.[3] Hence, the unabated installed capacity is a better metric to assess the scale of capture plants for power generation. As the penetration of variable renewable energy sources in power systems increases it is expected that fossil fuel-fired power plants will need to operate with lower load factors. If combined with capture plants, those load-following or peaking power plants might lead to higher capture costs as the capital would need to be amortised in fewer operating hours.

In the UK, the National Atmospheric Emissions Inventory (NAEI) Emissions from Large Point Sources dataset covers annual CO_2 emissions from minor and major power producers.[4] Bearing in mind the limitations of a metric based on tonnes of CO_2 emitted every year for power generation, it is a good starting point to understand where an indicative threshold could fall. Figure 1 presents a histogram of direct emissions from UK power generators, for minor and major power producers alike. There is an apparent bimodal distribution: whilst minor power producers are largely grouped under the first mode, major power producers present a first mode at around 2 $ktCO_2$/year and a second mode at 1.6 $MtCO_2$/year. A potential threshold could be set at 300 $ktCO_2$/year – at the tail of the second mode –, so that it includes virtually all minor power producers and a small percentage of the producers grouped around the second mode.

[3] The design of the capture plant could present some differences between both cases, introduced to increase the flexibility of the capture plant operation. For instance, for post-combustion chemical absorption modifications could include buffer tanks for CO_2-rich and lean solvent, or an oversized stripper column.

[4] Major power producers are defined as those companies whose prime purpose is the generation of electricity. NAEI data refers to 2019 emissions.

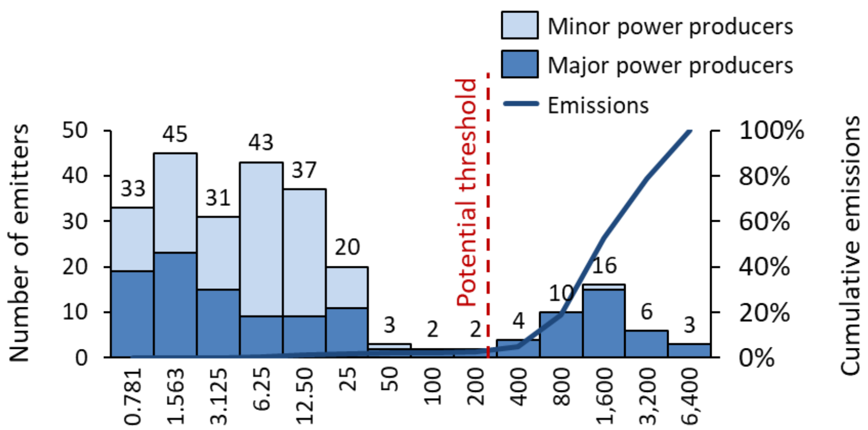


Figure 1: Histogram of direct emissions for UK power generators

Under such a threshold, 82% of emitters would be classified as small-scale power generators. They would represent 4% of total power generation direct emissions, as it can be seen in Figure 2.

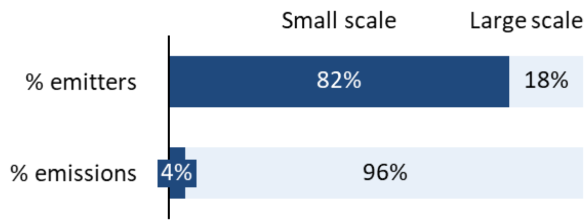


Figure 2: Split of UK power generation emissions by scale with a threshold of 300 $ktCO_2$/year

The insights obtained from the analysis of annual emissions from power generators can shed some light on setting a threshold based on the unabated net installed capacity. Figure 3 illustrates the distribution of major power producers by size and plant type, obtained from Table 5.11 from the Digest of UK Energy Statistics.[5] The distribution is also bimodal, but the two modes are closer and less well-defined. In effect, many UK power generation assets were operated at only 10 to 20% load factors in 2019. Because many of the smaller power plants with lower efficiency, such as diesel-run open cycle gas turbines (OCGTs), operate as peaking plants, the spread of the direct emissions is larger than that of the installed capacity.

The threshold between small-scale and large-scale is set at 100 MWe. This threshold enables some overlap in types of power plants between both categories. Moreover, if applied to a natural gas-fired combined cycle gas turbine (CCGT) on baseload operation it would be equivalent to annual emissions of around 250 $ktCO_2$/year[6] – which is close to the threshold from Figure 1. Figure 3 also shows that there is a qualitative difference between the emitters as the size varies. That qualitative difference between power generators at different scales reveals that there may be few possibilities for comparing small-scale and large-scale analogous capture plants. The type of plants belonging to each side of the threshold differ:

[5] Department for Business, Energy & Industrial Strategy, 2021, *Digest of UK Energy Statistics (DUKES)*.
[6] Approximate calculation, considering specific direct emissions from natural gas of 200 $kgCO_2$/MWh LHV, an efficiency of 60% and a load factor of 85%.

- Small-scale power generation is dominated by diesel- and natural gas-fired OCGTs, and biomass-fired power plants. There are only a few natural gas fired (CCGTs) below 100 MWe;[7]
- Large-scale power generation is characterised by natural gas fired CCGTs, coal power plants, and some biomass units. At the lower end of the spectrum there are a few diesel- and natural gas-fired OCGTs.

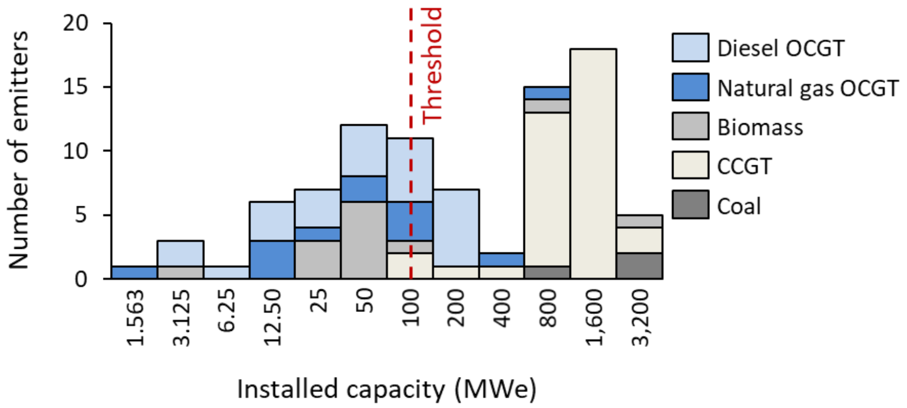


Figure 3: Histogram of installed capacity for UK major power producers by power plant type

Gas turbines are the only power generation asset appearing on both small and large scales. They appear most often in combined-cycle configuration on large scale (CCGT) and standalone on small scale (OCGT), but there is some overlap.

2.2 Industry

Industry appliances work with significantly higher load factors than power generation assets.[8] Hence, it is appropriate to define scale for industrial capture plants based on the emissions volumes. Figure 4 shows the distribution of direct emissions from UK industrial emitters. Emitters include refineries, the chemical industry, ferrous and non-ferrous metal industries, cement and lime plants, other mineral industries such as ceramics and glass, paper and pulp plants and the food and drink industries. The mode is 14 ktCO_2/year, while the mean is 80 ktCO_2/year. **The threshold is set at 100 ktCO_2/year**. This way, the emitters from the upper tail are categorised as those corresponding to large-scale capture plants. As illustrated in Figure 5, with a threshold of 100 ktCO_2/year 84% of industrial emitters, representing 19% of direct industrial emissions, are classified as suited for small-scale capture plants.

[7] Most major gas turbine OEMs offer CCGTs at capacities of around 100 MW or under. Examples include Mitsubishi's H-25 series, Siemens's SGT-800 turbine, or GE's 6F series.
[8] See, for example, Element Energy, 2019, *Hy4Heat WP6: Conversion of Industrial Heating Equipment to Hydrogen*.

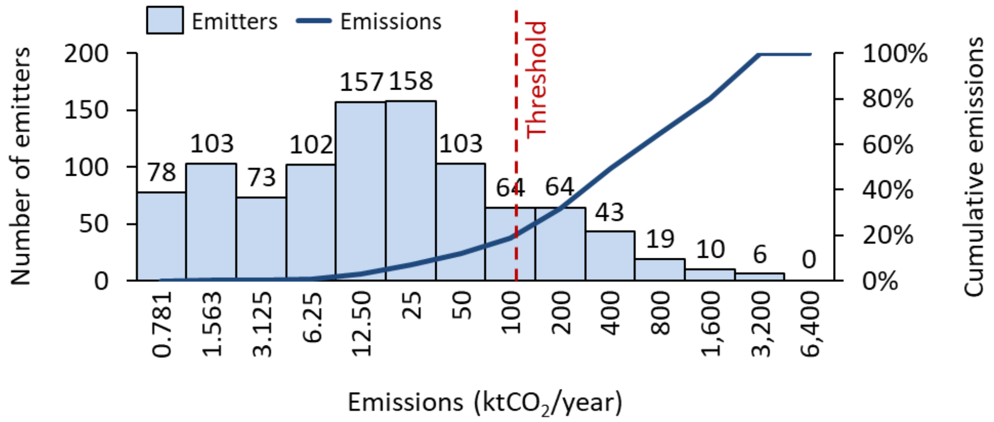


Figure 4: Histogram of direct emissions for UK industrial emitters

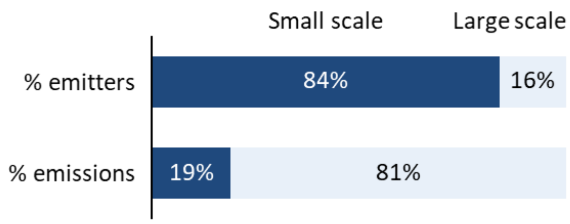


Figure 5: Split of UK industry's emissions by scale with a threshold of 100 $ktCO_2$/year

Although the overall industrial emissions distribution seems to include a smooth representation of different scales, more granular analysis by sector uncovers significant differences. The boxplots from Figure 6 reveal those differences:

- Some sub-sectors are characterised by either large-scale plants (e.g., cement) or small-scale plants (e.g., glass), but not both.
- There are *qualitative* differences between larger plants and those at the middle or bottom of the range for subsectors that seemingly include both small- and large-scale plants. This is the case of iron and steel, oil and gas processing, and the chemical industries.

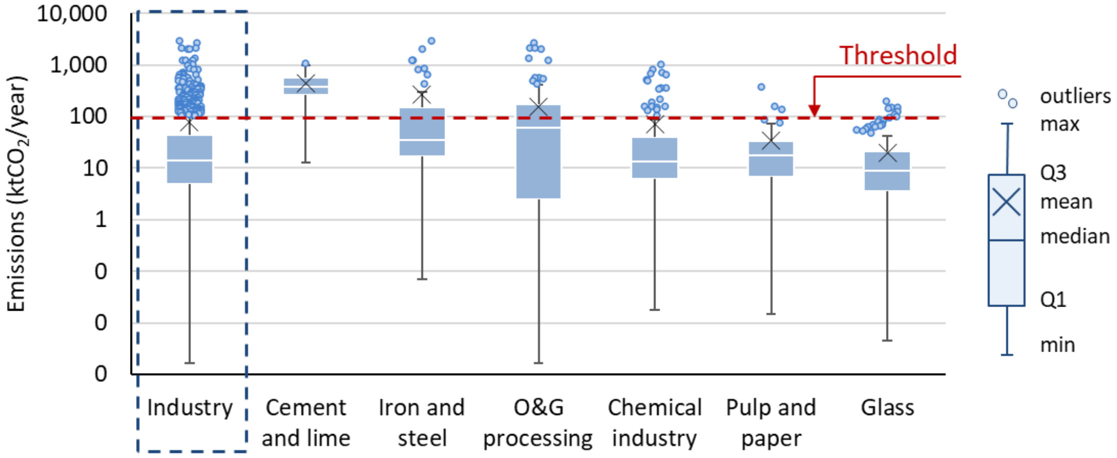


Figure 6: Boxplot of UK industrial emissions with a breakdown by sectors[9]

Indeed, distinct plants belonging to the same sector include a broad range of different processes and appliances, many of which occur mainly at either a large scale or a small scale. Table 1 illustrates some differences between large-scale and small-scale plants within each sector. Also, each process features different characteristics that may influence the techno-economics of CO_2 capture, especially for direct-fired heating processes. Hence, **the analysis will be limited to cases where carbon capture has been evaluated specifically for the required appliance or emission source**. And there is yet another implication of the qualitative differences: the comparison of small-scale capture plants with 'large-scale analogues' may only be applicable for processes that exist both on a small and on a large scale.

[9] Boxplots are a way to show the spreads and centres of a data set. The lower and upper quartiles (Q1 and Q3), the median, and the sample minimum and maximum (excluding outliers) are shown. Outliers and the mean are also included.

Table 1: Illustrative differences between small- and large-scale plants within key industry sectors

Sector	Large-scale only	Small-scale only	Small- & large-scale
Oil & gas	Integrated refineries (furnaces)	Storage and distribution terminals	Gas processing facilities
Chemicals	Petrochemical plants with high-temperature furnaces / steam crackers Ammonia plants	Speciality chemicals, plastics & pharmaceuticals with small furnaces, boilers, driers	Boilers, some direct heating appliances (furnaces/dryers)
Metals	Integrated iron & steel sites	Metal processing (rolling & finishing), casting, coating Other non-ferrous metals	Smelting of aluminium, copper, etc. Casting (furnaces)
Cement & lime	Cement kilns (combustion + process emissions)	Plants producing speciality products	Lime kilns (including "captive" lime manufacturing)
Other mineral industries	N/A	Ceramic kilns (e.g., bricks) Speciality products	Glass plants (multiple furnaces)
Paper & pulp	Integrated pulp and board mills (boilers, dryers and other sources)	Printing & publishing activities	Paper mills (boilers, dryers and other sources)
Food & drink		Breweries, distilleries (boilers, fermentation)	Various food products (boilers, ovens, dryers)
Energy from waste (EfW)			EfW plants (various fuels)

2.3 Overview of selected case studies

The analysis that has led to the working definition for small-scale carbon capture leads to the selection of four case studies to be progressed to the techno-economic assessment (TEA):

- **Gas-fired power generation**, with a focus on a natural gas combined cycle;
- **Natural gas-fired co-generation plants**;
- **Energy from Waste**;
- **Lime kilns**.

Ideally, a case study progressed to the TEA should meet four conditions:

- It must be **representative of processes that fall under the small-scale definition**;
- **CCS should be a viable decarbonisation option** for the sector, and as such it should be well studied and relatively mature;
- If no bottom-up CCS cost analysis for the sector is available, at least **the flue gas composition should be well characterised**;
- If possible, small-scale capture should be **comparable with a large-scale analogous capture plant**.

Most research on carbon capture applications has focused on sectors with no small-scale equivalents. For power generation, the focus to date has been on carbon capture from large-scale CCGT and USC pulverised coal power plants. For industry, the focus lies on carbon capture from refineries, cement, and integrated iron and steel plants. However, our engagement with industrial stakeholders has confirmed that there is an interest in carbon capture from industrial sectors with facilities belonging to our small-scale definition. The interest is greatest where deep decarbonisation with alternative technologies is not possible, due to the presence of process emissions or unavoidable emissions, such as for waste incineration.

An overview and a justification of the four case studies progressed to the techno-economic assessment are presented below.

2.3.1 Gas-fired power generation

Gas-fired power generation meets all the conditions to be progressed to the TEA. CCS for large-scale CCGT power plants is an active field of research, and capture technologies designed for them could potentially be downscaled for smaller CCGTs, and eventually for OCGTs too. Whilst the flue gas from OCGTs has a similar composition, OCGTs and CCGTs have differences in their operation profiles, generation efficiency – and hence waste heat availability –, and eventual process integration with a capture plant. These differences could introduce modifications to the capture plant design. We have progressed small-scale CCGT plants to the techno-economic assessment. Additionally, this enables the comparison with its much-studied large-scale analogue.

2.3.2 Natural gas-fired co-generation

Co-generation, or combined heat and power (CHP), plants are located where there is a need for both electricity and thermal energy. Thermal energy might be needed for district heating or for industrial processes. Because, unlike electricity, the thermal energy is used locally, CHP plants are typically smaller in size than CCGT plants. There are different CHP configurations. One of the most common configurations is a steam boiler with a steam turbine. Steam produced in a boiler is used to turn a turbine that runs a generator, producing electricity. Steam that leaves the turbine can be used to provide thermal energy.

From the perspective of the capture plant there is little difference between industrial boilers and CHP plants. Boilers are a common appliance present in multiple industrial sectors, spanning a very broad range of scales. Hence, assessing capture from a CHP plant can be extrapolated to capture from boilers. Moreover, whilst there is little literature on capture plants for CHP plants or industrial boilers, the flue gas composition is similar to the well-characterised natural gas-fired power generation.

2.3.3 Energy from waste

Energy from Waste (EfW) plants serve specific collection areas, so their size varies according to the amount of treated waste. The waste composition, which affects the energy content of the waste, also varies spatially. Hence, there is a large variation in terms of thermal input and direct emissions. Whilst some plants emit over 1 MtCO_2/year, others emit well below that threshold. In effect, a recent study by the IEAGHG mentions that, compared to fossil power plants, EfW plants are too small to follow large economies of scale.[10] If the sizes are compared in terms of thermal input, EfW plants are one to two orders of magnitude smaller than large fossil fuel-fired power stations.

Carbon capture from EfW plants is in early stages of commercial deployment and has been proposed in many sites globally. Table 2 shows a non-exhaustive list of CCS projects from EfW plants. It can be seen that although the pilots to date have been small-scale, they have been deployed mostly in large-scale EfW plants – with the exception of the Saga City EfW plant. Exploring the possibilities of expanding the interest in CCS from EfW plants to small-scale plants as well is thus highly relevant.

[10] IEAGHG, 2020, *CCS on Waste to Energy*, Technical Report 2020-06.

Deployment of carbon capture at EfW plants can lead to negative emissions, tied to capturing CO_2 from waste from biogenic origin. Despite the attractiveness of CCS for decarbonising EfW plants, these are capital intensive and hence need high annual revenues from the sale of electrical or thermal energy generated. Carbon capture can negatively impact those revenues. The relevance of CCS for decarbonising the sector and the various challenges of deploying carbon capture in small-scale EfW plants justify progressing the case study for the techno-economic assessment.

Table 2: Selected CCS projects from EfW plants

Country	Plant	Emissions ($ktCO_2/y$)	Status	Captured ($ktCO_2/y$)
Netherlands	AEB Amsterdam	1,268	Feasibility study	450
Netherlands	AVR-Rozenburg	1,153	Concept study	800
Netherlands	HVC-Alkmaar Project 1	674	Ongoing (+ feasibility study)	4 (+ 75)
Netherlands	Twence-Hengelo	600	Engineering study	100
Norway	Fortum-Klemetsrud	460	FEED ongoing	414
Netherlands	AVR-Duiven	400	In operation	60
Japan	Saga City	54	In operation	2.5

2.3.4 Lime kiln

Emissions from lime production in lime kilns include combustion emissions and process emissions, resulting from the processing of raw materials rather than from the combustion of fossil fuels. Process emissions can represent more than two-thirds of a plant's total emissions.[11] As the process emissions are unavoidable under current production technologies, CCS offers the biggest potential reduction of the carbon intensity of lime. This has spurred interest in CCS for the lime and cement sector.

One of the most common kiln technologies, and the most energy efficient, is the parallel flow regenerative kiln (PFRK). The operating scale of a PFRK ranges from 100 to 600 tonnes of lime per day,[12] with an average of 300 tpd validated through stakeholder engagement. This is equivalent to around 40 to 240 $ktCO_2$/year – and an average of 120 $ktCO_2$/year that is very close to the previously defined threshold. Whilst some lime plants operate a single lime kiln, many plants operate several independent kilns. Thus, the lime plant could be classified as a large-scale emitter composed of several small-scale sources. Capturing carbon from lime kilns presents an additional challenge: because lime prices per tonne are relatively low and its production is CO_2 intensive, the cost of carbon capture can have a strong impact on product prices if not adequately supported.

Because lime kilns are examples of a small-scale capture application and CCS is highly relevant for the sector, we progress lime kilns to the techno-economic assessment. However, as the largest lime kilns are limited to around 240 $ktCO_2$/year, a comparison with a large-scale analogue will be of lesser interest.

[11] Assuming complete conversion of limestone into lime, the stoichiometric decomposition of limestone into lime amounts to 785 kgCO_2 per tonne of lime. In comparison, average combustion emissions are 322 kgCO_2 per tonne of quicklime according to European Lime Association, 2014, *A Competitive and Efficient Lime Industry*.
[12] LEILAC, 2021, *LEILAC Technology Roadmap to 2050*.

3 Capture technology options for small-scale plants

Carbon capture from small-scale applications suffers from a significant knowledge gap. There is limited available information and most literature – and technology developers – focuses on large-scale power generation or on industrial sites like integrated iron and steel plants or cement plants that do not feature small-scale plants. Cost modelling is typically done for capture units on a mega-tonne scale. For post-combustion chemical absorption technologies there is good availability of bottom-up cost analysis, but other capture technologies are often analysed from a high-level perspective.

Scale is discussed only in a few sources. Most prominently, the Global CCS Institute has quantified the impact of scale on the cost of capture for a solvent-based post-combustion process.[13] Despite this valuable contribution, the central cost analysis is still done for large-scale carbon capture and is then scaled down. No study to date deals quantitatively with the scaling of capture costs from a bottom-up perspective. Consequently, high-quality bottom-up information on capture costs is only available for large-scale capture units that are one or two orders of magnitude larger than our working definition of small-scale. Some of the data that is available, as results from the Test Centre Mongstad, does not reflect a commercial plant but a very large pilot. For one carbon capture application in particular, biogas upgrading, there is operational experience on small-scale applications. However, biogas upgrading cannot be directly compared with post-combustion capture. In biogas, methane content can range from 35% to 70%, and CO_2 content from 15% to 40%.[14] This is opposed to post-combustion capture where CO_2 is separated from nitrogen as the main constituent of the flue gas. **The availability of information implies a need to scale down cost estimates for the techno-economic assessment**. The approach for scaling down will be presented in Section 4.1.

The capture technologies that are best suited for large-scale capture are not necessarily the best suited for small-scale capture. The physical basis of economies of scale, covered in Box 1, heavily impact some capture technologies. Capture technologies involving high pressures or high temperature variations, such as cryogenic distillation or oxyfuel combustion, will likely struggle to scale down for small-scale capture. Moreover, because the costs of some equipment, such as pressure vessels or pumps, are weak functions of the scale of the equipment, processes that need multiple pieces of equipment can become expensive at small scales. As the scale is reduced, the increase in specific capital costs is larger than the expected drop in efficiency and, consequently, capital costs represent a larger share of the levelised cost of capture at a small scale. Therefore, capital-intensive capture technologies will scale down worse than others.

Other factors, related to the industrial processes that are more typical at smaller scales, contribute to explaining why the most suitable separation technology is likely to vary with scale. Waste heat that can be used for carbon capture at little additional cost for large-scale capture could not be available at small scales. This, together with the fact that energy rates tend to be higher for small industrial users than for large users, can result in higher specific energy costs per tonne of CO_2 for small-scale capture. Many small-scale plants will either be of dispersed nature – i.e., not within industrial clusters that could access CCS hubs in the future –, or closer to population centres than large-scale plants. If dispersed plants do not get access to T&S infrastructure built around anchor emitters, CCU technologies become more attractive even if the *capture* cost comes at a premium.[15] Capture plants close to population centres will be subject to heavier public scrutiny. Thus, capture technologies that can avoid some of the

[13] Global CCS Institute, 2021, *Technology Readiness and Costs of CCS*. It is interesting to note that the Global CCS Institute analysis leads to the statement that, to minimise capture costs, the capacity of CO_2 capture units should be at least 400 to 450 ktCO_2/year.
[14] Sun et al, 2015, 'Selection of appropriate biogas upgrading technology: a review of biogas cleaning, upgrading and utilisation', *Renewable and Sustainable Energy Reviews*, 51.
[15] Few utilisation technologies lead to permanently stored CO_2. Those that do, such as mineralisation, have a relatively low TRL and will not be analysed within this study.

environmental concerns related to carbon capture, notably amine emissions, will have a comparative advantage. In addition, it is expected that compact plants to reduce land requirements will be increasingly important for small-scale sites with a smaller balance of plant, although this importance varies by region.

Box 1 – Economies of scale

Among the multiple determinants of economies of scale there is a physical basis that impacts engineering design. That basis explains why rotating equipment like pumps and compressors have lower efficiency at small scales, processes tend to have a relatively higher heat loss, and larger column specific volumes are needed. Higher unit capital costs are required to balance the drops in process efficiencies.

- Heat losses occur when heat is transferred from an outer surface to its surroundings. As pipes, tanks or vessels are scaled down the ratio between their surface and their volume varies similarly to the square-cube law. This means that **for smaller scales heat losses are relatively higher**, because the ratio between surface and volume is higher.
- Leakage negatively affects compression efficiency. At a small scale the relative length of the seals is longer, which leads to **higher leakage**. Capture technologies relying on high-pressure processes will not scale down as well as those that do not require compression.

Integration costs also show high economies of scale. Some of the main cost determinants of the capture plant integration are the piping, fitting and equipment connecting the processes and the main plant downtime. As the piping length has a much higher impact on total costs than its area, total costs are a weak function of scale.

Procurement leverage linked to large-scale plants is also a factor that leads to economies of scale. Although nothing changes from a physical perspective, larger scales bring greater bargaining power.

Transport and storage costs are strongly affected by economies of scale as well. However, small-scale plants could benefit from the development of CCS hubs around large-scale anchor emitters. Small-scale plants within the hub can then use the pipeline without incurring much higher unit costs.

3.1 Overview of key carbon capture technologies

A high-level analysis of capture technologies informed the selection of those that are most suitable for small-scale capture, focusing on technologies that have a TRL from 6 to 9. Despite the abundance of literature on each capture technology, the availability of cost data on small-scale capture for different applications is poor. The capture process performance resting on patented processes and solvents, developers are generally unwilling to share more than high-level data. Furthermore, many sources report reference capture costs, but lack of granularity in the cost composition and the dependency on site-specific conditions impede direct comparisons. It should also be noted that whilst certain capture technologies may have a high TRL for some applications there is no direct transferability from one sector to another. The TRL should be measured for specific applications, which lowers the TRL of the selected technologies for typical small-scale industries. For example, there is no TRL 8 or 9 capture technology for glass furnaces, even if post-combustion chemical absorption is at TRL 9 for coal-fired power generation.[16]

Amine-based post-combustion capture is the current benchmark capture technology. It is the most mature capture technology with a TRL 9 for power applications, having been tested at commercial scale with a few live applications on a large scale. However, its applicability to small-scale carbon capture is challenged by its high capital cost and heat requirements. This has various implications. First, as the scale is reduced, capital costs represent an even larger share of the levelised cost of capture. Second, cost-effective chemical absorption relies on a low-cost heat supply strategy. If insufficient waste heat is available an additional ad-hoc boiler would be needed, which might often be the case for small-scale applications. This leads to a capital cost increase and additional emissions that need to be captured as well.

Advanced solvents are under development to reduce the regeneration heat duty and improve the overall performance. Some of these developments are already at a commercial scale and offer modular or semi-modular solutions, which could potentially be applicable to small-scale capture.

The high capital cost and energy requirements of amine-based capture lead to the consideration of other carbon capture technologies which could be better suited for small-scale capture. We have identified three alternatives to traditional amine-based capture, as shown in Table 3:

- **Advanced chemical absorption**;
- **Membrane separation**;
- **Molten carbonate fuel cells (MCFC)**.

Whilst a full description of the technologies can be found elsewhere,[17] the next section will give an overview of the technologies considered to be particularly suitable for small-scale applications. Pre-combustion capture technologies or oxyfuel combustion technologies are favoured on very large scales and have not been progressed further.

[16] Roussanaly et al argue that "the definition of TRLs requires an assessment of the overall system into which a new technology is placed. Thus, the TRL of a capture technology must be defined and evaluated in the context of a specific application, with new applications having lower TRLs." Roussanaly et al, 2021, 'Towards improved cost evaluation of Carbon Capture and Storage from industry', *International Journal of Greenhouse Gas Control*, 106.
[17] For instance, see IEAGHG, 2019, *Further Assessment of Emerging CO_2 Capture Technologies for the Power Sector and their Potential to Reduce Costs*, Technical Review 2019-09.

Table 3: Capture technologies with the highest potential to be used for small-scale capture

Technology class	Technology	Sectors of applicability	TRL[18]	Date avail. commercially	Scale of demonstration	Data availability	Small-scale suitability	Developers
Chemical absorption	Amines	Industry, power	7-9	Today	1-1,500 $ktCO_2/y$	High	Medium	Carbon Clean, Shell, MHI, Toshiba, Entropy, etc,
	Non-amine based solvents	Industry (hard to abate), power	6-7	<2025	1-10 $ktCO_2/y$	Medium	High	C-Capture, CO_2 Solutions, CO_2 Capsol
Membrane separation	Polymeric membranes	Industry, power (>8% CO_2)	5-7	<2025	1-50 $ktCO_2/y$	Medium	High	MTR, Air Liquide
Fuel cell	Molten carbonate fuel cells	Power generation	6	<2030	1-15 $ktCO_2/y$	Low	High	FuelCell Energy

[18] TRL assigned based on Element Energy's assessment. TRLs will vary depending on specific applications and technology providers.

3.1.1 Chemical solvent-based absorption

In a chemical absorption process, gaseous CO_2 forms chemical bonds with chemical agents in solution. The solvent is then regenerated by raising its temperature to release CO_2. Commercial or nearly commercial chemical solvent-based absorption technologies typically use amine-based solvents. The most well-known conventional solvent is MEA, used in an aqueous solution, but many alternatives exist. Advanced chemical absorption replaces MEA with advanced amines, non-amine and non-aqueous solvents, and catalytic enzymes. The aim is to reduce regeneration energy requirements and corrosivity, and to improve the absorption rate and stability. The most mature processes are the Shell Cansolv process and the MHI KM-CDR process.

Advanced solvents can present significantly lower energy requirements for regeneration, can mitigate the environmental impact from atmospheric emissions – particularly non-amine solvents – and solutions are available from multiple developers. Some of these technologies aim at reducing the capital cost of capture plants. In particular, the rotating packed bed concept[19] or the rotating liquid sheet contactor are of interest. Technologies such as C-Capture's amine-free absorbent or Saipem's enzyme-enhanced potassium carbonate solution enable a lower regeneration temperature. Whilst the heat rate does not change significantly compared to other technologies, the possibility of using hot water rather than steam for regeneration is an advantage particularly suited for small-scale plants, which are likely to have lower-grade heat options. Advanced solvents, however, can show higher degradation rates and can increase the release of amine compounds to the atmosphere, which could cause health and regulatory issues. A more stringent pre-treatment of the flue gas to reduce degradation could increase costs.

Another alternative solvent is hot potassium carbonate with a pressurised absorption step. In the technology developed by CO_2 Capsol, a pressure drop in the stripper column together with steam are used to release CO_2 from the solvent. Steam for the stripper is generated from heat recovery after the flue gas compression step. This can make the technology attractive to avoid site-specific heat integration challenges or for use cases where there is limited waste heat available.

Despite the potential for advanced solvents and processes to lower costs, chemical solvent-based absorption is still a capital-intensive technology. As such, it benefits from economies of scale and costs are likely to escalate at smaller scales. Moreover, many of the proprietary solvent blends have not been tested under a broad range of flue gases for long time periods.

3.1.2 Membrane separation

Membranes are a barrier over which some constituents of a gas mixture are more mobile than others, i.e., some components of the mixture pass through the barrier at a faster rate. The driving force for the separation is the partial pressure difference across the membrane. As a result, capture costs strongly increase with the capture rate. Whilst membranes can be organic or inorganic, most membranes evaluated for post-combustion capture are polymeric. For membranes to be economically attractive for CO_2 separation, they should present high permeability – to reduce electricity consumption – and high CO_2/N_2 selectivity – to obtain a CO_2 product stream of high purity. There is a trade-off between permeability and selectivity, as optimising the permeability involves reducing the CO_2 stream purity. In order to obtain CO_2 at the high purity requirements needed to inject it into the T&S network, a CO_2 purification process using liquefaction needs to be added to the system before injection. In other cases, where CO_2 is utilised rather than stored, high purity might not be needed.

Membrane Technology and Research (MTR) commercialises and continues to develop high-permeance polymeric membranes. Unit capture costs for their Polaris Gen-2 membrane are minimised by operating at capture rates between 50 and 60% – CO_2 capture rates up to 90% can be achieved at

[19] Commercialised by Carbon Clean as their CaptureCC technology.

a higher cost. The purity of the CO_2 stream before the CO_2 condensation column is reportedly greater than 85%.

Membranes are particularly suited for small-scale plants because they are modular by nature. In fact, under a given partial pressure difference, the mass transfer scales linearly with the membrane surface area. In addition, they have low energy requirements and can be left running unattended for extended periods. Another advantage is that it results in no amine emissions, something particularly appealing for small-scale sites near population centres. Despite these advantages, membrane separation faces some challenges to enable commercial deployment at small-scale sites. Whilst energy requirements are lower, the separation process is run by electricity and will not benefit from low-cost waste heat. Also, the membranes themselves are modular, but the rotating equipment – blowers and pumps – and the CO_2 condensation column will be affected by economies of scale. Moreover, the technology has a lower TRL than chemical absorption.

3.1.3 Molten carbonate fuel cell

A molten carbonate fuel cell (MCFC) uses electrochemical membrane technology to capture CO_2 and produce power simultaneously. By using a source of hydrogen, normally by in-situ reforming of natural gas at the anode, the electrochemical potential acts as the driving force for separation. Carbonate ions are formed at the cathode where CO_2, supplied from flue gas, reacts with O_2. The carbonate ions then travel to the anode where they are reduced to H_2O and CO_2, which can be separated from the anode exhaust by a cryogenic purification step. MCFCs can be integrated into natural gas-fired power plants or used for CHP plants. The biggest developer of MCFCs is FuelCell Energy. They have commercialised multiple MCFC power plants, with power output ranging from 1.4 MWe to 3.7 MWe, where CO_2 constitutes 70% of the anode exhaust. Their new development, SureSource Capture, is aimed at retrofitting power plants or industrial boilers.

MCFCs are attractive for small-scale applications because of their modularity and because the capture cost is decoupled from the heat supply strategy. Hence, they can be particularly relevant for CHP plants or where little waste heat is available. The technology, however, has a lower maturity with a TRL of 6, is capital intensive, and might encounter challenges related to the cell durability – requiring very clean flue gases.

3.2 Trends in small-scale capture

Our analysis of trends in small-scale capture was validated by engagement with technology developers and industrial partners. Up to now, the key market focus has been on capture from large-scale power generation. Two trends challenge this focus: there is an increasing interest from large-scale industrial emitters, with refineries, integrated iron and steel sites, and cement plants leading the commercial interest, and small-scale emitters are slowly beginning to emerge as potential clients for technology developers. The focus on large-scale applications is however still dominant. Most technology developers have identified that upscaling above 1 $MtCO_2$/year is their main goal, and even the development of smaller plants revolves around large-scale emitters. Industries willing to deploy CCS as a decarbonisation technology are focused on flagship projects. Until they start operating capture units in large sites, they consider that carbon capture from smaller, dispersed sites is a distraction. **The trend towards capture from small-scale sites might be deferred into the second half of the 2020s**. Despite this, technology developers are preparing to meet future demand growth from small-scale emitters.

The development of capture plants for small-scale emitters combines different strategies:

- **Modularisation**, to offset the loss of economies of scale by transferring them to the manufacturing process;

- **Automation and compact design**, to diminish the need for staffing and to reduce land requirements;
- **Process intensification**, to mitigate the physical economies of scale that negatively mass transfer processes.

A trend towards the modularisation of capture plants is leading development efforts. Pioneered by Aker Carbon Capture and Carbon Clean,[20] the interest in modular plants has expanded and now includes developers focused on large-scale applications such as Shell Catalysts and Technologies. Modular plants are manufactured off-site using mass production techniques, typically integrated with shipping containers for the smaller components. Hence, the loss of economies of scale from small-scale projects can be partially offset, as economies of scale are transferred to the manufacturing process. As explored by the Global CCS Institute,[21] modular carbon plants can also help to reduce costs through standardised plant foundations, standardised designs, automated operation, and modular packaging, reducing on-site construction time and costs. The containerised approach to capture plants, however, should not be mistaken with a fully modular design. Important plant components as absorber columns would likely need to be modularised differently.

The standardisation of capture plants involves trade-offs between high performance and low manufacturing and engineering costs. The way in which developers deal with those trade-offs is nuanced. Some developers prefer to design custom-engineered modular solutions, where the capture process is optimised on a case-by-case basis rather than mass produced. Whilst the plant components may be skid-mounted and containerised, the degree of standardisation is limited. Other developers are focused on the design of fully standardised solutions. Under such an approach, a certain loss of performance is accepted, and components may be slightly over-designed to allow them to meet different operating conditions and still achieve high capture rates. Operating parameters such as the solvent concentration or the rotating equipment speed can adapt to site conditions. The full benefits of reducing capital costs through modularisation are reaped, although the operating costs may result higher.

The trend towards modularisation is an enabler for the deployment of small-scale capture plants. However, this is not the primary focus of technology developers. Developers are not ready to deploy commercial capture plants below 10 ktCO_2/year at any time soon, and most of them focus on solutions above 25 ktCO_2/year. The standardisation of capture plants is often presented as a strategy to lower capture costs for power generation or industrial sites with a scale of several hundred thousand tonnes of CO_2 per year. To this effect, modularisation is offered as a possibility to enable a gradual deployment of carbon capture within each site, allowing to space capital commitments and to reduce deployment risks. Moreover, modular units may enable faster reactions to changes in market conditions.

Automation and compact design are often pursued together with modularisation. Hiring skilled labour to operate capture plants is more challenging for small-scale sites. Remote or automated operation is hence particularly relevant for them. Similarly, small-scale sites closer to population centres are more likely to have little land available for additional facilities. The compact design offered by containerised solutions stands to benefit them to a greater degree.

Finally, process intensification is a way of reducing the size of equipment, leading both to lower capital costs and a more compact design. An example is Carbon Clean's CycloneCC. The absorber column, most often with a packed bed design, is replaced with a rotating packed bed design. The mass transfer process between the solvent and the flue gas is aided by the centrifugal force within the absorber.

[20] Aker Carbon Capture markets its "Just Catch" modular capture plants with two size offerings – 40 and 100 ktCO_2/year. Carbon Clean commercialises semi-modular solutions of various sizes and has more recently launched CycloneCC, a fully modular design targeting sizes from 10 tpd to 300 tpd (3.7 to 110 ktCO_2/year).
[21] Global CCS Institute, 2021, *Technology Readiness and Costs of CCS*.

Carbon Clean claims that this leads to a reduction in the size of the absorber column by a factor of 10 as well as to a 50% reduction in the plant's footprint.

4 Techno-economic assessment

The techno-economic assessment (TEA) aims to elucidate the economic viability of CO_2 capture on small-scale applications. It also explores how differences between small-scale and large-scale applications impact that viability. The TEA focuses on post-combustion chemical solvent-based separation for four case studies. The performance of two different solvents, and slight variations within each case study, are tested. The TEA builds on a set of key inputs:

- **CAPEX data**, scaled down from available data for large-scale capture plants;
- **OPEX data**, derived from in-depth literature research;
- **Energy cost**, obtained from short- and long-term price projections.

The TEA quantifies three sets of costs:

- **The cost of CO_2 captured**.
- **The cost of CO_2 avoided**.
- **The corresponding increase in the cost of products and services**.

After presenting the methodology for the techno-economic assessment, including the approach to energy costs, each case study is introduced. Results are then displayed. These include the thermodynamic and economic performance for each case study, accompanied by a sensitivity analysis on the most relevant input parameters. The policy assessment is presented in Chapter 6.

4.1 Methodology

The thermodynamic performance is evaluated by electrical energy efficiency (η_{elec}) and total efficiency (η_{total}), which is the sum of electrical and thermal energy efficiency ($\eta_{thermal}$); where W_{elec} and $Q_{thermal}$ are the net electrical and thermal energy output, respectively, and $\dot{m}$ and LHV are the mass flow rate (kg/s) and lower heating value (MJ/kg) of the fuel gas into the capture plant. Equations (1) to (3) show the definition of the efficiencies.

$$\eta_{elec} = \frac{W_{elec}}{\dot{m}_{fuel\ gas} \times LHV_{fuel\ gas}} \tag{1}$$

$$\eta_{thermal} = \frac{Q_{thermal}}{\dot{m}_{fuel\ gas} \times LHV_{fuel\ gas}} \tag{2}$$

$$\eta_{total} = \frac{W_{elec} + Q_{thermal}}{\dot{m}_{fuel\ gas} \times LHV_{fuel\ gas}} \tag{3}$$

Table 4 presents key assumptions for the thermodynamic evaluation. It is worth noting that for the cases integrated with the steam cycle, it is considered that the entire heat requirement for the regeneration process (stripper reboiler) is provided from the steam cycle. Hence, this is shown as steam turbine losses.

Table 4: Considered assumptions for the technical analysis derived from reference[22]

	Large scale	Small scale	High CO_2 concentration case (kiln)	Unit
Blower consumption	0.70	0.11	-	MJ_{elec}/kg_{CO2}
Pump consumption	0.08	0.10	0.08	MJ_{elec}/kg_{CO2}
CO_2 compressor consumption	0.31	0.38	-	MJ_{elec}/kg_{CO2}
Steam turbine losses (conv)	1.00	1.16	-	MJ_{elec}/kg_{CO2}
Steam turbine losses (adv)	0.78	0.86	-	MJ_{elec}/kg_{CO2}
Stripper heat requirement (conv)	3.70	4.30	3.44	MJ_{elec}/kg_{CO2}
Stripper heat requirement (adv)	2.90	3.20	2.56	MJ_{elec}/kg_{CO2}

The CO_2 specific emissions (E_{CO2}) indicates the specific consumption per unit product (i.e. kWh in case of energy) and the specific primary energy consumption for CO_2 avoided *(SPECCA)* is defined as the consumption of primary energy required (in MJ_{LHV}) to avoid the emission of 1 kg of CO_2, while producing the same amount of product. They are calculated as indicated in Equations (4) and (5) below.

$$E_{CO_2}\left[\frac{kg_{CO_2}}{MWh}\right] = \frac{\dot{m}_{CO_2} \times 3600}{W_{elec} + Q_{thermal}} \tag{4}$$

$$SPECCA\left[\frac{MJ_{LHV}}{kg_{CO_2}}\right] = \frac{\left(\frac{1}{\eta_{total,capture}} - \frac{1}{\eta_{total,no\ capture}}\right)}{E_{CO_2,no\ capt} - E_{CO_2,capture}} \tag{5}$$

The economic performance is assessed in terms of Equation (5), cost of CO_2 capture (CCC, $\$/t_{CO2}$) as in Equation (6), and cost of CO_2 avoided (CCA, $\$/t_{CO2}$) – which quantifies the average cost of *avoiding* a tonne of CO_2 net of the additional energy and carbon-intensity of the capture process – as in Equation (7).

$$CCC = \frac{Total\ annualised\ cost\left[\frac{\$}{y}\right]}{CO_{2_{Captured}}\left[\frac{t_{CO_2}}{y}\right]} \tag{6}$$

$$CCA = \frac{\Delta\, Cost_{Product}\left[\frac{\$}{X}\right]}{E_{CO_2,ref}\left[\frac{t_{CO_2}}{X}\right] - E_{CO_2,capture}\left[\frac{t_{CO_2}}{X}\right]} \tag{7}$$

[22] Sánchez Fernández et al, 2014, 'Thermodynamic assessment of amine-based CO_2 capture technologies in power plants based on European Benchmarking Task Force methodology', *Fuel*, 129, 318-329.

The total annualised cost (TAC) is only associated with implementing the CO_2 capture technologies (post-combustion). It, therefore, represents the difference between the TAC of the entire plant with and without carbon capture implemented. The TAC is calculated by considering the total capital requirement for the CO_2 capture plant (TCR), the fuel cost *(C_{fuel})*, variable *($V_{O\&M}$)* and fixed *($F_{O\&M}$)* operating and maintenance costs to operate the plant with carbon capture, shown in Equation (8).

$$TAC\left[\frac{M€}{y}\right] = TCR \times ACCR + C_{fuel} + V_{O\&M} + F_{O\&M} \tag{8}$$

The equipment purchase and installation costs (*C_B*) were calculated based on reference cost data from the literature (Table 5) using Equation (9) where C_A is the cost of the reference component with the capacity of Q_A and f is the scaling factor.

$$C_B = C_A \left(\frac{Q_B}{Q_A}\right)^f \tag{9}$$

Table 5: Scaling parameters for the component purchase and installation cost[23]

Component	Scaling factor	C_A (M$)	Q_A (Mt/y)	f
CO_2 capture unit (MEA)	CO_2 mass flow rate (Mt/y)	110.1	1	0.65
CO_2 compressor and condenser	CO_2 mass flow rate (Mt/y)	15.7	1	0.65
Boiler*	Generated steam flow rate (kg/h)	0.328	20000	0.81
*This cost is only purchase cost. The installation cost is 300% of the purchase cost				

The total equipment cost ($\boldsymbol{TEC}$) is calculated as in Equation (10).

$$TEC = \sum_{i}^{n} C_{B,i} \tag{10}$$

Total plant cost (TPC) comprises TEC, engineering fees, and contingencies. Total capital requirement (TCR) comprises TPC and owner costs. The main economic assumptions used for component purchase cost calculation are presented in Table 6. The reference cost C_0 and plant size Q_0 are not available in literature nor manufacturer have provided data for the scale considered in this study and therefore their estimation is subject to the accuracy associated to non-conventional equipment. A sensitivity analysis has been carried in this study considering -10% and +20% CAPEX change to mitigate this issue (Table 8).

[23] Yang et al, 2021, 'Carbon capture and biomass in industry: A techno-economic analysis and comparison of negative emission options', *Renewable and Sustainable Energy Reviews*, 144 (2021) 111028.

Table 6: Techno-economic assessment assumptions[24, 25]

	Unit	Value
Total plant cost (TPC)	%TEC	130
Total capital requirement (TCR)	%TPC	110
Fixed operating and maintenance cost	%TCR	1
Variable operating and maintenance cost	%TCR	2
Scaling factor	-	0.67
Capacity factor	%	85
Plant lifetime	year	25
Project interest rate	%	10

The annualised capital charge ratio ($\boldsymbol{ACCR}$) is defined using Equation (11), considering the project interest rate ($\boldsymbol{r}$) and project lifetime ($\boldsymbol{n}$).

$$ACCR = \frac{r(1+r)^{\,n}}{(1+r)^{\,n} - 1} \tag{11}$$

The incremental cost per unit of product ($\Delta cost_{product}$) is considered as the ratio of TAC associated with the implementation of the CO_2 capture technology and the amount of products. The TAC includes the annualised capital cost of the CO_2 capture plant and the costs associated with utility consumptions, variable and fixed costs to run the CO_2 capture plant.

$$\Delta Cost_{product}\left[\frac{\$}{X}\right] = \frac{TAC_{capture}\left[\frac{\$}{y}\right]}{production\ rate_{capture}\left[\frac{X}{y}\right]} \tag{12}$$

Energy prices

Energy prices are a key input for the techno-economic assessment. The cost of electricity, natural gas and heat are central components of the operational expenditure. The energy prices along the entire lifetime of the investment underpin the economic case for carbon capture. Hence, it is necessary to work with energy price projections. Because energy price projections are inherently uncertain, we have tested the influence of a broad range of energy prices as sensitivities.

The cost of heat for solvent regeneration depends on the heat supply strategy and waste heat availability. Different heat supply strategies, ordered from lowest to highest cost, include using excess heat from industrial processes (low cost option), extracting steam from a low-pressure turbine (medium

[24] Ibid.
[25] Khallaghi et al, 2022, 'Techno-economic assessment of blast furnace gas pre-combustion decarbonisation integrated with the power generation', *Energy Conversion and Management*, 255.

cost option), or utilising a natural gas or electric boiler (high cost option).[26] The cost of the heat supply was linked to the natural gas or electricity prices for each case study.

Two different counterfactual prices of electricity could be relevant, depending on the emitter:

- The **wholesale market price of electricity** is the cost faced by power generators due to lost revenues. The lost revenues are caused by the energy penalty of implementing carbon capture, as the power output decreases.
- The **price of electricity for industrial users** is the cost faced by industrial users to operate pumps, blowers, the CO_2 compression stage, or to regenerate the solvent if using an electric boiler. In this case, the energy for the capture unit is supplied externally.

Natural gas prices are expressed on a higher heating value (HHV) basis and reflect the wholesale price. This is likely to be an underestimation of the actual cost faced by power producers and industries, which will be higher than the wholesale price. However, the difference is within the range of uncertainty of the price projections.

Long-term energy price projections include the IEA World Energy Outlook,[27] an EU Energy Outlook by Energy Brainpool,[28] or the Annual Energy Outlook from the US Energy Information Administration (EIA).[29] As these projections have a 2050 horizon, they cover a 25-year lifetime for investments made today. Shorter-term price projections generally have a higher spatial resolution and have been used for the first years of operation. Most price projections – short- and long-term – have been released before the global instability in energy prices that has been present since mid-2021 and that worsened with the Russia-Ukraine conflict. Its long-term effects on global energy prices are not yet fully understood and are therefore not included in this analysis.

Current energy prices[30] have a higher geographic and categorical granularity and are used in two different ways. First, they are utilised to adjust the starting point of the projections. Second, its use allows the introduction of a source of differentiation between wholesale and industrial electricity price projections. Indeed, electricity price projections either report the wholesale price, as in the EU Energy Outlook, or the price for final users, as in the EIA Annual Energy Outlook. By assuming that the price difference between wholesale and industrial electricity prices will remain constant, current prices allow to infer one from the other.

Figure 7 illustrates the energy prices used for the techno-economic analysis for the Netherlands. It results from combining insights from current prices, national short-term projections and long-term projections. Annual energy prices for the Netherlands and for the other regions focus of this study are presented in Appendix 8.2.1.

[26] Roussanaly et al, 2021, 'Towards improved cost evaluation of Carbon Capture and Storage from industry', *International Journal of Greenhouse Gas Control*, 106. The order depends on the ratio between electricity and natural gas prices.
[27] IEA, 2021, *World Energy Outlook*.
[28] Energy Brainpool, 2019, *EU Energy Outlook 2050*.
[29] Energy Information Agency, 2021, *Annual Energy Outlook*.
[30] Current energy prices refer to the most up-to-date consolidated prices (prior to mid-2021).

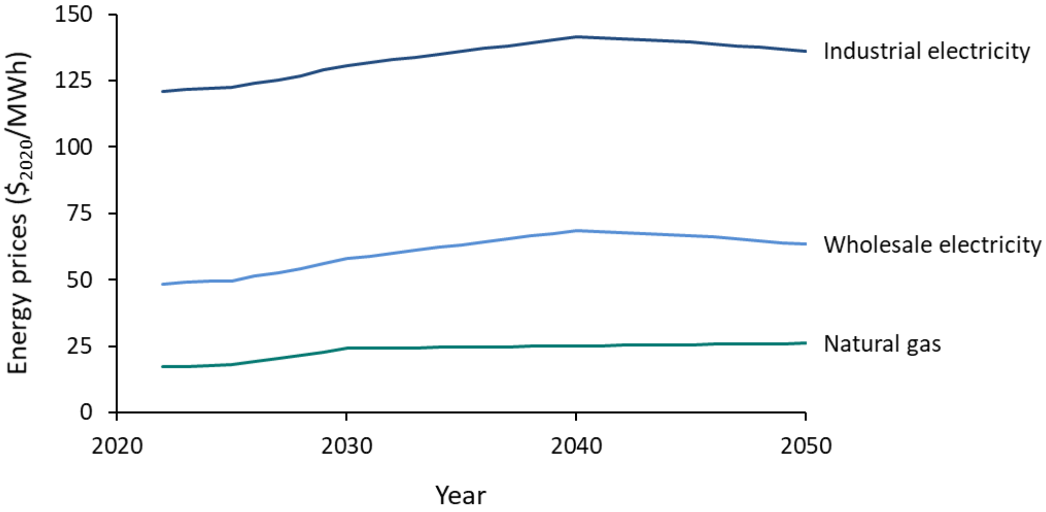


Figure 7: Energy prices projection for the Netherlands

The energy prices are incorporated into the techno-economic assessment and for the modelling of policies and incentives in two different ways. They can be expressed as an equivalent energy price, averaged over the lifetime of the investment, or as annual energy prices in a cash flow.

As covered above, the total annualised cost requires an annual energy cost as an input. The impact of energy prices on the capture cost, however, will naturally vary along the lifetime of the investment. Other cost components, such as the performance of the capture unit or the operational and maintenance costs, can be assumed to remain constant in real terms. Hence, energy prices need to be expressed in an equivalent averaged energy price. The equivalent energy price is obtained by averaging the discounted energy prices following Equation (13), where C_{eq} and C_i represent the equivalent and annual energy costs – be it wholesale electricity, industrial electricity, or natural gas price – for the lifetime N.

$$C_{eq} = \frac{\sum_{i=1}^{N} \frac{C_i}{(1+r)^i}}{\sum_{i=1}^{N} \frac{1}{(1+r)^i}} \tag{13}$$

As it can be seen from Equation (13), the equivalent energy cost depends on the discount rate. Table 7 shows the equivalent energy costs for a range of discount rates. There is only a slight sensitivity to it, and the uncertainty on energy price projections is certainly higher than the effect of utilising different discount rates. Still, the link between the discount rate and equivalent energy prices will be reflected when varying the discount rate as part of the sensitivity analysis in Section 4.3.

Table 7: Equivalent energy cost dependence on the discount rate

Discount rate	Wholesale electricity ($/MWh)	Industrial electricity ($/MWh)	Natural gas ($/MWh)
3.5%	59.49	132.31	22.82
10%	56.82	129.65	21.73
12%	56.11	128.94	21.43

Sensitivity analysis

A supplementary sensitivity analysis has been carried out for the selected cases on the most relevant input parameters, as laid out in Table 8. The sensitivity range for the discount rate varies from 3.5%, adopted to represent a social discount rate,[31] to 12%, representative of riskier investments. A small perturbation to the 90% capture rate was introduced to assess the connection between capture costs and capture rate (±3%). As for the CAPEX, a cost reduction of 10% and a cost escalation of 20% were considered to take into consideration the uncertainty associated to small scale plant manufacturing and to the scaling factor. A cost range of -10%/+20% covers a scaling factor from 0.55 to 0.75. The energy costs were tested under larger perturbations because of the high uncertainty linked to future energy prices. The sensitivity considers ±50% variations in the central cost of natural gas and electricity. The heat cost depends directly on the fuel price and on the heat supply strategy. For the central case, it is assumed that heat is sourced from LP steam, with a cost of approximately 55% of the cost of the fuel. The latter assumption depends on how much the value of energy decreases by reducing the temperature level of heat availability from combustion temperature to low-pressure steam.[32] The highest cost of heat, assumed to be equal to the cost of fuel, assumes that there is no heat integration and heat is supplied by a natural gas boiler. The lowest cost represents the use of waste heat with very low cost.

Table 8. Assumptions considered for the sensitivity analysis

Utilities	Low	Medium	High
Discount rate	3.5%	10%	12%
Capture rate	87%	90%	93%
CAPEX	-10% reference	Reference	+20% reference
Fuel Price ($/GJ)[33]	3.0	6.0	9.1
Heat ($/GJ)	20% of the equivalent High Heat	55% of the equivalent High Heat	(as fuel price)
Wholesale Electricity ($/MWh)[33]	28.4	56.8	85.2
Industrial Electricity ($/MWh)[33]	64.8	129.7	194.5

It is worth mentioning that the discount rate affects the cost of both fuel and electricity. However, in all the discussed cases (except for the lime kiln), as no excess fuel is needed, the effect of changes in fuel cost has not been taken into account as this report evaluated the impact of capture plant-only integration.

The CO_2 capture rate for this study has been limited in the range of 87% to 93%. Although higher capture rates have been achieved with advanced solvents they are still at bench scale. Since energy cost associated to solvent regeneration are strongly dependent on the capture rate our analysis was limited to 93% to avoid unrealistic extrapolation of the energy cost as well as associated CAPEX.

[31] The social discount rate is the discount rate used in economic evaluations of public interventions. There is wide diversity in social discount rates as they can range from 3% to over 10% for developing nations. For climate change policy, it was found that experts favour a lower rate of 2%. See Drupp et al, 2015, Discounting disentangled.
[32] Smith, Robin. Chemical Process Design and Integration, Chapter 2 Process Economics, John Wiley & Sons, Incorporated, 2005.
[33] As explained above, energy prices are dependant on the discount rate used. Values for the central 10% discount rate are reported in the table.

4.2 Introduction to case studies

The techno-economic performance evaluation is performed on the carbon capture unit integration on the small-scale CO_2 emitters. A CO_2 recovery rate of 90% is assumed for the capture unit. The techno-economic comparison is made considering two different solvents (1) conventional solvent (MEA) and (2) advanced solvent (piperazine, PZ). The thermodynamic assumptions for the capture unit are summarised in Table 4.

The following cases were selected for detailed technical and economic assessment of carbon capture integration:

- Natural gas combined cycle
- Natural gas-fired combined heat and power system
- Energy from waste
- Lime kiln

The flue gas composition for each examined case is reported in Table 9

Table 9: Flue gas composition used in this study

Composition (%mol)	CCGT[34]	NG CHP[35]	EfW[36]	Lime kiln[37]
Argon	0.9	0.9	-	-
Water	8.7	8.7	21.0	31.3
Nitrogen	74.3	74.3	61.0	47.3
Oxygen	12.0	12.0	8.0	0.9
Carbon dioxide	4.1	4.1	10.0	20.5

Natural gas combined cycle

Three different cycles are considered, (1) large-scale CCGT full-load (1 GW_{LHV}) with 64% net efficiency, (2) small-scale CCGT full-load (100 MW_{LHV}) with 64% net efficiency, (3) small-scale CCGT part-load (50 MW_{LHV}) with 58% net efficiency. For the part-load operation we considered the same number of operating hours per year as for the full-load case but at reduced electricity production. Thus, the results presented are not time-dependent. It is assumed that working on a part-load basis reduces efficiency by 6%.[38] The natural gas composition is illustrated in Table 10.

[34] NETL, 2019, '*Cost and performance baseline for fossil energy plants. Volume 1: bituminous coal and natural gas to electricity*'.
[35] Ibid.
[36] Magnanelli et al, 2021, 'Scenarios for carbon capture integration in a waste-to-energy plant', *Energy*, 227.
[37] IEAGHG, 2016, 'Techno-Economic Evaluation of Retrofitting CCS in a Market Pulp Mill and an Integrated Pulp and Board Mill', 2016/10.
[38] Yang et al, 2019, 'Design/off-design performance simulation and discussion for the gas turbine combined cycle with inlet air heating', *Energy*, 178, p. 386-99.

Table 10: Natural gas specifications implemented in the simulation[39]

Parameter	Value
Temperature (°C)	15
Pressure (bar$_a$)	1.25
Composition (%mol)	
Methane	89
Ethane	7
Propane	1
Butane	0.1
Pentane	0.01
CO_2	2
N_2	0.89
Lower heating value (MJ/kg)	46.5

It is assumed that the heat requirement for the stripper reboiler, in this case, is provided by taking part of the LP steam from the steam turbine. Consequently, less electricity would be available due to the steam loss entering the steam turbine in case of capture technology.

Natural gas-fired combined heat and power system (NG-fired CHP)

A small-scale (100 MW$_{LHV}$) NG-fired CHP with 25 MW$_{e,}$ and 75 MW$_{th}$ output is considered. A comparison is made between two options for providing the heat requirement for the stripper reboiler; (Option 1) the heat is provided by available heat of the CHP system, and (Option 2) the heat is supplied by the steam used in the steam turbine (as in the case of CCGT). The former option results in lower available heat while the latter produces lower electricity production. Option 1 is a typical case of a CHP plant associated with an industrial site with strict thermal requirements or in the case of a district heating system. In contrast, Option 2 is the case where the CHP maximises electricity production. The amount of heat generated can be used to supplement and compensate for the existing heat requirement of an industrial site, which could reduce the energy requirement from dedicated boilers or other auxiliaries for heating units.

Energy from waste

A small-scale EfW plant is considered with 100 ktCO_2/y emissions, 7.7 MW$_e$ and 8.1 MW$_{th}$ production. This plant's power and heat production is calculated by downscaling the actual data from the EfW plant in Hengelo.[40] The feedstock composition considered in this case is illustrated in Table 11.

[39] Scaccabarozzi et al, 2016, 'Thermodynamic analysis and numerical optimization of the NET Power oxy-combustion cycle', *Applied Energy*, 178, p. 505-26.
[40] IEAGHG, 2020, *CCS on Waste to Energy*, Technical Report 2020-06.

Table 11: Proximate and ultimate analysis of the Municipal solid waste[41]

Parameter	Value
Feedstock (MSW)	
Ultimate analysis (wt%, dry basis)	
Carbon	41.03
Hydrogen	5.86
Nitrogen	0.14
Oxygen	38.22
Sulphur	1.42
Proximate analysis (wt%)	
Water content (wet basis)	6.37
Volatile matter (dry basis)	76.34
Fixed carbon (dry basis)	10.33
Ash (dry basis)	13.33
Lower heating value (MJ/kg)	18.91

In this case, as in the CCGT case, the required heat for the reboiler is supplied by the steam generated by the steam turbine.

Lime kiln

The same as EfW, the small-scale lime kiln system is considered with 100 kt/y CO_2 emissions resulting from 109.2 kt/y lime production.[42] Unlike the other cases, there is no excess heat and electricity production in this case. Therefore, an on-site NG-fired boiler with 90% thermal efficiency is considered to provide the heat required for the reboiler. The NG composition considered for the boiler is the same as in Table 10.

[41] Wang et al, 2022, 'Hydrogen production with an auto-thermal MSW steam gasification and direct melting system: A process modeling', *International Journal of Hydrogen Energy*, 47(10), p. 6508-18.
[42] European Lime Association, 2014, *A Competitive and Efficient Lime Industry*.

Table 12: Performance comparison of considered cases before capture unit integration

	Net Power output (MW)	Available heat (MW)	Electric efficiency (%)	Total efficiency (%)	Fuel flow rate (kg/s)	CO_2 emission (kg/s)	Specific CO_2 emission (kg/MWh)
CCGT (large scale)	1,000	(-)	64	64	33.1	87.6	315.4
CCGT (small-scale)	100	(-)	64	64	3.3	8.7	315.4
CCGT (small-scale)	50	(-)	58	58	1.8	4.8	348.0
NG-fired CHP	25	75	17.5	70	3.0	8.0	288.4
EfW	7.6	8.1	10.7	22	3.8	3.7	848.7
Lime kiln	(-)	(-)	(-)	(-)	(-)	3.7	0.9*

*As there is no heat/power output, the specific CO_2 emission is calculated based on t_{CO2}/t_{lime}

4.3 Results

The techno-economic analysis of 5 cases is reported in the following section. Key results related to the cost of CO_2 capture are summarised in Figure 8. The investment and installation costs of the CO_2 capture plant (CAPEX in Figure 8) range from 37% (1,000 MW CCGT) to >50% (EfW and CHP plants) to almost 60% in the case of part-load 100 MW CCGT. The energy use indicated as electricity losses/purchase (depending on the cases) and heat/fuel requirements account approximately for 24% (Lime kiln) to 37% (CCGT 100 MW) except for large scale CCGT 1,000 MW where the operating costs are 53%. Other O&M costs are consistently between 10-18 $/tCO_2$ except for 1,000 MW CCGT (4 $/tCO_2$) and the part-load 100 MW CCGT (18 $/tCO_2$). The use of an advanced solvent with a lower cost of regeneration decreased the overall cost of CO_2 capture by 3 – 8%, as it affects only the energy cost of each plant. The use of advanced solvent also implies a reduction in the solvent circulation rate and ultimately smaller heat exchangers (regenerator and reboiler). This capital cost difference has not been taken into consideration as this would require a rigorous deign of the CO_2 capture plant. However, the difference in the CAPEX will not be >3-8% (decrease in the heat duty) which is within the range of sensitivity of the CAPEX (-10%/+20%). The techno-economic assessment also reveals a strong negative correlation between the cost of capture and the scale of the emitters, as shown in Figure 9.

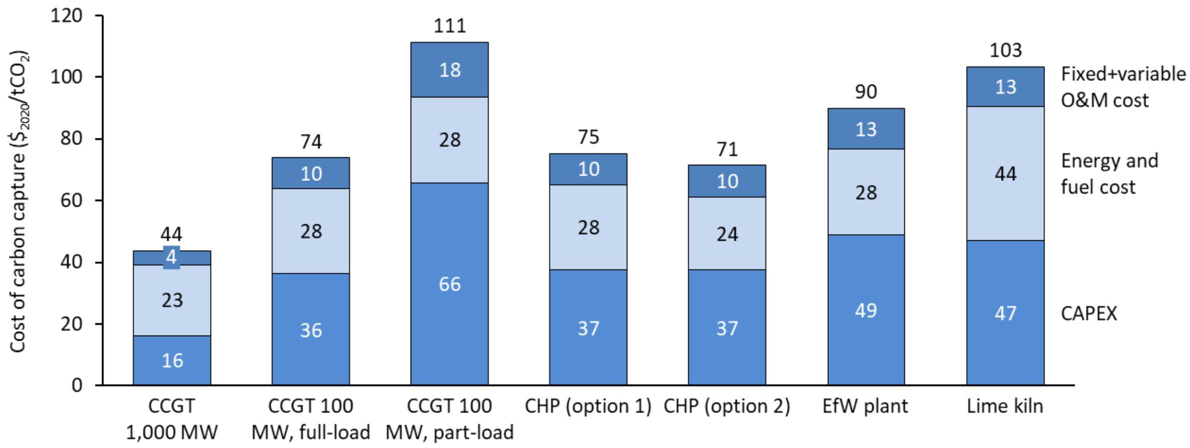


Figure 8: Cost of carbon capture and cost breakdown with conventional and advanced solvents

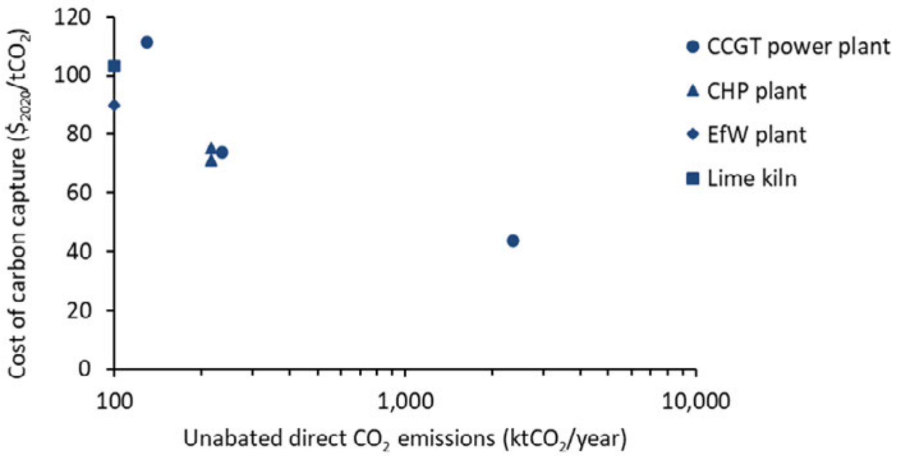


Figure 9: Cost of carbon capture dependence on the scale of emissions

In terms of technical performance, the integration of CO_2 capture technologies will have a different impact on energy and environmental performances. In terms of carbon capture rate, an overall reduction of CO_2 specific emissions of approximately 88% is possible for CCGT and CHP (option 2) while this number slightly decreases to 84% for the EfW and CHP (option 1) and 81% for the lime kiln. The overall primary energy consumption (SPECCA coefficient) changes according to the type of process considered resulting in 2.6 to 3.6 MJ_{LHV}/kg_{CO2} for the CCGT and CHP following heat to 6.5 MJ_{LHV}/kg_{CO2} (lime kiln) and 11.5-13.5 MJ_{LHV}/kg_{CO2} for EfW and CHP following heat which have the lower total energy efficiency (intended as thermal and electric efficiency). The different performance among different cases can be explained in terms of energy efficiency reduction (electric and overall efficiencies). Instead, for the lime kiln case, the installation and operation of an additional boiler (also integrated with the CO_2 capture plant) implies an additional production of CO_2 that is accounted in the overall carbon balance of the plant. These numbers are slightly better in the case of advanced solvents, as shown in Table 13 and detailed in the following sections.

Table 13: Technical performance of the different case studies

Case study	Conventional solvent		Advanced solvent	
	CO_2 specific emissions reduction	SPECCA [MJ_{LHV}/kg_{CO2}]	CO_2 specific emissions reduction	SPECCA [MJ_{LHV}/kg_{CO2}]
CCGT 1,000 MW	88.7%	2.61	88.9%	2.18
CCGT 100 MW (full-load)	88.4%	3.23	88.7%	2.61
CCGT 100 MW (part-load)	88.2%	3.64	88.6%	2.92
CHP (following heat)	88.6%	2.91	88.8%	2.35
CHP (following electricity)	84.6%	11.46	86.2%	7.77
EfW plant	84.1%	13.48	85.5%	10.00
Lime kiln	81.1%	6.48	82.2%	4.78

4.3.1 CCGT integrated with carbon capture

A summary of the thermodynamic performance of the different CCGT cases integrated with carbon capture is given in Table 14 and Table 15. The pump and blower power consumption associated with carbon capture integration are considered in other auxiliary power consumption. Power consumption and heat requirement are calculated based on the correlation presented in Table 4. In the case of conventional amine implementation, carbon capture integration resulted in 7.4%, 8.8%, and 8.8% efficiency reduction for large scale CCGT, small-scale (full-load) and small-scale (part-load), respectively. For the case where the advanced amine is implemented, respective efficiency reductions are 6.3%, 7.3% and 7.3% as a result of the lower energy cost for regeneration. The comparison of SPECCA between full-load and part-load shows an increase by approximately 10% associated with the lower net electric efficiency of the plant (49.2% vs 55.2%).

Table 14: Thermodynamic performance of CCGT integrated with carbon capture with conventional amine

Performance indicators	1,000 MW	100 MW (Full-load)	100 MW (Part-load)
Thermal Input [MW_{LHV}]	1562.5	156.2	86.2
Net power generation [MW_{el}]	885	86.2	42.4
Electrical efficiency [%]	56.6	55.2	49.2
Electricity CO_2 compression [MW_{el}]	24.4	3.0	1.7
Other auxiliaries	11.7	1.7	0.9
Heat demand at the reboiler [MW_{th}]	291.7	33.9	18.7
CO_2 capture rate [%]	90	90	90
CO_2 emissions [kg/MWh]	35.6	36.6	41.1
SPECCA [MJ_{LHV}/kg_{CO2}]	2.6	3.2	3.6

As mentioned before, the heat requirement for the reboiler is provided by the steam generated in the steam turbine. Considering 90% of CO_2 recovery for all cases, less steam is required for advanced amine cases (25.6% less) than the cases with conventional amine; consequently, higher net power output is available. This makes the specific CO_2 emission slightly lower for the case with the advanced amine than in the same case with a conventional solvent.

Table 15: Thermodynamic performance of CCGT integrated with carbon capture with advanced amine

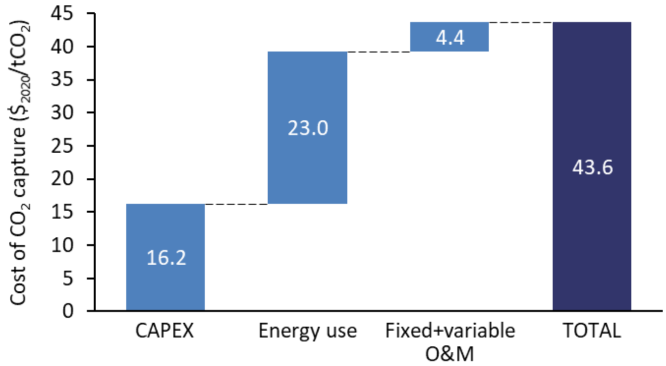
Performance indicators	1,000 MW (Full-Load)	100 MW (Full-load)	100 MW (Part-load)
Thermal Input [MW_{LHV}]	1562.5	156.2	86.2
Net power generation [MW_{el}]	902.1	88.5	43.7
Electrical efficiency [%]	57.7	56.7	50.7
Electricity CO_2 compression [MW_{el}]	24.4	3.0	1.7
Other auxiliaries	11.7	1.7	0.9
Heat demand at the reboiler [MW_{th}]	228.7	25.2	13.9
CO_2 capture rate [%]	90	90	90
CO_2 emissions [kg/MWh]	34.9	35.6	39.8
SPECCA [MJ_{LHV}/kg_{CO2}]	2.2	2.6	2.9

The economic performance of carbon capture integration with different CCGT cases is summarised in Table 16. It is worth mentioning that the CCGT is evaluated in two distinct cases, working either on a full-load or a part-load basis. Therefore, although working on a part-load basis has a significant impact on the thermodynamic performance (as illustrated in the above tables), its effect on the electricity cost is linked to the fact that the cost of capital investment – the same as in the case of full-load – is amortised over a smaller electricity output. The total annualised cost is 92.2 M$/y for the 1,000 MW (full-load) case and 12.9 M$/y for 100 MW (part-load). This results in a stronger increase in product cost for the smaller plant size.

Table 16: Economic performance indicators of CCGT integrated with carbon capture (conventional amine)

Performance indicators	1,000 MW (Full-Load)	100 MW (Full-load)	100 MW (Part-load)
TCR [M$]	310.8	69.6	69.6
Annualised TCR [M$/y]	34.2	7.7	7.7
Electricity cost [M$/y]	48.6	5.8	3.2
Operating and maintenance cost (Fixed & variable)	9.3	2.1	2.1
Total annualised cost [M$/y]	92.2	15.6	12.9
∆ cost of product [$/MWh]	14.0	24.3	41.1
Cost of CO_2 capture [$/$t_{CO2}$]	43.6	73.8	111.3
Cost of CO_2 avoided [$/$t_{CO2}$]	50.0	87.2	134.0

The cost of the CO_2 capture breakdown is presented in Figure 10 and Figure 11. The generated steam for the steam turbine is partially used for the reboiler heat requirement compensation. Moreover, the compression and auxiliary power requirement are provided by the available electricity. Therefore, less revenue from selling the electricity is available than in the case without carbon capture integration which is presented as electricity cost in Table 16 and in the below figures. The costs of CO_2 capture for the CCGT (1,000 MW and 100 MW) are 43.6 $/$t_{CO2}$ and 73.8 $/$t_{CO2}$, respectively. The TCR of 1,000 MW CCGT is higher than 100 MW CCGT ($310.8 M and $69.6 M, respectively); however, its specific CAPEX is lower than small scale CCGT due to its higher capture rate (2.1 Mt_{CO2}/y and 0.2 Mt_{CO2}/y, respectively) thus decreasing the cost of CO_2 capture by 20 $/$t_{CO2}$. The advanced amine implementation decreases only the operating costs (electricity) from 23 $/$t_{CO2}$ to 19.6 $/$t_{CO2}$ for 1,000 MW, and 27.7 $/$t_{CO2}$ to 23 $/$t_{CO2}$ for 100 MW.



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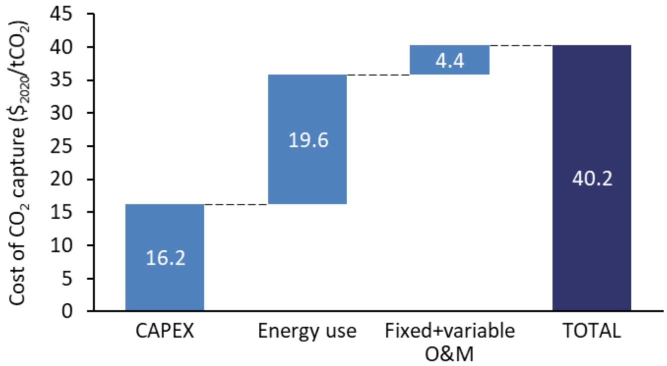
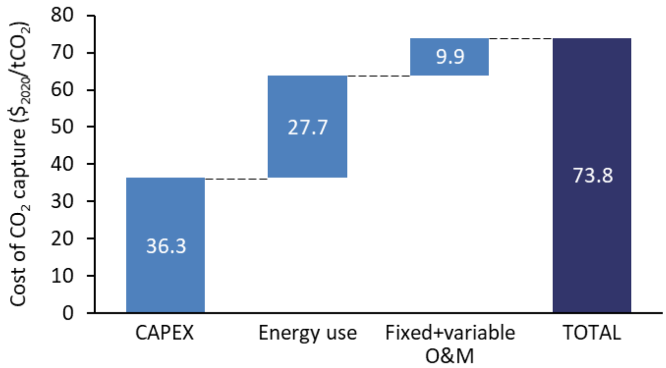


b)

Figure 10: The breakdown of CO_2 capture cost for 1,000 MW CCGT integrated with carbon capture. a) with conventional solvent b) with advanced solvent.



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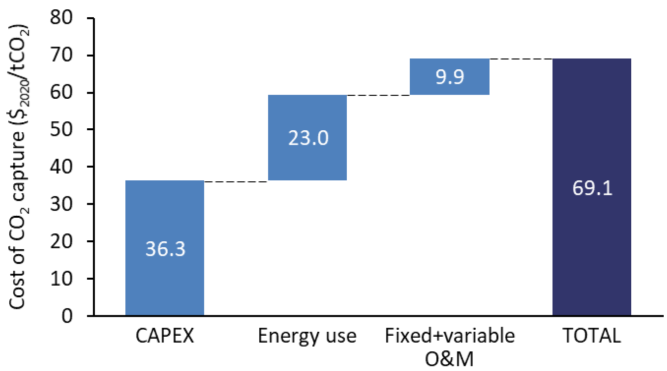


b)

Figure 11: The breakdown of CO_2 capture cost for 100 MW CCGT integrated with carbon capture. a) with conventional solvent b) with advanced solvent

The sensitivities of the discount rate, the specific purchase cost of the capture plant and the energy price on the cost of CO_2 avoided for 1,000 MW CCGT are assessed, Figure 12. Table 7 shows that differences in the discount rate (from 3.5% to 12%) change the electricity cost from \$59.5/MWh to \$56.1/MWh. It is illustrated that with discount rate increment, the CCA increases from 42.9 \$/t_{CO2} to 52.6 \$/t_{CO2} for the conventional solvent implementation. While for the case with advanced solvent, the CCA ranges between 38.0-47.7 \$/t_{CO2}. It is worth mentioning that, although the discount rate increment slightly reduces the electricity cost (Table 7), it increases the annual capital cost. The higher impact of the CAPEX than electricity price (1.57 times as shown in Figure 11) results in an overall increase in the CCA. On the other hand, the CCA steadily increases from 48.3 \$/t_{CO2} to 54.7 \$/t_{CO2} (conventional solvent) with the increase in specific cost of capture plant from 90 \$/(t/y) to 120 \$/(t/y). The same trend occurred with the advanced amine as the CCA increased from 43.5 \$/t_{CO2} to 49.7 \$/t_{CO2} for the same changes in the specific capture plant cost. In terms of energy price, a drastic change of ±50% of the mid cost could decrease/increase the cost of CO_2 avoidance ±24.4-26.4% for advanced and conventional solvents which is contained despite the huge variation in view of the overall impact of the electricity cost in the overall CCC and CCA.

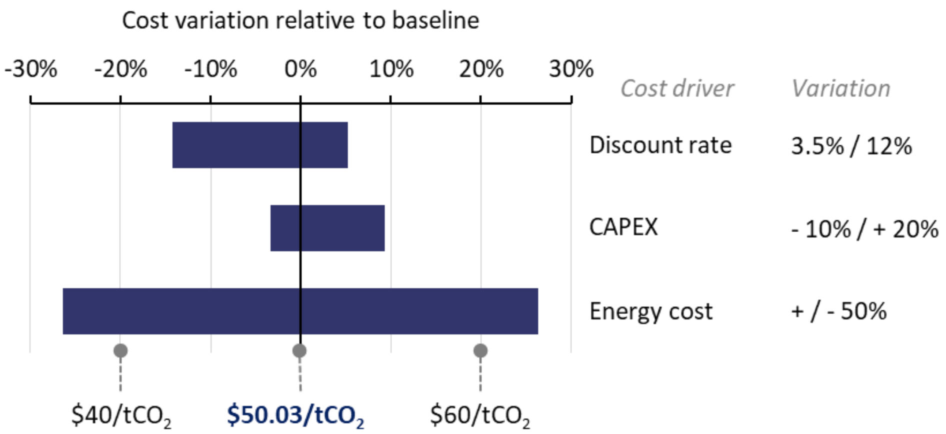


Figure 12: Sensitivity analysis for the cost of CO_2 avoidance for a 1,000 MW CCGT with conventional solvent

What stands out from the sensitivity on 100 MW CCGT (full-load) is the growth of CCA from 84.7 \$/t_{CO2} to 94.9 \$/t_{CO2} for conventional amine, or from 77.3 \$/t_{CO2} to 86.7 \$/t_{CO2} for advanced amine, with the increase of capture rate (87% to 93%) as in Figure 13. Other sensitivities on the 100 MW CCGT (discount rate, specific capture plant cost, and energy price) follow a similar pattern as the 1,000 MW and are depicted in Figure 13. However, the CCA is less sensitive to the energy cost, and more sensitive to parameters that impact the levelised capital cost, as the discount rate and the CAPEX. This is because at lower plant capacity the CAPEX impact increases from 37.8% to 49.2% of the total CCC. For a conventional solvent, under a 3.5% discount rate the CCA drops 20.3%, and it increases 7.3% when a 12% discount rate is used. For advanced solvents the sensitivity is stronger: the CCA decreases 22.0% and increases 7.8% respectively. A change in the CAPEX has a direct correlation with the CCA, as a change from -10% to +20% in CAPEX varies the CCA -4.5% and 12.4% with respect to the central cost for a conventional amine, and -4.8% and 13.2% for an advanced amine. In terms of ±50% of the mid energy, the price changes the cost of CO_2 avoidance by ±18.7%-16.6% for conventional and advanced solvents, respectively.

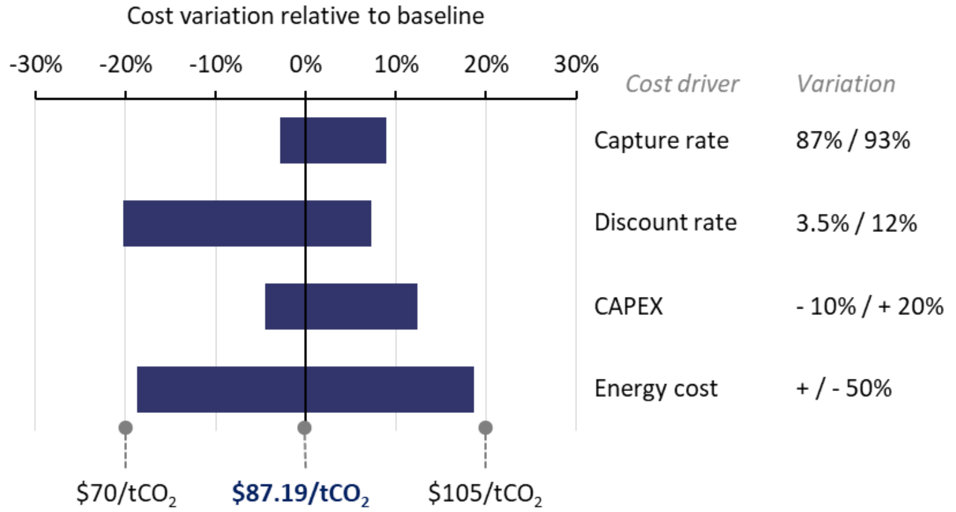


Figure 13: Sensitivity analysis for the cost of CO_2 avoidance for a 100 MW CCGT with conventional solvent

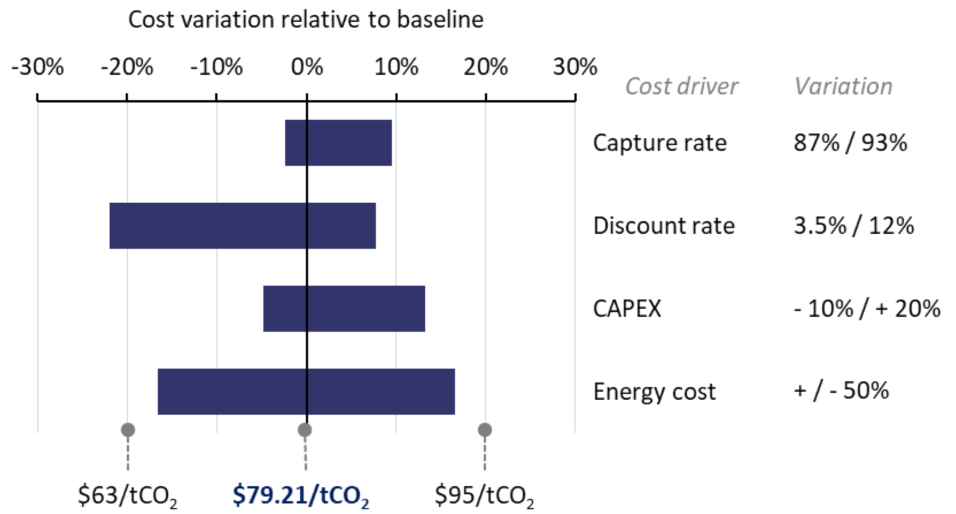


Figure 14: Sensitivity analysis for the cost of CO_2 avoidance for a 100 MW CCGT with advanced solvent

4.3.2 Natural gas-fired CHP integrated with carbon capture

Capture unit implementation in Option 1 (LP steam for reboiler provided by the steam turbine) drops the overall efficiency by 8.8% and 7.4% for the conventional and advanced cases, respectively. While for Option 2 (LP steam for reboiler provided by using part of the heat generated), the capture unit implementation results in a drop in the overall efficiency of 24.7% and 19.2% for conventional and advanced cases, respectively. It is worth mentioning that the specific emission in these cases is calculated based on the total energy (electrical + thermal) available. The drops in the energy efficiency is the reason of a much higher SPECCA and E_{CO2} higher for the case in Option 2.

Table 17: Thermodynamic performance of NG-fired CHP integrated with carbon capture with conventional and advanced amine

Performance indicators	Option 1 (Conventional)	Option 1 (Advanced)	Option 2 (Conventional)	Option 2 (Advanced)
Thermal Input [MW_{LHV}]	142.8	142.8	142.8	142.8
Net power generation [MW_{el}]	12.4	14.5	20.7	20.7
Available heat [MW_{th}]	75	75	44	51.9
Electrical efficiency [%]	8.7	10.2	14.5	14.5
Total efficiency [%]	61.2	62.6	45.3	50.8
Electricity CO_2 compression [MW_{el}]	2.7	2.7	2.7	2.7
Other auxiliaries	1.5	1.5	1.5	1.5
Heat demand at the reboiler [MW_{th}]	31.0	23.1	31	23
CO_2 capture rate [%]	90	90	90	90
CO_2 emissions [kg/MWh_{total}]	33.0	32.2	44.5	39.7
SPECCA [MJ_{LHV}/kg_{CO2}]	2.9	2.3	11.5	7.8

The economic performance of carbon capture integration with different NG-fired CHP cases is summarised in Table 18. Implementation of advanced solvent for Option 1 lowers the drops in the revenue from selling the electricity (5.3 to 4.4 M$/y), while for Option 2 it lowers the drops in the revenue from selling the heat (2.8 to 2.1 M$/y). In this case, the higher cost of CO_2 capture for option 1 is depending on prices assumption (heat and electricity) and how they affect the TAC according to the consumption required from the reboiler. In a different scenario with lower cost of electricity, the cost of CO_2 capture could change considerably as highlighted in the sensitivity analysis.

Table 18: Economic performance indicators of NG-fired CHP integrated with carbon capture

Performance indicators	Option 1 (Conventional)	Option 1 (Advanced)	Option 2 (Conventional)	Option 2 (Advanced)
TCR [M$]	65.6	65.6	65.6	65.6
Annualised TCR [M$/y]	7.2	7.2	7.2	7.2
Electricity cost [M$/y]	5.3	4.4	1.8	1.8
Heat cost [M$/y]	-	-	2.8	2.1
Operating and maintenance cost (Fixed & variable)	1.9	1.9	1.9	1.9
Total annualised cost [M$/y]	14.5	13.6	13.8	13.1
Cost of CO_2 capture [$/t$_{CO2}$]	75.3	70.6	71.4	67.7

The cost of the CO_2 capture breakdown for option 1 is presented in Figure 15. CAPEX is the main contributor to the cost of CO_2 capture (49.7% and 53.0% for conventional and advanced amine, respectively). These cases present a similar CO_2 capture cost associated to CAPEX (36 $/t$_{CO2}$) as the small-scale CCGT, which is directly related to the amount of CO_2 captured every year (190-215 kt/y) and the comparable capture rate. As a consequence also the final cost of CO_2 capture is comparable as the cost of energy required to operate the reboiler and the other auxiliary consumptions are based on the same assumptions and specific costs.

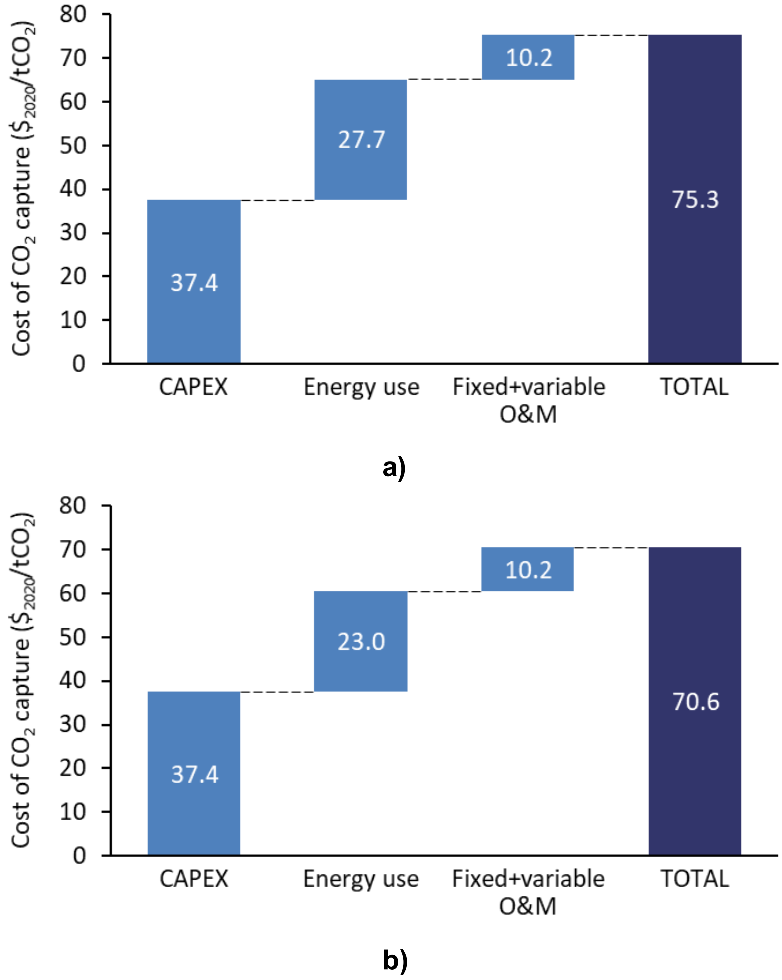


Figure 15: The breakdown of CO_2 capture cost for NG-fired CHP (option 1) integrated with carbon capture. a) with conventional solvent b) with advanced solvent

The sensitivities of capture rate, discount rate, the specific purchase cost of capture plant and energy price on the cost of CO_2 capture for NG-fired CHP (option 1 and option 2) are assessed and are shown in Figure 16 to Figure 19. The changes in capture rate from 87% to 93%, increases the CCC for both conventional and advance amine (74.0 $\$/t_{CO2}$ to 79.0 $\$/t_{CO2}$ and 69.9 to 74.5, respectively) for option 1. While for option 2, it increases the CCC with conventional amine by 4.1 $\$/t_{CO2}$ and by 3.8 $\$/t_{CO2}$ for advanced amine. Difference in discount rate (from 3.5% to 12%) changes the CCC from 59.8 $\$/t_{CO2}$ to 80.8 $\$/t_{CO2}$ (option 1) for the conventional solvent implementation. While for the case with advanced solvent, the CCC ranges between 54.8-76.2 $\$/t_{CO2}$. The same trend is expected for the discount rate effect on CCC for option 2. In addition, as the CAPEX accounts for approximately 53% of the cost of capture, a change in the CAPEX specific cost by -10%/+20% changes the cost of CO_2 capture from -5% to +13%. When considering changes in energy costs (±50%), option 1 shows a change of the cost of CO_2 capture of ±18.4% for conventional solvents and ±16.2% for advanced solvents, while option 2 shows a change of the cost of CO_2 capture ±16.6/±14.8% for conventional and advanced solvents, respectively. These results are impacted by the high contribution of energy costs on the total annualised cost (32.6%) as reported in Figure 15.

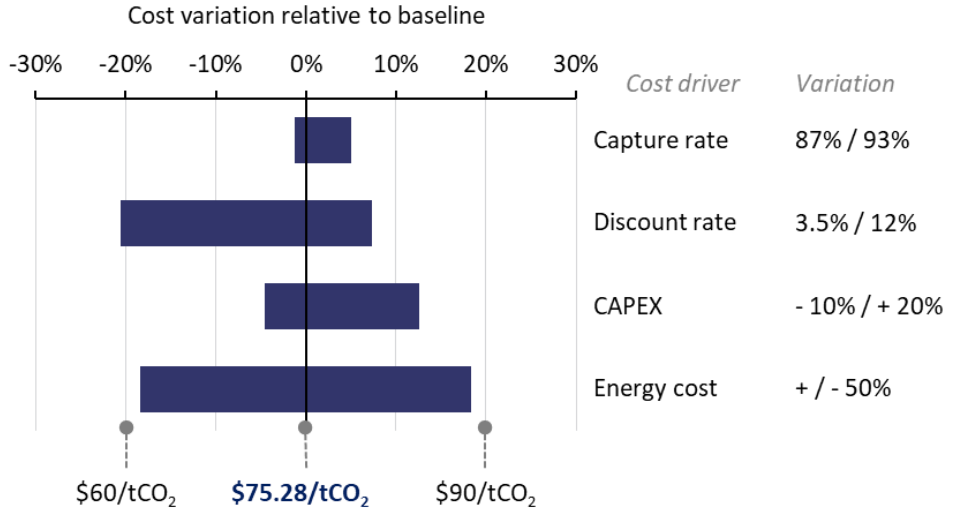


Figure 16: Sensitivity analysis for the cost of CO_2 capture for a natural gas-fired CHP (option 1) with conventional solvent

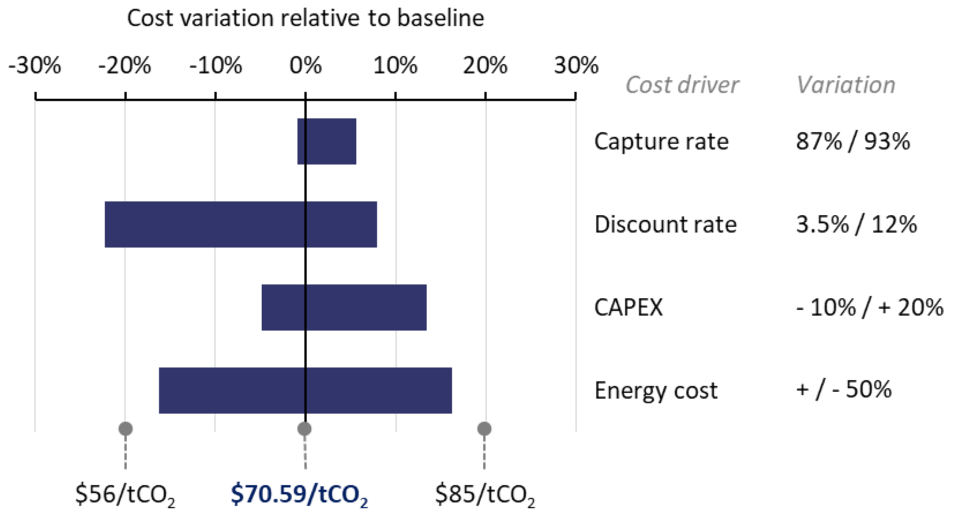


Figure 17: Sensitivity analysis for the cost of CO_2 capture for a natural gas-fired CHP (option 1) with advanced solvent

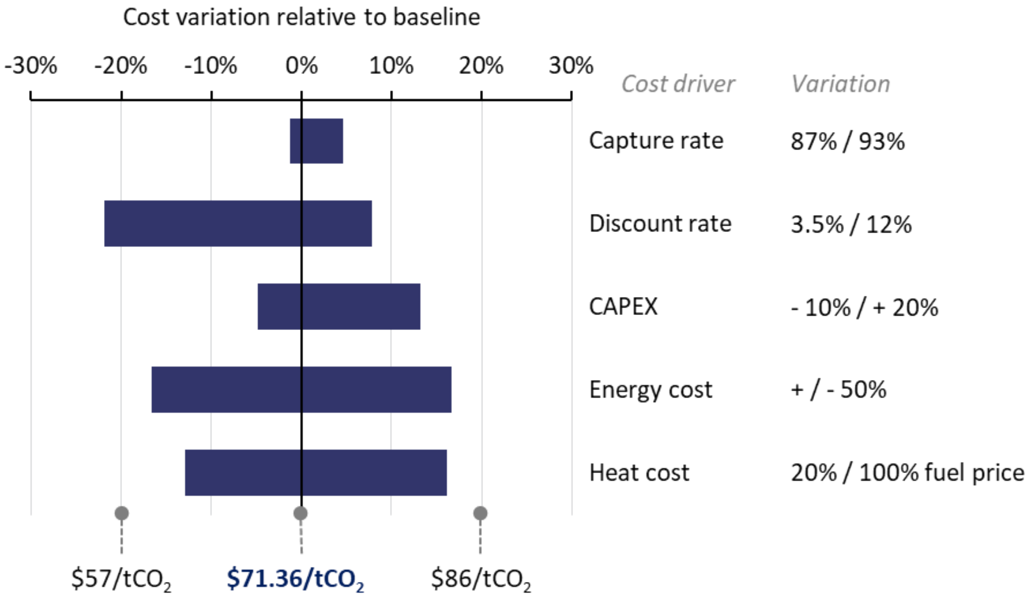


Figure 18: Sensitivity analysis for the cost of CO_2 capture for a natural gas-fired CHP (option 2) with conventional solvent

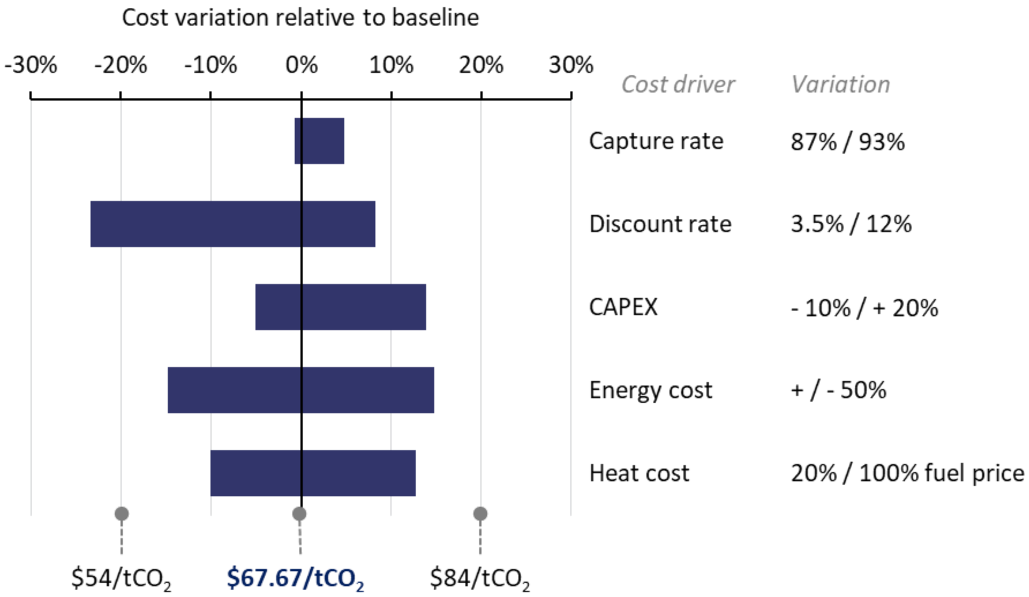


Figure 19: Sensitivity analysis for the cost of CO_2 capture for a natural gas-fired CHP (option 2) with advanced solvent

Unlike option 1, in option 2 the required heat for the reboiler is compensated by the available heat within the system. Therefore, heat price significantly impacts the CCC, since it reduces the revenues by selling heat to other users. Figure 18 and Figure 19 show that the sensitivity to the heat cost is higher for conventional amines, as the heat requirement for the conventional amine is 31 MW while for the advanced amine it is 23 MW. However, this 8 MW difference in heat requirement has less impact on the CCC at a low heat price. Therefore, conventional amine implementation at low heat costs ($1.2/GJ). is competitive to advanced amine, with a CCC of 62.1 and 60.8 $/t_{CO2}$ respectively. However, the advantages of advanced amine are much evident at high heat prices (e.g. 6 $/GJ) as the difference in the CCC becomes more pronounced: 76.2 $/t_{CO2}$ vs 82.9 $/t_{CO2}$.

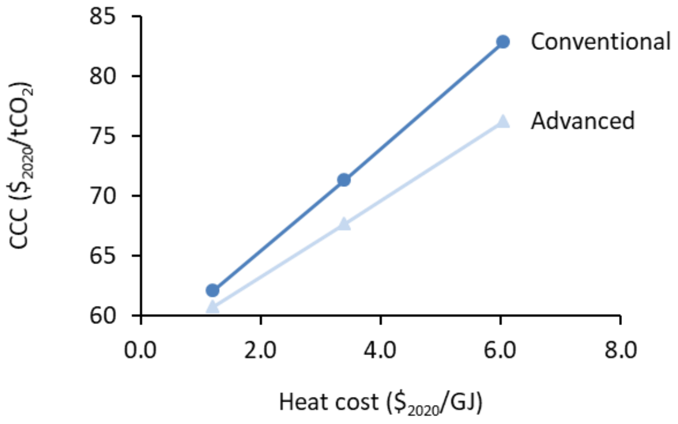


Figure 20: Effect of heat price on the cost of CO_2 capture for NG-fired CHP (option 2)

4.3.3 Energy from waste integrated with carbon capture

Capture unit implementation in a small-scale EfW plant results in a drop in the total efficiency of 8.1% for conventional and 6.7% for the advanced case. Performance losses are dictated mainly by heat requirements for the reboiler, which is compensated by the steam generated for the steam turbine. The specific CO_2 emission for the case with the conventional amine capture is 135.1 kg_{CO2}/MWh and the primary energy demand of 13.5 MJ/$kg_{CO2,captured}$. While for the case with advanced solvent, the respective specific CO_2 emission and the primary energy demand are 122.7 kg_{CO2}/MWh 10 MJ/$kg_{CO2,captured}$. Those numbers are significantly worse than the previous cases due to the significantly lower performance of the EfW plant (as reported in Table 12).

Table 19: Thermodynamic performance of EfW integrated with carbon capture with conventional and advanced amine

Performance indicators	Conventional	Advanced
Thermal Input [$MW_{LHV,\ SRF}$]	71.4	71.4
Net power generation [MW_{el}]	1.8	2.8
Heat production [MW_{th}]	8.1	8.1
Total efficiency [%]	13.9	15.3
Electricity CO_2 compression [MW_{el}]	1.3	1.3
Other auxiliaries	0.7	0.7
Heat demand at the reboiler [MW_{th})	14.4	10.7
CO_2 capture rate [%]	90%	90%
CO_2 emissions [kg/MWh_{total}]	135.1	122.7
SPECCA [MJ_{LHV}/kg_{CO2}]	13.5	10.0

The economic performance of carbon capture integration is summarised in Table 20. The difference in the total annualised cost comes from the difference in electricity cost. As the advanced solvent results in lower heat requirement for the reboiler, less generated steam is required for the compensation, resulting in less cost associated with the electricity loss. In this case, the price of feedstock that is required to charge for the EfW company in order to cover the cost for disposal ranges from 75.7-79.9 $/tonne$_{waste}$. This results in an increase of 43.4-45.9% of the existing price of 174.1 $/tonne$_{waste}$.[43]

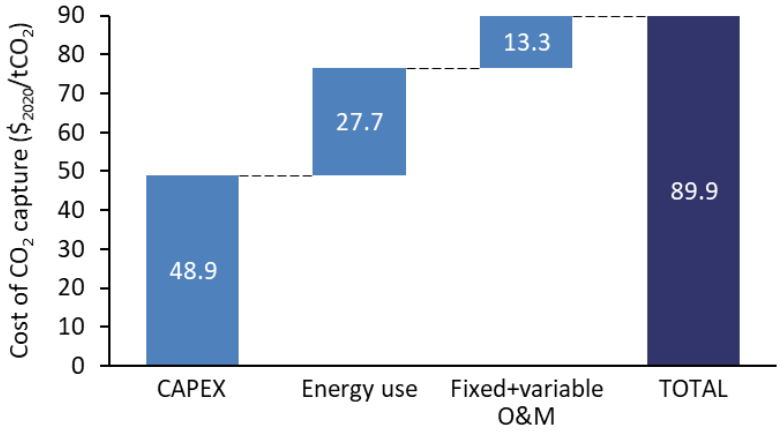
Table 20: C EfW integrated with carbon capture

Performance indicators	Conventional	Advanced
TCR [M$]	39.9	39.9
Annualised TCR [M$/y]	4.1	4.1
Electricity cost [M$/y]	2.5	2.1
Operating and maintenance cost (Fixed & variable)	1.2	1.2
Total annualised cost [M$/y]	7.8	7.4
∆ price of feedstock [$/t$_{waste}$]	77.4	73.2
Cost of CO_2 capture [$/t$_{CO2}$]	87.0	82.4
Cost of CO_2 avoided [$/t$_{CO2}$]	87.0	82.4

The cost of the CO_2 capture breakdown is presented in Figure 21. CAPEX is the main contributor to the cost of CO_2 capture (54.4% and 57.4% for conventional and advanced, respectively). Compared to previous cases, a reduced CO_2 avoidance (84.4%) is achieved as by the final CO_2 emissions (135 kg$_{CO2}$/MWh) compared 88% of CCGT 100 MW size with 35-40 kg$_{CO2}$/MWh. The benchmark technology without CO_2 capture presents a CO_2 specific emission of 848 kg$_{CO2}$/MWh (≈2.7 times higher than CCGT) and the resulting CAPEX of this plant is significantly higher than previous cases (49.7 $/t$_{CO2}$ compared to 36.7 $/t$_{CO2}$). Another important element that impacts the final CAPEX is the size of the plant, in this case 100 kt$_{CO2}$/y, therefore less than 50% smaller than previous cases (CCGT 100 MW and NG-fired CHP).

It should be noted that the cost of CO_2 capture and that of CO_2 avoidance are the same for the EfW case. This is a result of the methodology used in this study for EfW, which relates the emission reduction to the waste feedstock and not to the electricity or heat produced by the EfW facility.[44]

[43] Warringa G., 2021, *Waste Incineration under the EU ETS: An assessment of climate benefits*.
[44] The cost of CO_2 avoidance would be higher than that of CO_2 capture if electricity and/or heat from the EfW were taken as the relevant outputs. This is because of the energy requirements from the capture plant, which would reduce the amount of energy available for export (as well as reducing the CO_2 emitted).



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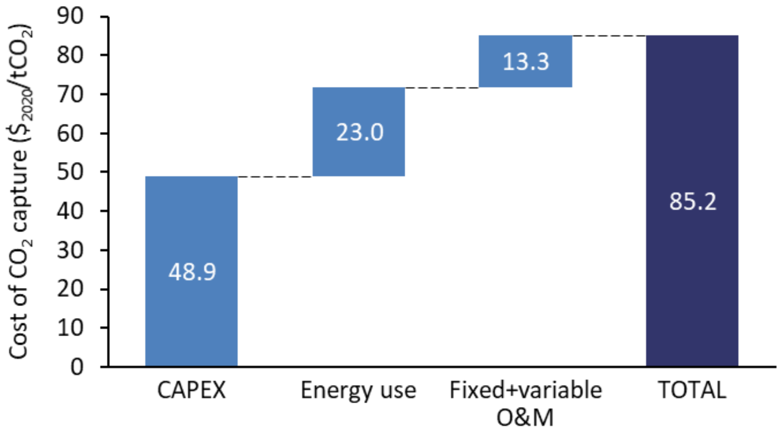


b)

Figure 21: The breakdown of CO_2 capture cost for EfW integrated with carbon capture. a) with conventional solvent b) with advanced solvent

The sensitivities of capture rate, discount rate, specific purchase cost of capture plant and energy price on the cost of CO_2 avoided for EfW are assessed. At capture rate of 87%, the CCA is 89.4 $\$/t_{CO2}$ (conventional amine), and it steadily increases to 93.2 $\$/t_{CO2}$ at the capture rate of 93% while for the advanced amine, the CCA increases from 64.3 $\$/t_{CO2}$ to 92.6 $\$/t_{CO2}$. The increase in the CCC at higher capture rate results from the specific energy requirement of the solvent regeneration that increases up to 2.1 MJ/kg_{CO2} (conventional), moving from 87% to 93% capture rate. While it decreased slightly to 2 MJ/kg_{CO2}.[45] In the same way, the CCA increases while the discount rate increases. As the CCA are 69.2 $\$/t_{CO2}$, 89.8 $\$/t_{CO2}$ and 97.2 $\$/t_{CO2}$ (conventional amine) and 64.3 $\$/t_{CO2}$, 85.2 $\$/t_{CO2}$ and 92.6 $\$/t_{CO2}$ (advanced amine) for the respective discount rate of 3.5%, 10% and 12%. A change in the CAPEX has a direct correlation with CCA. As a change from -10% to +20% in CAPEX varies the CCA from 85.4 $\$/t_{CO2}$ to 102.2 $\$/t_{CO2}$ (conventional amine) and from 80.7 $\$/t_{CO2}$ to 97.5 $\$/t_{CO2}$ (advanced amine). A ±50% change in the mid energy price results in a change in the cost of CO_2 capture by ±15.4-13.5% for conventional and advanced solvents, respectively.

[45] Sánchez Fernández et al, 2014, 'Thermodynamic assessment of amine based CO_2 capture technologies in power plants based on European Benchmarking Task Force methodology', *Fuel*, 129, 318-329.

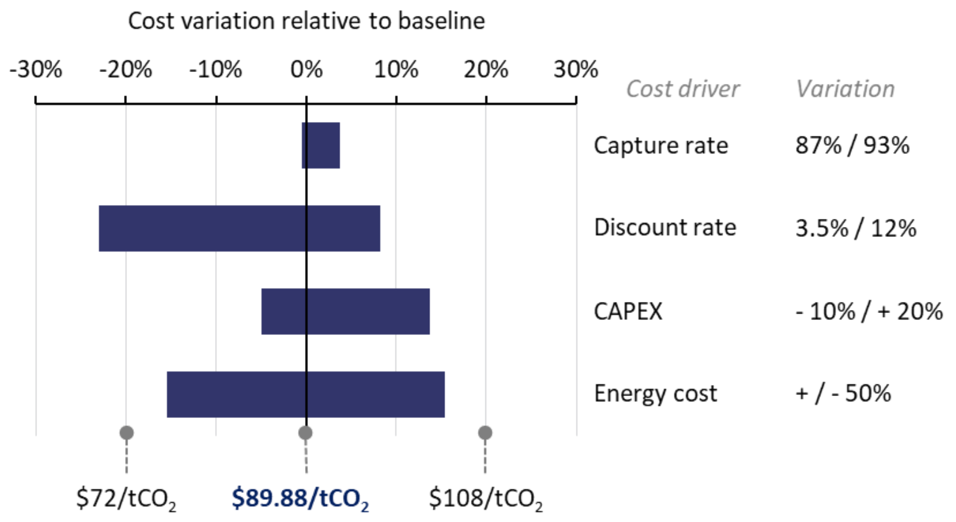


Figure 22: Sensitivity analysis for the cost of CO_2 capture for an EfW plant with conventional solvent

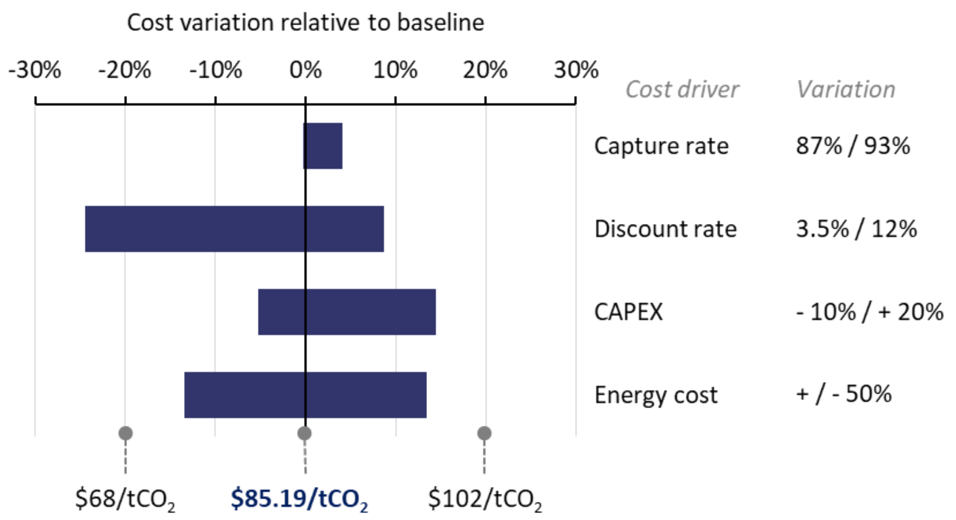


Figure 23: Sensitivity analysis for the cost of CO_2 capture for an EfW plant with advanced solvent

4.3.4 Lime kiln integrated with carbon capture

The excess CO_2 flowrate illustrated in Table 21 represents the extra CO_2 stream resulting from an additional NG boiler that will produce heat for the reboiler of the CO_2 capture plant. As advanced solvent application results in lower heat requirement for the reboiler, less NG is required than the case with conventional solvent. Auxiliary and CO_2 compression power requirements are assumed from the state-of-the-art CCGT with an efficiency of 64% (excess CO_2 emission from the CCGT is not considered in this case). The process is considered with no heat available for the partial or total steam production required for the stripper.

The cost of the reboiler is taken from data available in literature[32]. The reference cost (C_0) is 0.328 M$ for 20,000 kg/h of steam (Q_0), a scale factor of 0.81 and installation cost ×3 the purchase cost. The amount of steam required directly linked with the heat required at the stripper therefore a different boiler size and associated cost is calculated depending on the type of process (conventional vs advanced).

Table 21: Thermodynamic performance of lime kiln integrated with carbon capture with conventional and advanced amine

Performance indicators	Conventional	Advanced
Direct CO_2 flow to capture plant* [kt/y]	123.9	116.7
Indirect CO_2 flow [kt/y] **		
Electricity CO_2 compression [MW_{el}]	1.58	1.49
Other auxiliaries	0.79	0.74
Heat demand at the reboiler [MW_{th}]	14.3	10
CO_2 capture rate [%]	90%	90%
CO_2 emissions [$kg/kg/_{lime}$]	0.17	0.16
SPECCA [MJ_{LHV}/kg_{CO2}]	6.48	4.78

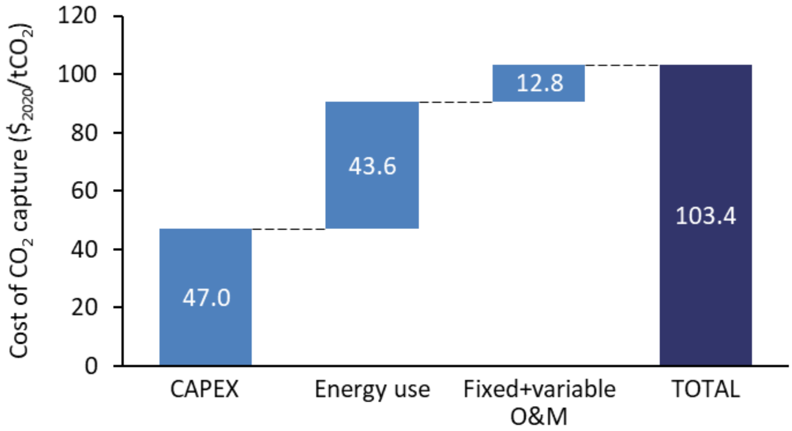
* Includes the extra CO_2 due to the excess NG requirement for this case.
** CO_2 emission associated with electricity purchased from the grid.

The economic performance of carbon capture integration with the lime kiln case is summarised in Table 22. The difference in TCR between the conventional and advanced cases is due to the difference in capital cost of the extra boiler needed in this case to generate a different amount of heat for regeneration. Less heat is required in the case of advanced amine implementation; therefore, a smaller and, consequently, cheaper boiler is necessary for this case. Lime kiln is the only case assessed in this report in which excess fuel is needed, and its associated cost is shown below.

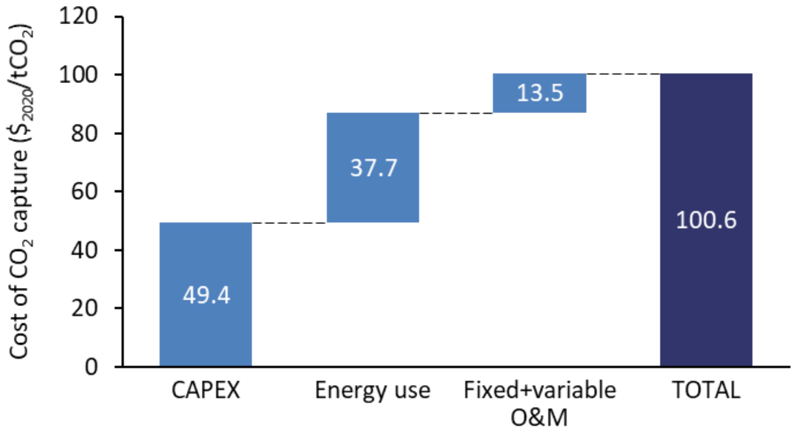
Table 22: Economic performance indicators of lime kiln integrated with carbon capture

Performance indicators	Conventional	Advanced
TCR [M$]	47.5	47.1
Annualised TCR [M$/y]	5.2	5.1
Electricity cost [M$/y]	2.3	2.2
Fuel cost [M$/y]	2.6	1.8
Operating and maintenance cost (Fixed & variable)	1.4	1.4
Total annualised cost [M$/y]	11.5	10.6
Δ cost of product [$/MWh]	105.5	96.8
Cost of CO_2 capture [$/$t_{CO2}$]	103.3	100.6
Cost of CO_2 avoided [$/$t_{CO2}$]	142.1	128.6

The cost of the CO_2 capture breakdown is presented in Figure 24. CAPEX is the main contributor to the cost of CO_2 capture (45.4% and 49.1% for conventional and advanced, respectively).



a)



b)

Figure 24: The breakdown of CO_2 capture cost for lime kiln integrated with carbon capture. a) with conventional solvent b) with advanced solvent

The sensitivities for the lime kiln are assessed, Figure 25 and Figure 26. In this case, unlike other previous cases, no heat and electricity are available within the system. Therefore, additional fuel is necessary to compensate for the required heat for the reboiler and electricity is purchased from the grid. Hence, the difference in discount rate changes the fuel and electricity (for industrial usage) price, as in Table 7. The changes in capture rate from 87% to 93%, results in a sharp rise in CCA for both conventional and advance amine (from 133.0 $\$/t_{CO2}$ to 165.3 $\$/t_{CO2}$ and from 121.6 $\$/t_{CO2}$ to 149.0 $\$/t_{CO2}$, respectively). This is due to the high contribution of CAPEX to the cost of CO_2 capture (45.4% and 49.1% for the conventional and advanced amine, respectively), Figure 24.

As for the EfW case, the CAPEX accounts for a higher cost than in the CHP and small CCGT cases (47-49 $\$/t_{CO2}$ compared to 36-37 $\$/t_{CO2}$). This is explained by the fact that both EfW and lime kiln plants present a high carbon intensity and smaller plants (capturing approximately 90 kt_{CO2}/y).

It should also be highlighted that both EfW and lime plants present flue gases with more highly concentrated CO_2 (approximately 30% mol fraction on a dry basis for the lime kiln). Therefore, there is the potential for greater cost reductions from the application of some of innovative CO_2 capture technologies such as membrane and MCFC, which are particularly cost-competitive in presence of high CO_2 content as discussed in Chapter 3.

Difference in discount rate (from 3.5% to 12%) changes the CCA from 115.3 $\$/t_{CO2}$ to 151.7 $\$/t_{CO2}$ (-19% to +7%) for the conventional amine, and from 101.9 $\$/t_{CO2}$ to 138.1 $\$/t_{CO2}$ (-21% to +7%) for advanced amine. Regarding the sensitivity to the energy price, ±50% of the mid energy price shows a change in the cost of CO_2 capture ±21.1-18.7% for conventional and advanced solvents, respectively.

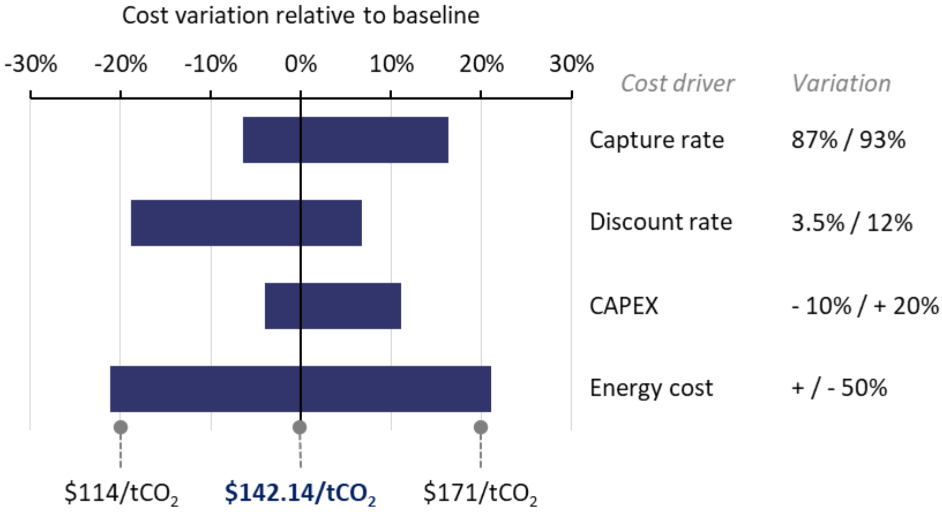


Figure 25: Sensitivity analysis for the cost of CO_2 avoidance for a lime kiln plant with conventional solvent

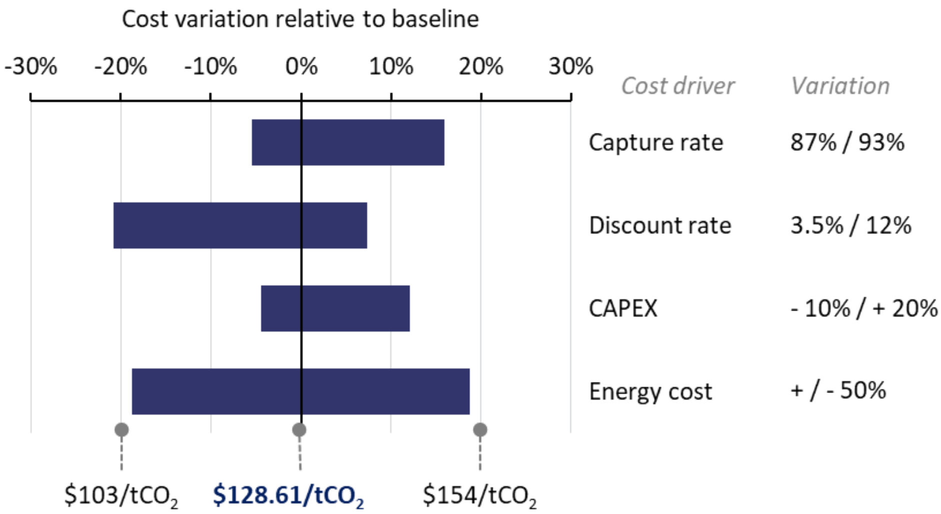


Figure 26: Sensitivity analysis for the cost of CO_2 avoidance for a lime kiln plant with advanced solvent

5 Policy assessment

5.1 Policy modelling

The impact of current and proposed policies and incentives to make an economically viable case for small-scale carbon capture is modelled by building a cash flow over the lifetime of the investment. This is done for the small-scale CCGT and its 1 GW_e net-power-output analogue, and the lime kiln. The analysis covers four geographic regions with distinct policy support and energy prices. The regions focus of this analysis are the Netherlands, California and Texas in the United States, and China. The assessment is centred around the net present value (NPV) of the investments. The discounted payback period and the impact on product prices is also covered. The incentives that have been considered, the underlying assumptions, and a description of how each incentive was modelled are offered in the following Sections.

5.1.1 Policies considered

For each region, the analysis presented in this section considers:

- **Policies and incentives** that have already been implemented.
- An assessment of the **level of support required to allow investments to break even**.

Only incentives providing directly monetizable support have been included. This includes **carbon pricing, capital or construction phase support, revenue support, and tax credits.** Applicable policies and incentives for the regions of interest are summarised in Table 23. Notwithstanding, it should be acknowledged that policies and regulations that do not provide economic support but that create an enabling environment for carbon capture can be as important to attract investment. Conversely, investors are likely to apply more stringent criteria than are considered in the presented analysis when evaluating business cases. Also, a key caveat is that smaller but private companies might be better able to finance projects without an evident high NPV compared to public companies. A broader assessment of potential future policy frameworks and of business cases for carbon capture is beyond the scope of this study.

Table 23: Current incentives implemented in each region

Incentives	Netherlands	California	Texas	China
Carbon pricing	EU ETS and Dutch carbon tax	Cap-and-Trade program	-	National ETS
Capital support	-	-	-	Can be available[46]
Revenue support	SDE++	-	-	-
Tax credit	-	Tax credit 45Q	Tax credit 45Q	-

Carbon pricing

Carbon pricing is an instrument that internalises the costs of GHG emissions, shifting the burden to the emitters through a price. It is an economic signal that provides an incentive to abate emissions to avoid costs, expressed as a value per tonne of carbon dioxide equivalent. Its two basic forms are:

- **An emissions trading scheme (ETS), also known as cap and trade**, where a central authority sets a maximum level of emissions – a cap – and allowances are allocated among

[46] We assume a match-funded approach, with capital grants covering 50% of the capital costs.

emitters. These can then be traded at a market price between different emitters. The price, determined by the market, remains flexible but it provides certainty about the level of emissions;

- **A carbon tax** that sets an explicit price on carbon. Whilst the carbon price is pre-defined, the quantity of emissions reduction is determined by the market.

The long-term projections of the carbon prices for all the regions focus of this study are depicted in Figure 27.

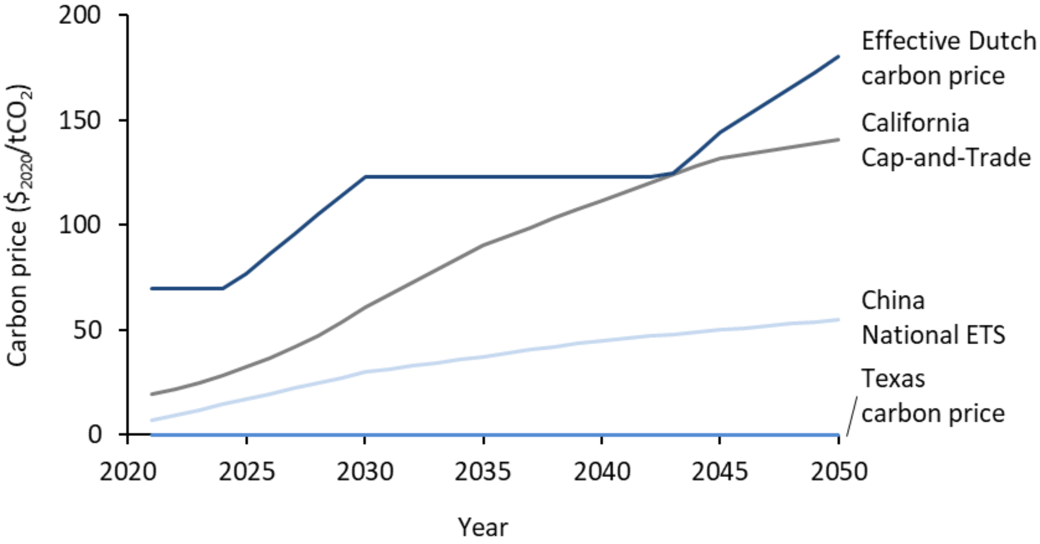


Figure 27: Carbon price projections for different regions used for the policy analysis

The Netherlands

The regions focus of this study have adopted different approaches to carbon pricing. In the Netherlands, tradeable allowances under the European Emissions Trading Scheme (EU ETS) are complemented by the Dutch Carbon Tax, introduced on January 2021. The EU ETS provides a market price for carbon in the European Union. The Dutch Carbon Tax acts as a floor to the EU ETS and will rise linearly from €30/tCO_2 in 2021 to €125/tCO_2 by 2030. The legislated value of the Carbon Tax is expressed in nominal terms. It was converted to real terms for the cash flow by assuming an annual inflation rate of 1.5% for the 2022 to 2030 period. As a result of the carbon tax, the effective carbon price in the Netherlands is the largest between the EU ETS price and the carbon tax level. It is assumed that after 2030 the Dutch Carbon Tax will remain constant in real terms.

The PRIMES Energy system model provides a long-term projection for the EU ETS carbon price.[47] This model, however, does not incorporate the modifications to the EU ETS proposed under the "Fit for 55" package, released in July 2021. Among other measures, the "Fit for 55" package would reduce the free allocation of allowances and lead to an increase in prices. In effect, carbon prices have notably increased in the second half of 2021.[48] Because no up-to-date, long-term projections are available, we assume future EU ETS prices will remain at least as high as the second half of 2021's average price – €62.80/tCO_2. Figure 28 shows the effective carbon price for the Netherlands that has been assumed for the economic assessment.

[47] EU Commission, 2021, *PRIMES Energy system model* in *EU Reference Scenario 2020*.
[48] The proposed reduction in the cap is one of the factors behind the increase in the EU ETS carbon price. Other factors, such as the post-COVID recovery, have also contributed.

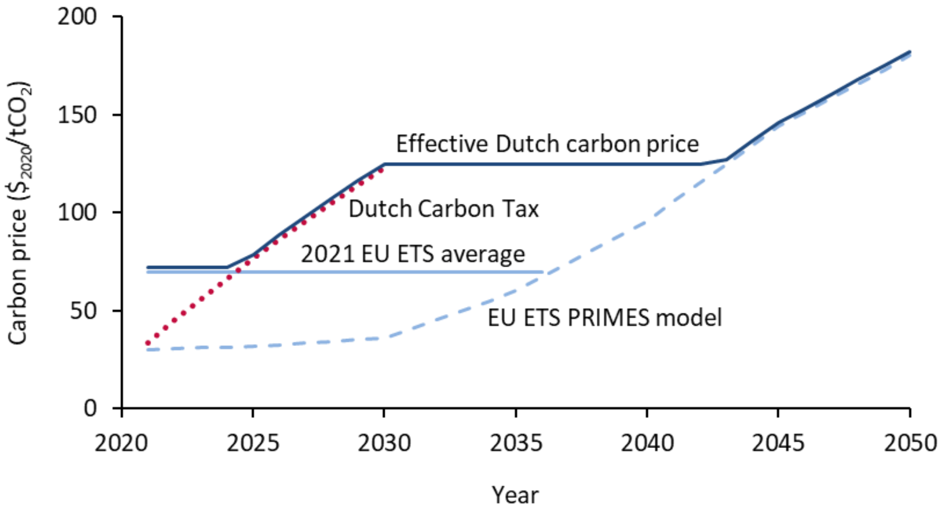


Figure 28: Dutch carbon price projections used for policy modelling

California

In California, the Cap-and-Trade Program covers sources responsible for around 80% of the state's GHG emissions. The California Energy Commission provides a price projection up to 2030.[49] For the longer term, carbon price projections for the USA are not covered by the IEA World Energy Outlook. Instead, we have used projections for developed countries from the BP Energy Outlook. The Cap-and-Trade Program weighted average price from 2020, \$17.04/tCO_2, was used as a starting point. Values from the Mid-Price scenario from the California Energy Commission were adjusted to incorporate the Cap-and-Trade Program weighted average price from 2020, \$17.04/tCO_2. An average between the BAU and the Rapid scenarios from the BP Energy Outlook was used for the outward trend from 2030 to 2050, assuming that the ratio between both projections remains constant. As for Texas, it has not implemented any sort of carbon pricing. Texas is included as a case of zero carbon pricing.

China

In China, after the trial of several ETS pilots China's national ETS started operating in 2021. Currently, it covers companies from the power sector only, but the system's scope is to be expanded. For the purpose of this study it is assumed that emissions from lime kilns are covered. It is an intensity-based ETS, meaning that rather than setting an absolute cap this is linked to the power generation output. The carbon price averaged CNY 46.60/tCO_2 in 2021 (\$6.83/tCO_2). The projection follows the IEA World Energy Outlook STEPS scenario.

Inclusion thresholds

Interestingly, all of the emissions trading schemes have an inclusion threshold. Emitters falling below that threshold are not required to trade allowances. Hence, they do not receive any incentive to install a capture plant. The inclusion threshold for the EU ETS varies by sector. For power generation, the threshold is set at a capacity of 20 MW_{th}. For a high capacity factor of 85%, 20 MWth roughly represents 30 ktCO_2/year.[50] In the case of the California Cap-and-Trade Program, the inclusion threshold is 25 ktCO_2/year. This is very close to the inclusion threshold for the Chinese National ETS, of 26 ktCO_2/year. **Hence, as soon as the scale of a site gets below 25 to 30 ktCO_2/year it stops receiving any sort of incentives from carbon pricing for all the regions analysed**.

[49] California Energy Commission, 2017, *Preliminary GHG Price Projections*.
[50] Assuming specific direct emissions from burning natural gas of 200 kgCO_2/MWh LHV.

It should be noted that a Carbon Border Adjustment Mechanism (CBAM) has recently been legislated in the European Union and is also being proposed in the Unites States. The CBAM is a carbon border tariff that would require importers of carbon intensive goods, which includes lime, to purchase certificates for each tonne of carbon emissions embedded in their goods, at a value determined by the difference between the EU ETS and the price of carbon already paid by the exporter. A CBAM could give an additional incentive to decarbonise to avoid paying the import tariff. Its effect, however, will not be modelled within this study.

Construction phase support

Construction phase support can take different forms:

- **Capital grants** which decrease the project costs and reduce the need for third party financing – they might even allow emitters to finance the project from their balance sheet;
- **Public loans** that offer a lower interest rate than the market one lower the WACC, and thus the cost of capital and the hurdle rate are reduced;
- **Loan guarantees** in which the risk of default on loan repayment is borne by the government, that becomes responsible to repay the creditors if the project fails but faces no cost if it is successful.

Capital grants are the focus of the capital support incentives in this study. The effect of public loans or loan guarantees in reducing the cost of capital have not been modelled. Capital grants can take two basic forms. In a match-funded approach funding is paid proportionally to private funding from other sources. We have assumed that match funding covers 50% of the project cost. By contrast, in a last-spend approach industry is set to raise as much private capital as possible, and then the funding gap to fully finance the project is covered by a capital grant. The proposed Industrial Carbon Capture (ICC) business model in the UK,[51] for example, intends to provide capital grant support on a last spend basis

Revenue support

Revenues from carbon pricing may be insufficient to incentivise carbon capture. Revenue support recognises the difference between the cost of capture and the carbon price by providing an operating subsidy. In the Netherlands, the SDE++ subsidy is an example of revenue support for industrial processes with carbon capture that provides a compensation that covers the unsupported cost of capture – the portion of the capture cost above revenues or avoided costs. For a duration of 15 years, the subsidy is determined as the difference between the application amount – i.e., the cost of capture, including a return on capital – and the revenues from trading CO_2 emission allowances under the EU ETS. It works as a contract for difference (CfD). The expectation is that after the duration of the subsidy ends the EU ETS revenues would be sufficient to cover the cost of capture. The SDE++ revenue support scheme is applicable to industrial CO_2 capture, including waste incineration plants. It is, however, not applicable to straightforward power production.

An alternative revenue support model could include separate OPEX and CAPEX payments, where the CAPEX payments only take place during the first few years of operation as shown in Figure 29. This could better align with debt servicing payments. An example of such a model is the proposed ICC business model in the UK. For the case studies and regions where the level of incentives is insufficient to make carbon capture economically attractive, we assess the level of support that would be required under OPEX and CAPEX payments, assuming that OPEX payments are available for the entire lifetime of the investment.

[51] The proposed ICC business model is not final and is subject to further development by the UK government. Retrieved from https://www.gov.uk/government/publications/carbon-capture-usage-and-storage-ccus-business-models

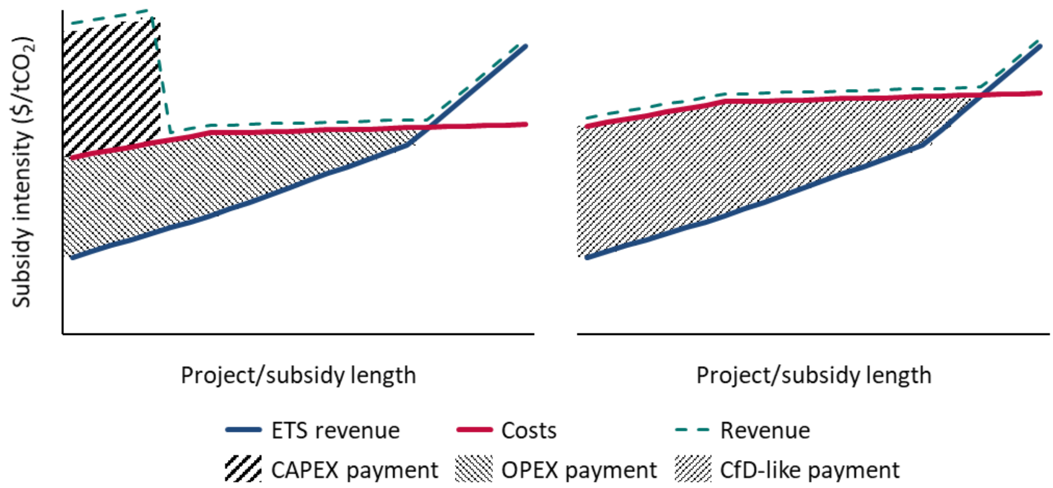


Figure 29: Comparison of revenue support mechanisms[52]

Tax credit

Tax credits are an alternative way of unlocking investment in carbon capture. In the US, the 45Q carbon oxide sequestration credit, named after the relevant section in the US tax code, provides a federal monetary credit for permanently stored CO_2. By 2026, projects will be able to receive \$50/tCO_2 for geologic storage, and it will increase with inflation afterwards. Compared to emissions trading, it has the advantage of not being subject to price volatility. Moreover, it can be combined with state incentives and with the trading of allowances – i.e., with the California Cap-and-Trade Program. Because the value of the tax credit up to 2026 is expressed in nominal terms, it was adjusted to real terms following the Energy Information Administration projections.[53] Importantly, tax credits would be available for 12 years, beginning when the carbon capture plants start operation.[54]

The success of the tax credit 45Q in unlocking investment in carbon capture has spurred proposals to rise the value of the credit. The Build Back Better (BBB) Act, passed by the House of Representatives in November 2021, would increase the credit to \$85/tCO_2.[55] Figure 30 illustrates tax credit 45Q compared to the credit value according to the BBB Act. A tax credit of \$85/tCO_2 will be compared against the required value of the tax credit for investors to breakeven. The effect of extending the duration of the tax credits will also be assessed.

[52] Capture costs seem to be higher under a CfD-like subsidy because the subsidy also covers a return on the capital, whereas in the split CAPEX and OPEX payment model the OPEX payment only covers operational expenditures.
[53] The EIA projections (https://www.eia.gov/analysis/projection-data.php#annualproj) are expressed both in nominal dollars and in 2020 dollars. The ratio between the two was used to adjust the tax credit value.
[54] The ability to claim tax credits depends on the developer being profitable enough, but tax equity partnerships have emerged to allow developers to secure financing and to share in the tax credits.
[55] Tax credit 45Q would still be available for a period of 12 years under the Build Back Better Act. Other proposals that also mention a value of \$85/tCO_2 are the CATCH Act (SB 2230), introduced in the Senate in June 2021, or Bill HR 2633, introduced in the House of Representatives in April 2021.

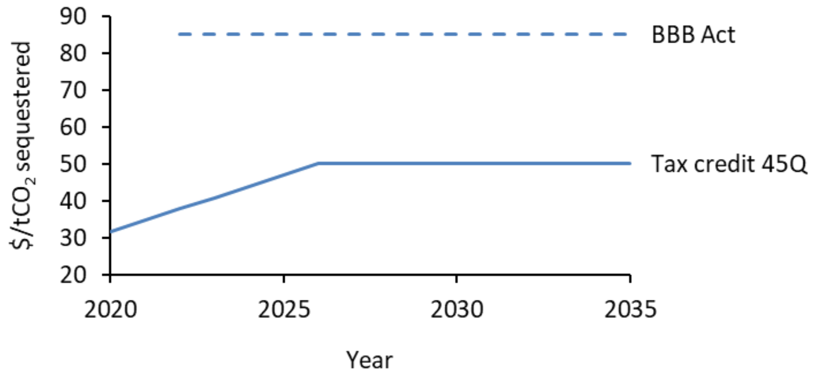


Figure 30: Current tax credit 45Q compared to its modification by the BBB Act

As with carbon pricing, the scale of the emitters that are targeted by the tax credits reveals the extent to which small-scale plants are incentivised to capture carbon. With the credit 45Q, only plants capturing more than 25 ktCO_2/year are considered qualified facilities that can claim the credit. This size belongs to the same range as the one covered by the different carbon pricing systems. Interestingly, modifications to tax credit 45Q under the BBB Act would lower the inclusion threshold to 12.5 ktCO_2/year for non-electricity producing facilities and to 18.75 ktCO_2/year for electricity producing facilities.

5.1.2 Economic modelling

Table 24 contains the values of some of the parameters that were used for the cash flow. A hurdle rate of 10% was used for the emitters. This value is in real terms and before tax, as its legislation varies considerably across the regions focus of this study and thus taxation was not included. The discounted decommissioning cost at the end of the lifetime is assumed to be negligible. Alternative uses of the captured CO_2 such as enhanced oil recovery (EOR) are not included. Box 2 presents some additional considerations around the T&S fees for geological storage.

Table 24: Parameters used

Parameter	Value
Lifetime	25 years
Hurdle rate	10%
T&S fee	\$40/tCO_2
Decommissioning cost	-

Box 2 – Transport and storage fees

Whilst an analysis of transport and storage (T&S) costs is beyond the purpose of this report, **T&S is an integral part of the CCS value chain** and its cost needs to be adequately accounted for. Proposed pricing mechanisms for T&S include charging a fixed rate per year plus a variable rate for each tonne of CO_2 injected to the network. T&S fees are likely to show a large variation between different global regions and even at a local level. The distance from the power plant or industrial site to the geological storage and the presence or not of economies of scale for T&S – either from large-scale emitters or from clustered CO_2 capture – explain the variation.

As a simplification, we have **assumed a constant T&S fee of $40/tCO$_2$** for the different geographies. This value could be low or high depending on specific local and regional conditions. As a result, projects that could seem not to be attractive under the present modelling could be profitable if actual T&S fees were lower than the one considered.

Small-scale sites are likely to face higher T&S fees per tonne of CO_2 than large capture plants. First, in a unit basis they will be exposed to higher connection costs and, hence, fixed rates. Second, small-scale sites are more likely to be dispersed and lack access to T&S networks around anchor emitters. If that is the case, then the T&S cost could climb well above $40/tCO$_2$.

As an additional simplification, all capital expenditures are assumed to be disbursed at Year 0 and the capture plant is operational during all of Year 1 – i.e., 2023. Debt servicing is not included in the cash flow. It is assumed that capital will be repaid over the entire lifetime of the project or, when policy support is only available during an initial period, over the duration of the policy support mechanism used to repay capital.

Regional differences

The costs of carbon capture are affected by local factors, and thus depend on the capture plant location. The effects of the plant location on the costs of carbon capture have already been studied by the IEAGHG.[56] For the purpose of this analysis, we consider three sources of regional differences:

- **The cost of energy** required to run the capture plant, which is derived from energy price projections as described in Section 4.1;
- **Current and proposed policies for each region**, as described either by government documents or reported by various articles;
- **Product prices** – i.e., lime price –, used to analyse the impact of carbon capture on product prices.

Other geographically varying factors may need to be considered for site-specific analyses, including ambient conditions, fuel composition, water availability, labour costs and productivity, local costs of materials, and the solvent management costs associated to compliance with local environmental regulations. These were not included in the present analysis.

[56] IEAGHG, 2018, *Effects of Plant Location on the Costs of CO_2 Capture*, Technical Report 2018-04.

5.2 Policy impact on the economics of small-scale capture

Two of the case studies were progressed to evaluate the impact of current and proposed policies and incentives in establishing an economically viable case for deployment of CO_2 capture. The two case studies analysed in this section are the small-scale CCGT and the lime kiln. We have also included the large-scale analogue for the CCGT. The case studies were selected to include one power and one industrial application representative of a wide range of capture costs and different heat supply strategies. If similar results are obtained from the case studies despite their differences, then the findings can be generalised to a broad range of applications. The analysis focuses on the Netherlands as the base case and will explore policies in two states in the United States with very different approaches to CCS – California and Texas – and in China. We will first assess the level of support offered by current policies and incentives. We will then present what the required level of support to establish an economically viable case would be, before presenting alternative incentives that have been proposed elsewhere.

5.2.1 Current policies and incentives

The results show that, whilst current policies can make large-scale capture attractive in some jurisdictions, they are not sufficient to incentivise small-scale capture. To allow for a comparison between capture plants with different capital requirements the NPV is normalised by the discounted cumulative CO_2 captured over the investment lifetime. The result is a normalised NPV expressed in \$/tCO_2. Figure 31 presents the normalised NPV of capture plants for different emitters and regions. Only in the Netherlands could small-scale capture projects be able to break even for a broad range of industrial applications. This is explained by the relatively higher carbon prices and the revenue support that help to recover capital. In other regions, even when capture from a large-scale CCGT could be profitable – as in California – small-scale capture receives insufficient incentives.

Capture from a large-scale CCGT, a small-scale CCGT and from a lime kiln are decreasingly attractive capture proposals. A one-size-fits-all approach to encouraging the deployment of capture plants reveals a gap for small-scale plants. If small-scale carbon capture is to be incentivised, a tailored approach is required.

It should be noted that the SDE++ does not apply to CCGTs. In spite of this, we have modelled CCGTs in the Netherlands under the assumption that SDE++ could apply to power CCS to assess what its impact would be.

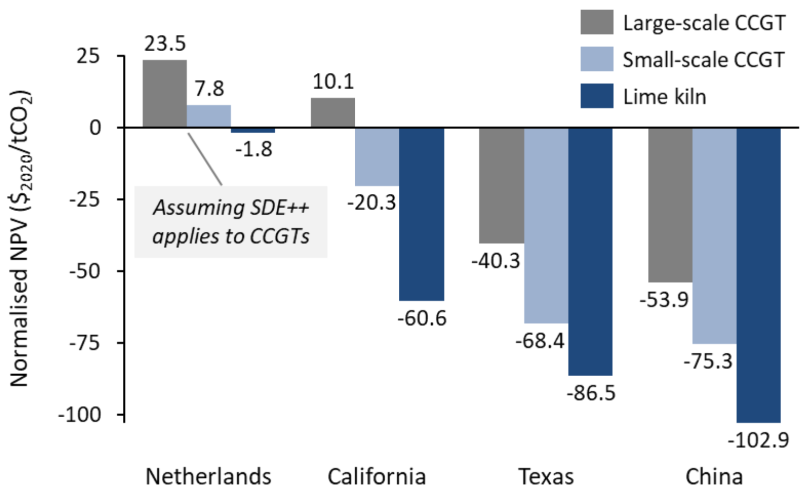


Figure 31: Regional comparison of normalised NPV for different capture applications

Small-scale CCGT

The cash flows for each region focus of this analysis evidence striking differences, as shown in Figure 32. In the Netherlands, despite high energy prices, a capture plant for a small-scale CCGT can make an attractive business case. Assuming that SDE++ or other revenue support apply to CCGTs, the high level of the carbon price would only require marginal contributions from revenue support. These contributions are limited to the first few years of operation. By the time the subsidy is phased out after 15 years the avoided carbon cost is sufficient to cover the operational expenditures and turn a profit. Hence, there is no discontinuity in the net income. In this case, the SDE++ contributes to more than 90% of the levelised revenues, represented in Figure 33.

In California, carbon prices are complemented by tax credit 45Q for the first 12 years of operation. Despite this, the net income[57] remains negative during the first few years of operation. Whilst an increase in carbon prices allows to cover operational expenditures after that, this is still insufficient to repay the investment. In particular, when the capture plant loses support from the tax credit avoided carbon costs are barely enough to cover the OPEX. The IRR for this case is 7%, lower than the hurdle rate. Moreover, it can be seen that whilst the carbon price after 2040 is close to the one in the Netherlands, the levelised revenues from carbon pricing is much lower, largely due to heavier discounting of future cash flows.

In the case of Texas, the capture cost is markedly lower than in other regions. However, the tax credit 45Q alone is insufficient to cover the operational expenditures, let alone repay the capital. After the fiscal benefit is over, all revenue sources are lost. Unless other incentives are implemented, an alternative revenue source is needed to economically justify capture plants.

China constitutes a very different case. Carbon prices under the National ETS would not be sufficient to cover the operational expenditures at any point in the lifetime of the capture plant. This implies that capital grant would not suffice to make an attractive business case regardless of their magnitude.

[57] Net income (before interest, taxes, depreciation, and amortisation) defined as revenues – or avoided costs – minus operating costs.

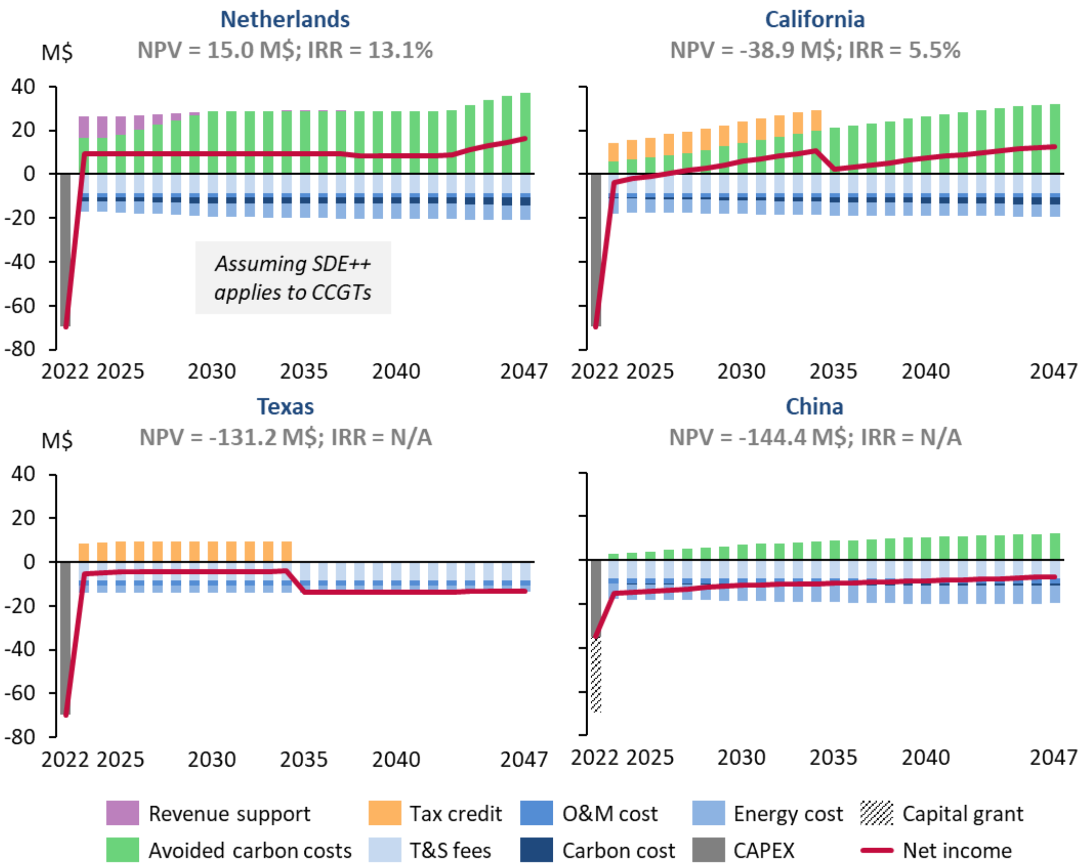


Figure 32: Cash flows for carbon capture from a 100 MWe CCGT

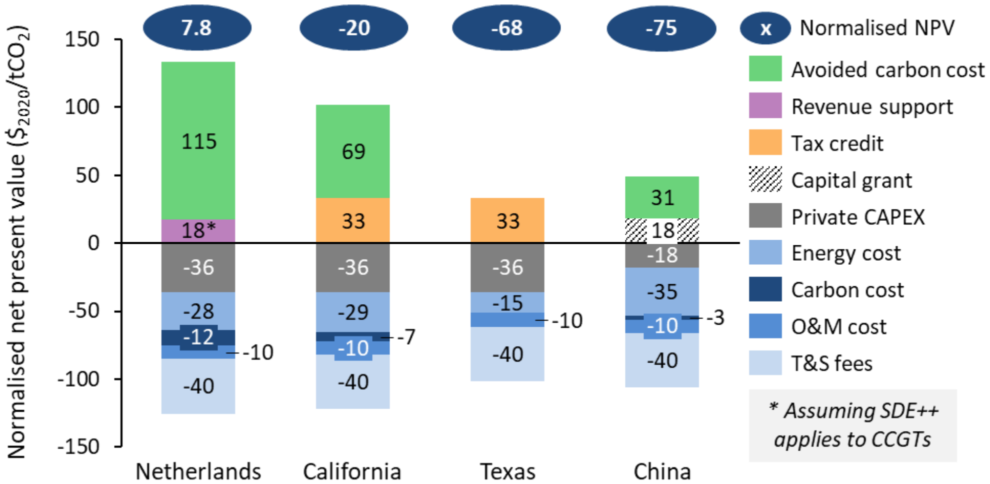


Figure 33: Breakdown of normalised NPV value for carbon capture from a 100 MWe CCGT

Large-scale CCGT

The small-scale CCGT was compared with its large-scale analogue for the Netherlands and California. As illustrated in the cash flows in Figure 34, both jurisdictions show a largely positive NPV. Under the carbon and energy price projections, the current policies result in an attractive economic proposition. In the Netherlands, revenue support would play a minor role in total revenues[Error! Bookmark not defined.], but gives certainty to repay the capital investment in the first few years of operation. With a discounted payback period of 6 years, it is a more attractive option than capturing from the small-scale CCGT. In

California, the tax credit 45Q effectively complements the Cap-and-Trade program. By the second year of operation, the two revenue sources cover operational expenditures. Moreover, with a discounted payback period of 10 years by the time the fiscal benefit no longer applies carbon pricing suffices to run a profitable capture plant. This contrasts starkly with the cash flow from Figure 32.

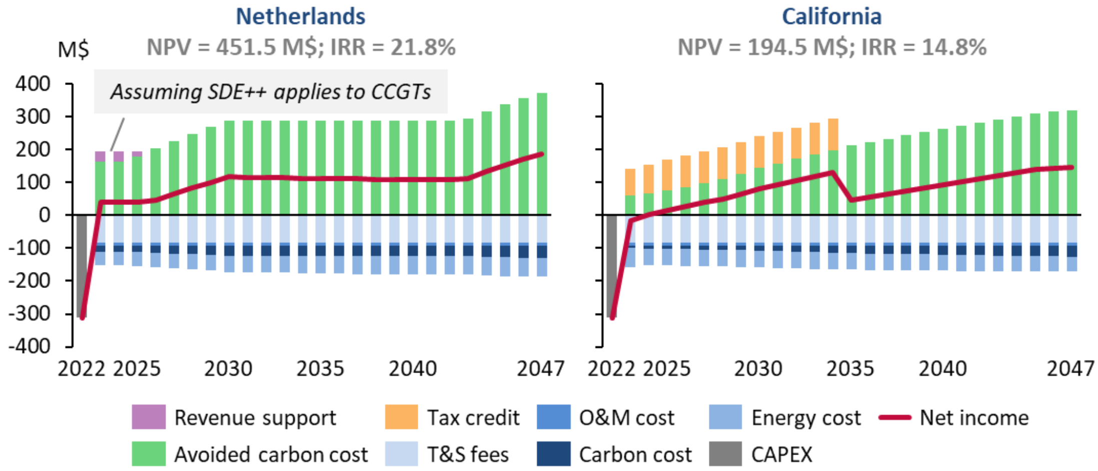


Figure 34: Cash flows for carbon capture from a 1,000 MWe CCGT

Lime kiln

Current policies and incentives do not succeed in making the capture of carbon from a lime kiln economically attractive for any of the regions focus of this study. The gap in support, however, varies by region. The cash flows in Figure 35 expounds the differences. In the Netherlands, revenue support under the SDE++ complements the avoided carbon cost and, by the end of the duration of the support mechanism, allows an investor to breakeven. The SDE++ reveals its flexibility in effectively supporting carbon capture under different costs of capture. This flexibility can be seen in Figure 36: the SDE++ subsidy is a far more important component of total revenues than for a small-scale CCGT (Figure 33). Nonetheless, the high dependence on the subsidy signifies that its end represents a cliff in revenues; avoided carbon costs would not serve to cover operational expenditures. Only by the very end of the lifetime does carbon pricing cover the OPEX. As a result, whilst the NPV is only marginally negative, the end of the SDE++ subsidy could lead to early termination of the capture plant's operation. If small-scale industrial carbon capture is to be encouraged, extended support would be required.

In the other regions, policies are clearly insufficient to incentivise carbon capture from a lime kiln. Only in California does the net income eventually become positive, as the tax credit 45Q aids to cover some OPEX. However, the end of tax credit 45Q reverts the slow increase in the net income. As with the SDE++ subsidy in the Netherlands, the end of the fiscal benefit begets an abrupt drop in revenues for a capture plant operator. Even if the tax credit was to be increased, by the time the capture plant no longer qualifies to continue receiving it its closedown would be brought forward.

A small-scale capture plant for a lime kiln in China would be more strongly loss-making than in Texas, despite carbon pricing and the access to capital grants. As Figure 36 shows, levelised revenues are higher in China. However, high energy prices compared to Texas mean more intensive policy support is required.

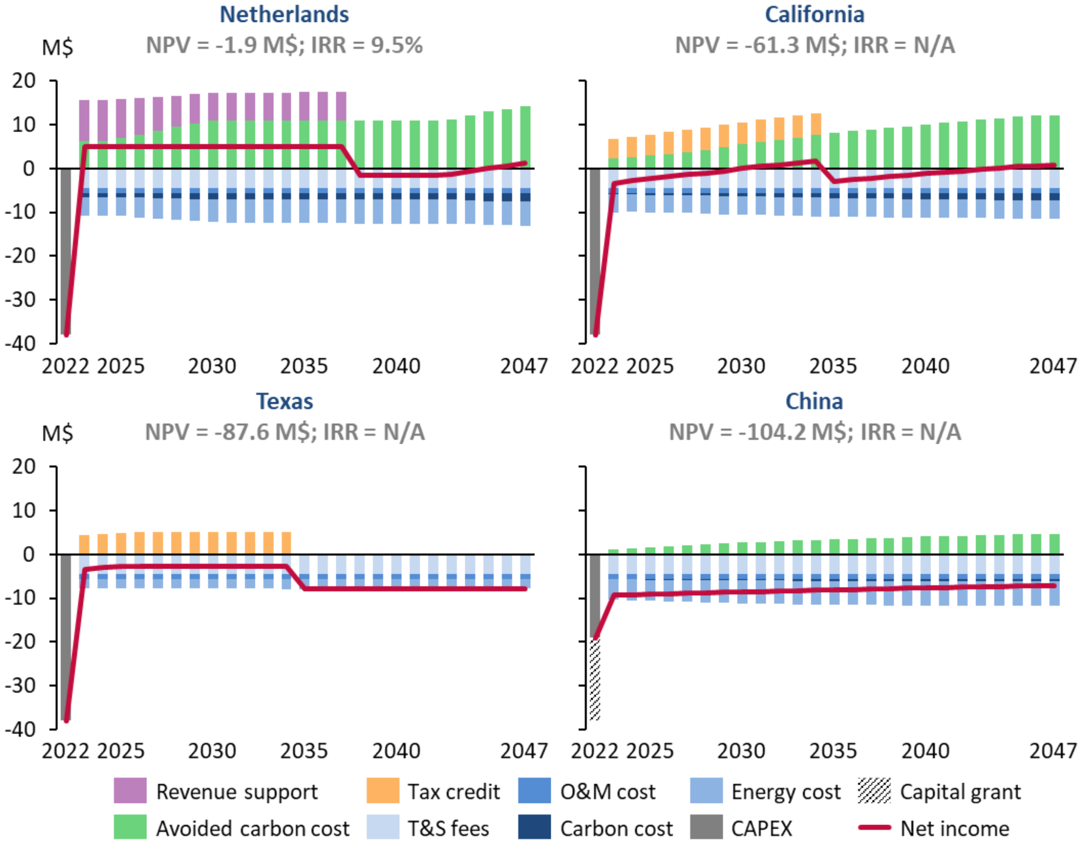


Figure 35: Cash flows for carbon capture from a lime kiln

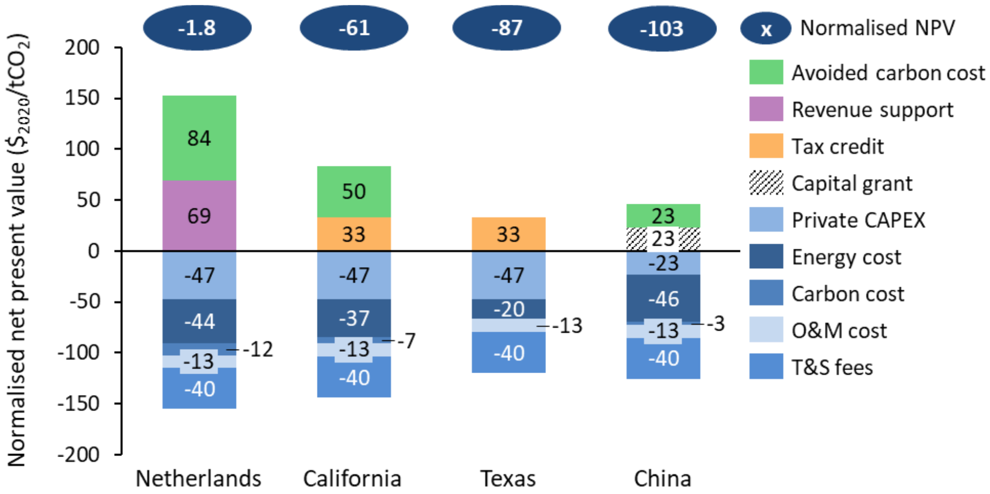


Figure 36: Breakdown of normalised NPV by source for carbon capture from a lime kiln

Because incentives are insufficient for a lime kiln capture plant operator to break even, if capture plants were to be deployed the unsupported cost of capture – the portion of the capture cost above revenues or avoided costs – would need to be passed on to the consumers. The subsequent increase in the price of lime would be largest where the policy gap is biggest. Figure 37 illustrates this, as it can be seen that the lime price increase could be as high as 65% in China. This increase does not reflect additional increases tied to energy prices and the phasing out of free allowances.

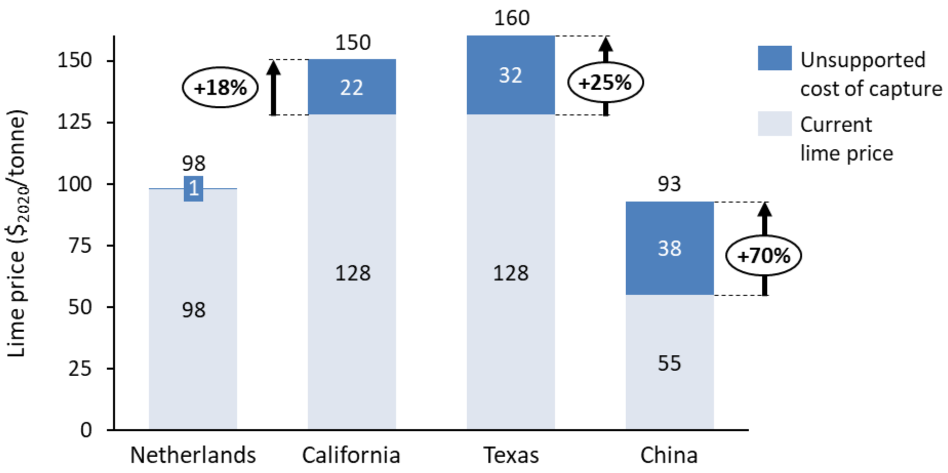


Figure 37: Impact of carbon capture on lime prices[58]

5.2.2 Required level of support

The assessment of current policies and incentives uncovers gaps to support small-scale capture. Those gaps can be classified under three categories:

- **Insufficient level of support**, as instruments offering a uniform incentive for all emitters result insufficient for small-scale capture plants;
- **Short duration of some policy instruments**, as carbon pricing is still insufficient to cover operational expenditures by the end of the support;
- **Lack of policy instruments**; as additional incentives will be required to complement carbon pricing or tax credits.

We will analyse each of these in turn to develop an understanding of the level of support that would be required to make small-scale capture attractive from an economic perspective. In doing so, the required level of support is contrasted with current policies to quantify the gap.

Breakeven carbon price – or tax credit

Carbon pricing and tax credits establish a single value per tonne of CO_2 for all emitters. Whilst that price or credit will be sufficient for some capture proposals, others would require higher prices to be investable. Figure 38 shows the breakeven carbon price for the different case studies and regions for two scenarios: when carbon pricing is the only incentive and when it is combined with existing policies. The assumed carbon price projection average is included as a reference. The range of breakeven prices reflects the uncertainty of energy prices – they include Low, Mid and High energy costs. Low and High energy costs are 50% and 150% of the projected costs – the Mid energy costs – respectively. With carbon pricing alone, projected carbon prices would only suffice to incentivise carbon capture from large-scale CCGT plants in the Netherlands and, depending on the evolution of energy prices, perhaps from small-scale CCGT plants as well. However, as mentioned before this assumes that the SDE++ is applicable to CCGTs. For all other cases, the breakeven carbon price is much higher than the projected ones. When current policies are taken into consideration the gap is reduced. However, the gap is still significant for small-scale CCGT plants in Texas and China, and for lime kilns in all regions.

[58] Current lime prices are ex-works quicklime prices. The price for Netherlands is the EU-27 average from the Eurostat Prodcom Annual Database; for China, it was obtained from a market report by CW Research; for the United States, it was obtained from the 2021 Mineral Commodity Summary from the US Geological Survey.

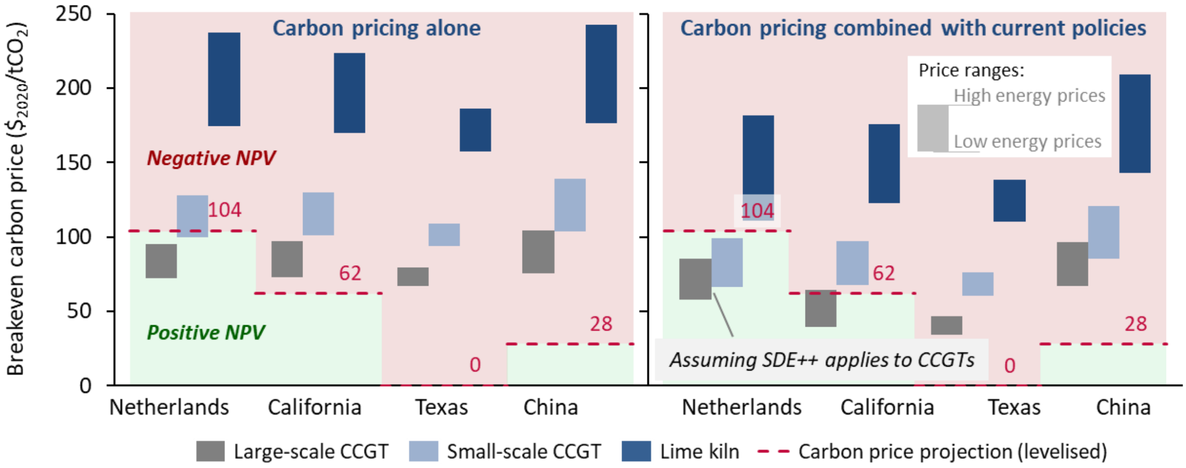


Figure 38: Range of carbon prices required to breakeven for different capture applications, and effect of complementing with other policies

In regions where a tax credit is in place, the alternative to higher carbon prices would be to increase the tax credit value. Such an example is the BBB Act, that would rise the tax credit to $85/t$CO_2$. Figure 39 displays the breakeven tax credit values for California and Texas, assuming that it is combined with other incentives such as the Californian Cap-and-Trade program. In California, the implementation of the BBB Act could make capture from small-scale CCGT plants attractive, but the breakeven tax credit for more expensive capture proposals – i.e., a lime kiln – is well above 45Q and even the BBB Act value. Where there is no carbon pricing, such as in Texas, the breakeven tax credit is higher than the BBB Act, including for the CCGT large-scale analogue. Under those conditions, the only way to justify capture from an economic perspective is the access to alternative revenue sources.

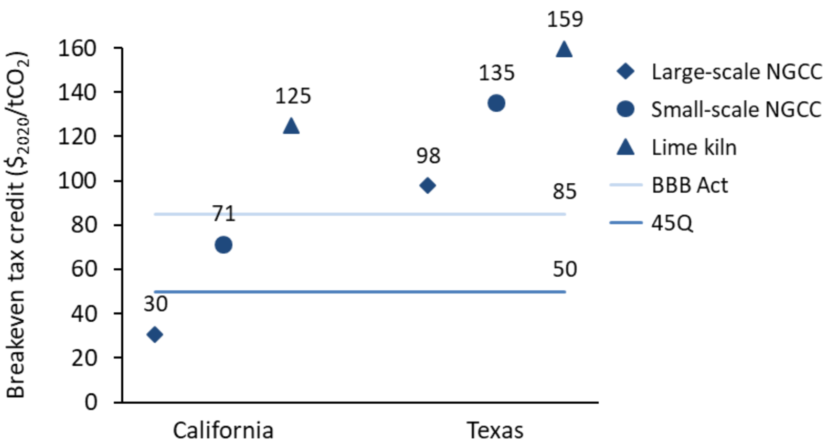


Figure 39: Value of the tax credit required to breakeven for different capture applications

Alternative incentives

As discussed above, supporting small-scale capture by further increasing carbon prices or tax credits would require values much higher than current projections. The alternatives include extending the duration of other support mechanisms or introducing flexible revenue support where it is not in place – where the level of support depends on the gap between the carbon price and the cost of capture.

Figure 40 displays how such alternatives could support capture from a small-scale CCGT. There would be no difference in the Netherlands, as there is no need of additional support by the time the SDE++ subsidy expires. In California, the extension of tax credit 45Q to the entire lifetime of the capture plant would eliminate the current strong drop in net income plants would face but a small-scale capture project would still not break even. In Texas, the extension of the tax credit would not be enough as operational expenditures would remain uncovered. As carbon prices in China are too low to cover costs further incentives would be required. Hence, the introduction of CfD-like subsidies offering revenue support could make capture attractive. Such a subsidy, extended to the entire lifetime of the capture plant (or until carbon prices are high enough), would allow small-scale capture projects to break even. As shown in Figure 41, revenue support would constitute a large share (over 55%) of total revenues for a Chinese operator.

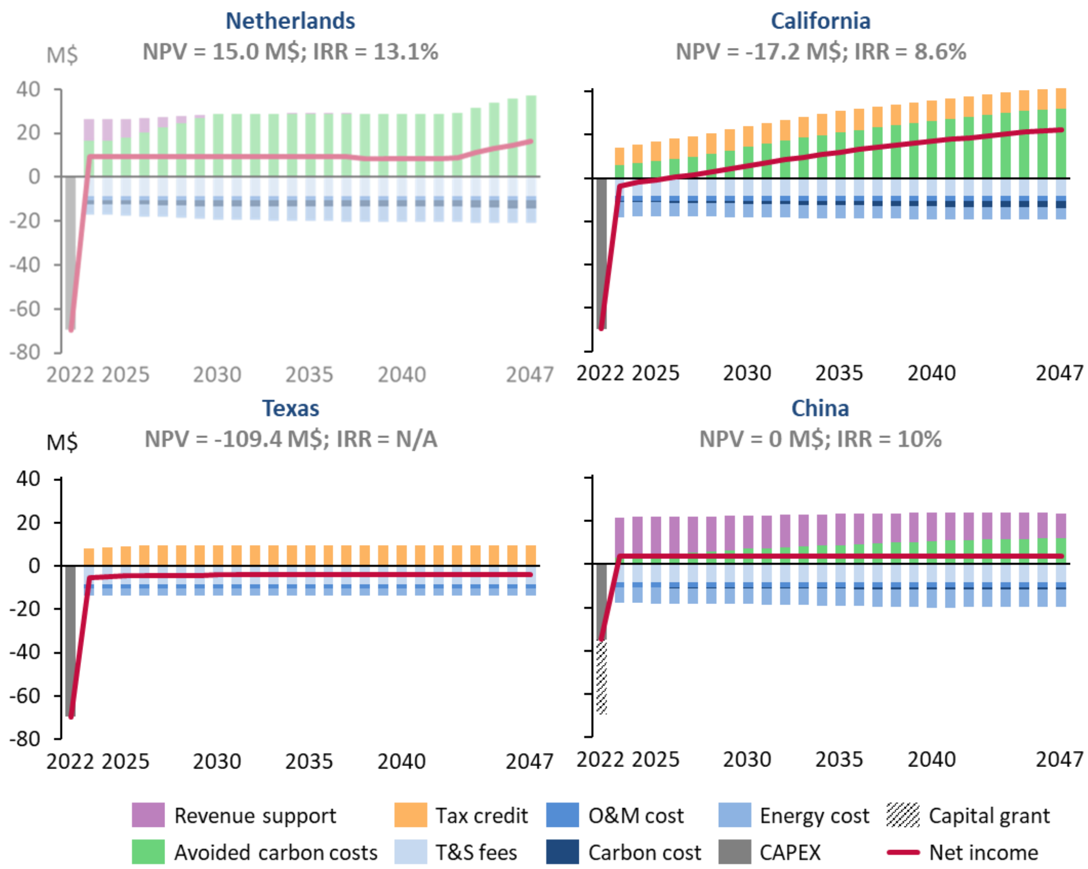


Figure 40: Cash flows for carbon capture from a 100 MWe CCGT, assuming incentives are extended in time or complemented by alternatives

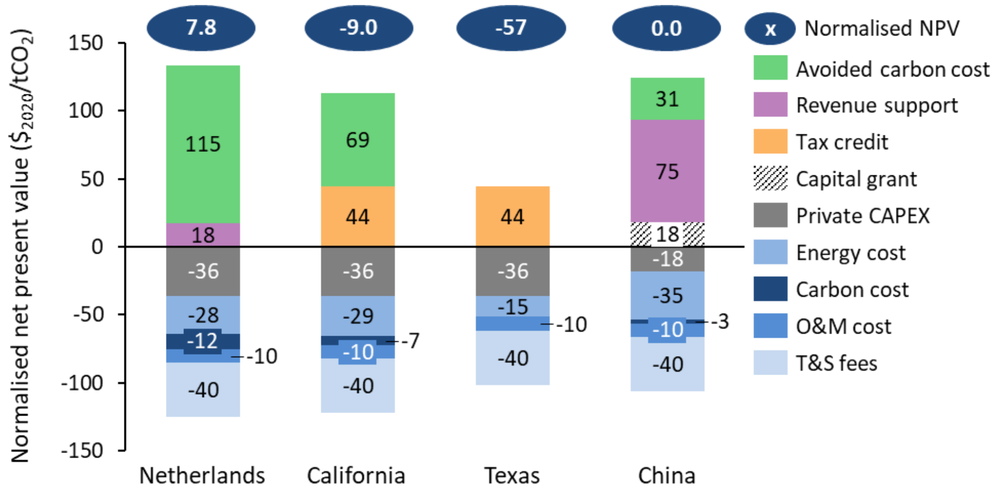


Figure 41: Breakdown of normalised NPV by source for carbon capture from a 100 MWe CCGT, assuming incentives are extended in time or complemented by alternatives

Figure 42 depicts the cash flows under the same alternative incentives but for a lime kiln capture plant. The extension of the SDE++ subsidy in the Netherlands would avoid the potential early end of operation of the capture plant that arises from Figure 35. In the United States, the rigid nature of the tax credit 45Q – in which all emitters receive the fiscal benefit for the same value – shows its limitations even when its duration is extended. The NPV in California still remains largely negative (with a non-existent IRR), and in Texas the net income is negative all throughout the lifetime of the capture plant. The introduction of a 25-year long CfD-like subsidy in China would make capture from a lime kiln attractive. However, as it can be seen from Figure 43 the subsidy would completely dominate the revenues, representing more than two thirds of the levelised revenues.

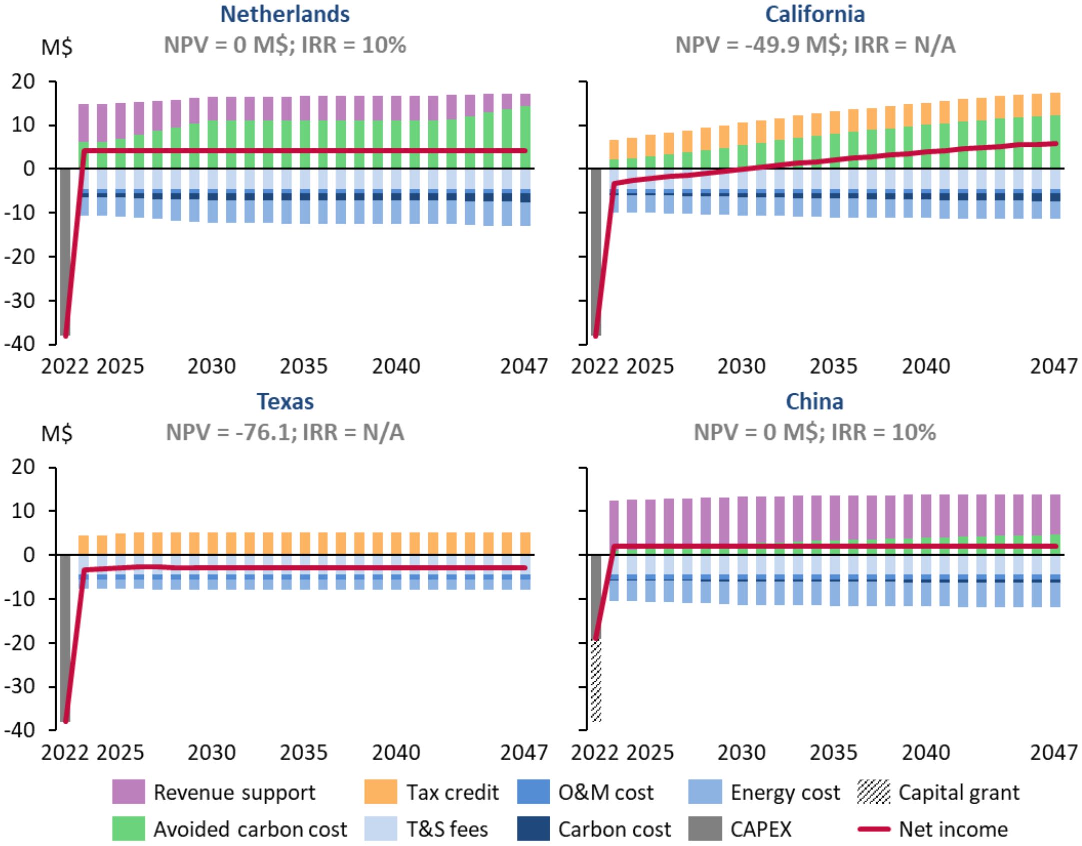


Figure 42: Cash flows for carbon capture from a lime kiln, assuming incentives are extended in time or complemented by alternatives

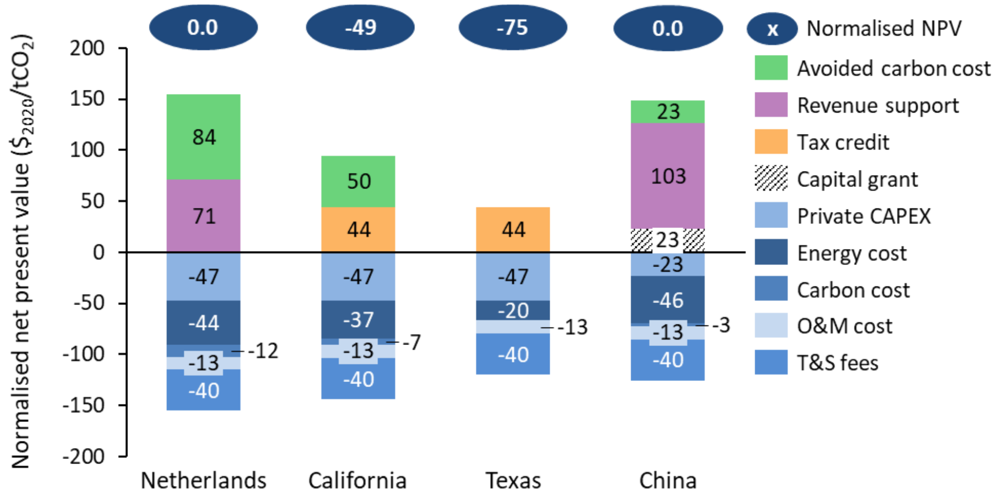


Figure 43: Breakdown of net present value by source for carbon capture from a lime kiln, assuming incentives are extended in time or complemented by alternatives

An additional alternative is explored for a Dutch lime kiln. A split revenue support model, of which the proposed Industrial Carbon Capture (ICC) business model in the UK is an example, would include separate CAPEX payments for the first 5 years of operation and OPEX difference payments for all the lifetime (or until carbon prices are high enough).[59] Whilst the NPV does not reflect any significant difference with the extension of the SDE++ subsidy, the CAPEX repayment can mirror in a closer way

[59] Note that the ICC business model would offer OPEX payments for up to 15 years.

the likely loan repayments that a firm would need to incur in to cover the private CAPEX. Figure 44 illustrates the alternative and shows how the dependence on subsidies is significantly reduced once the CAPEX is paid for.

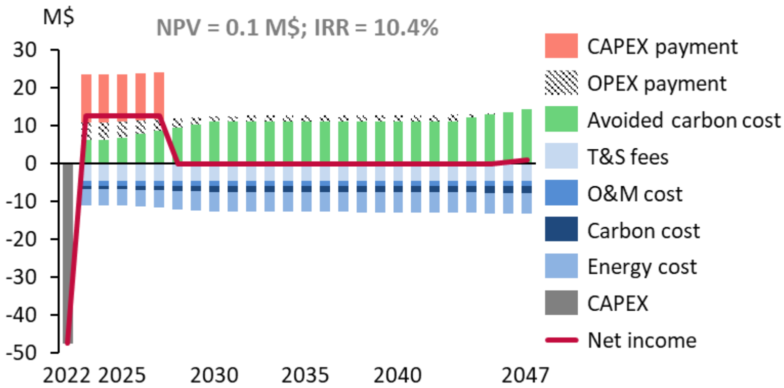


Figure 44: Cash flow for carbon capture from a lime kiln in the Netherlands with split CAPEX and OPEX support

6 Barriers and enablers for small-scale capture deployment

Chapters 3 to 5 have presented qualitative and quantitative implications of deploying small-scale capture plants, supported by a TEA and a policy assessment. Having considered each aspect separately, this Chapter aims to review the barriers and enablers for small-scale capture.

6.1 Barriers to deployment

Small-scale capture faces several barriers and challenges that will need to be overcome if deployment is to be facilitated. Whilst many of these also apply for CCS deployment in general, they are likely to affect small-scale capture to a greater degree. Governments, industries, academia, and technology developers should seek to address:

- **Lack of small-scale-specific research, development, and demonstration**: There are gaps in publicly available literature and data on small-scale capture applications. Parties interested in the sector are hence forced into disjointed efforts to deploy CCS, ignoring potential synergies and collaboration opportunities.
- **Lack of dedicated CO_2 infrastructure**: Without access to storage, the growth in small-scale capture will be reserved to niche utilisation cases. Whilst this barrier is not exclusive to small-scale capture, it affects the sector to a greater degree for two reasons. First, private-led infrastructure construction can be prohibitively expensive for small CO_2 volumes. Even if a plant is within a CCS hub, network connection costs could be very high unless it sits on the immediacy of the pipeline. Second, small-scale plants tend to be dispersed and away from anchor emitters.
- **Escalating costs as economies of scale evaporate**: For small-scale applications carbon capture is significantly more expensive and capital intensive than for their large-scale analogues. Under current price projections, carbon pricing alone is not enough to establish an economically viable case for small-scale carbon capture.
- **Comparative advantage of alternative decarbonisation strategies**: Less capital-intensive strategies, such as electrification, could have a comparative advantage at smaller scales. Small-scale carbon capture is thus particularly relevant for sectors with either the presence of process emissions, the use of internal fuels, or that could lead to negative emissions if coupled with CCS.

6.2 Enablers for deployment

Despite the hurdles, deployment of carbon capture on small scale applications could become attractive for investors under certain conditions. **A combination of low energy costs, high carbon prices, and additional incentives through revenue support mechanisms can unlock investment in small-scale capture**. Although this ideal situation is unlikely to be met, even partial fulfilment could result attractive. For instance, despite the elevated energy prices in the Netherlands some small-scale capture proposals can be appealing for investors. This is because of the high carbon prices and the SDE++ subsidy, that covers the difference between the cost of capture and the effective carbon price. Where these conditions are not met, alternative revenue opportunities, such as utilisation or EOR, could help build a business case for the sector. The market for CO_2 utilisation can be highly relevant for small-scale emitters and it might offer some premiums compared to carbon prices. However, whilst those opportunities improve the economics of carbon capture, they may have lower carbon reduction benefits.

Small-scale carbon capture can be enabled by the simultaneous development of three areas:

- **Development of CCS hubs around anchor emitters**: By linking the development of T&S networks to large-scale emitters, small-scale plants within industrial clusters would transfer the burden for the construction of T&S networks. This would allow them to access the downstream

CO_2 value chain facing lower T&S fees, to reduce their risk exposure, and to effectively decouple carbon capture from CO_2 infrastructure. Utilisation options could also help to fast track pilot plants for technology demonstration prior to achieving wider deployment.

- **Modularisation and standardisation of capture plants**: The containerised approach to the design of capture plants is an enabling technology for small-scale capture plants deployment. The active interest and R&D in modularisation and standardisation of capture plants by many technology developers, although not purposely aimed at small-scale sites, can provide a platform for the growth of CCS for small and medium emitters.
- **Tailored policy support for small-scale capture**: The level of policy support required for small-scale capture is significantly higher than for large-scale plants, and a one-size-fits-all approach results unsuitable. Tailored incentives that move beyond carbon pricing or tax credits can make small-scale carbon capture an attractive economic case.

6.3 Policy support and incentives

The review of recent and proposed policy changes and incentives for the regions focus of this study has highlighted limitations linked to three areas:

- **Scope**: Globally, ETS and tax credits set an inclusion threshold to lower the impact on smaller emitters. Whilst there are variations in the metrics used and the level of the threshold, it was found that for the regions under analysis it oscillates between 25 and 30 $ktCO_2$/year.[60] This threshold is roughly aligned with the commercial interest by technology developers. This is no coincidence, as emitters that are not included under the ETS or the tax credits have fewer incentives to abate their emissions.
- **Duration**: Policies and incentives provide initial support under the expectation that the rise of carbon prices or revenues from alternative sources will suffice to sustain the capture plant's business model after government support expires. The moment at which carbon prices will be enough to yield a positive net income, however, will differ according to the cost of capture. Small-scale capture being more expensive, the duration of current incentives could be too short. Capture plant operators face a cliff in revenues when policy support expires and could lead to an early end of operation of capture units.
- **Flexibility**: Incentives such as carbon pricing and tax credits are rigid, in the sense that their value is uniform across the economy. Rising their value to the levels required to allow investors on small-scale plants to breakeven would involve much higher prices than the ones that are projected. This would bring great knock-on effects on the wider economy. Alternative incentives that provide tailored support, such as the SDE++ subsidy in the Netherlands or the proposed ICC business model in the UK, acknowledge different costs of capture. This model is attractive for small-scale capture where avoidance costs show a broad range.

Policies and incentives that tackle current limitations within each of the above areas would significantly encourage small-scale capture deployments. Without them it will be very challenging to make small-scale carbon capture attractive for some industrial sectors. Whilst small-scale capture has a high cost, it can still be expected to have a lower cost than alternative abatement options as direct air capture. The alternative would be to find ways to pass the additional cost of capture on to the consumers. Considering that this would in some cases result in significative price increases, this option would only be viable for sites able to access customers with a higher willingness to pay. This could be either justified because of specific procurement rules that prioritise decarbonised products ("green

[60] A notable exception would be the modification to tax credit 45Q under the BBB Act halving the threshold.

procurement") or because of growing awareness in end-consumer markets with corresponding increase in demand for green products.

7 Conclusions

This study investigated the economics of carbon capture on small-scale industrial and power applications. It also evaluated whether current and proposed policies and incentives establish an economically viable case for deployment of small-scale capture plants. It was found that there is a significant knowledge gap around small-scale capture, with reference capture costs lacking granularity and a lack of publicly available data on performance for many patented processes. A techno-economic assessment was provided for four case studies spanning power generation and industrial processes for post-combustion chemical absorption. The costs of CO_2 captured, CO_2 avoided, and the impact on the costs of products and services were quantified. **This led to the finding that small-scale capture is significantly more onerous than for the large-scale analogues and that, without policy support, the impact on the cost of products and services is substantial**. It was demonstrated that current policies are insufficient to incentivise small-scale capture – with the exception, to some extent, of the Netherlands – even if they result attractive for large-scale capture. The uniform upwards regulation of carbon pricing or tax credits was found to be generally unsuitable because of a large gap between required and projected prices. Instead, there are two levers that can address the cost premium, incentivise small-scale carbon capture, and reduce the impact on the price of products and services: **an extended duration of support mechanisms and revenue support models to cover the unsupported cost of capture**. Private investment in small-scale capture plants can occur if three enablers are simultaneously unlocked:

- **Development of CCS hubs** shifts the burden of deploying T&S networks away from small emitters.
- **Standardisation and/or modularisation** are further developed to offset the loss of economies of scale.
- **Tailored policies and incentives** are devised which acknowledge and address the cost differential of small-scale capture.

Unless the above are addressed, it is probable that small-scale capture will be limited to niche applications. This would be a concern for the many small-scale emitters with process emissions or using internal fuels; CCS could be their only pathway to decarbonise in a net-zero compatible way.

Based on these conclusions, it is recommended that future work focuses on five areas:

- **Addressing the data gap**: There is a knowledge gap on carbon capture for small-scale applications. More pilots and demonstration projects publishing their results, including a granular break down of performance and costs, would be beneficial for emitters and policy makers alike.
- **Assessment of alternative separation technologies that could potentially be suitable for small-scale capture**: In addition to post-combustion chemical absorption, membrane separation and MCFCs were identified as being suitable for small-scale deployment. This was based on a qualitative analysis on the potential for downscaling or adopting a modular approach. Further assessment is required to understand the cost implications of small-scale capture for these technologies and potential cost reductions, eventually comparing them with the benchmark chemical absorption technology.
- **Comparison with alternative decarbonisation pathways**: At small scales there could be a comparative advantage for less capital-intensive strategies, such as fuel switching. A comparison between alternative decarbonisation pathways is needed to advance the understanding of the scale at which carbon capture becomes less attractive.
- **Comparison of custom-engineered and mass-produced modular capture plants**: The two diverging trends in modularisation are custom-engineered solutions to optimise performance or mass-produced standardised units to optimise manufacture costs. An assessment of the cases

where each approach could become preferrable is required to understand the level of potential cost reductions associated to them. A detailed comparison should also assess the robustness of a standardised approach to site- and application-specific conditions.

- **Policy design for small-scale capture**: This study identified that current policies and incentives will likely fail to stimulate private investment in small-scale capture and suggested potential improvements. Further work is required to incorporate both a public and private perspective, include the impact of capital financing, and understand the social and economic implications of policy decisions.

8 Appendix

8.1 Metrics and databases for small scale definition

There are two alternative approaches to the selection of a metric. By relating the metric to the output of the site, a tailored definition of small scale could be adopted for each industrial sector or power generation mode. Such an output could be MW or MWh for power generation, or tonnes produced for an industrial product. By contrast, the tonnes of CO_2 potentially captured every year are less adapted to each sector but present the advantage of rendering the results more easily comparable. Additionally, the costs of CO_2 capture and avoidance are expressed in $/t$CO_2$ and technology developers offering CO_2 capture plants generally include a nominal capture capacity expressed as tCO_2/year (or, alternatively, tCO_2/day). Hence, this metric enables financial investors and others in the public audience to estimate market values corresponding to CO_2 capture for small-scale plants. However, adopting a metric based on tCO_2/year is not without limitations. Indeed, the operational parameters guiding the sizing of the capture plant equipment, rather than the annual CO_2 being captured, are the flow rates. Hence, two capture plants of equivalent size but with largely different load factors would seem to be very different if considering the tonnes of CO_2 captured every year alone. This is of particular concern for power generation, where a metric reflecting annual CO_2 captured could hide fundamental differences between load-base power generation and peaking plants.

Once a metric is selected, a threshold can determine which sites are considered to be small scale. The Emissions from Large Point Sources from the UK National Atmospheric Emissions Inventory (NAEI) data set was used for the statistical analysis necessary to select a threshold. For a metric related to tCO_2/year, databases of point source emissions from industrial and power sites can steer the level at which such a threshold is set. Examples of such datasets are the NAEI Emissions from Large Point Sources, the European Pollutant Release and Transfer Register (E-PRTR), or the Manufacturing Industry Decarbonisation Data Exchange Network (MIDDEN) database in the Netherlands. An ideal data set would comprise both a wide geographical coverage and a broad range of emitters' sizes. The NAEI Emissions from Large Point Sources, whilst confined to a smaller region than other data sets, covers a broader range of emitters and includes emissions from point sources emitting under 1,000 tCO_2/yearCO_2. This better sampling of sites justifies its selection for the statistical analysis. The resulting threshold is a soft boundary between "small" and "large" applications for carbon capture, as regional differences in the distribution of emitters will not be captured with a UK-based data set.

8.2 Key modelling assumptions

8.2.1 Energy pricing

Table 25: Energy price projection for selected regions ($$_{2020}$/MWh)

Year	Netherlands			California			Texas			China		
	NG[61]	WE	IE	NG	WE	IE	NG	WE	IE	NG	WE	IE
2021	17.0	47.2	120.1	19.9	62.2	105.9	11.2	36.5	58.7	22.3	62.0	95.4
2022	17.2	48.3	121.1	19.8	64.9	108.7	10.6	34.1	56.4	23.1	64.8	98.2
2023	17.4	48.9	121.8	18.1	67.8	111.6	10.0	31.9	54.2	23.9	67.1	100.5
2024	17.6	49.4	122.2	17.6	61.2	105.0	9.7	32.2	54.4	24.6	69.0	102.5
2025	17.8	49.6	122.4	18.0	60.6	104.4	9.9	31.9	54.1	25.4	70.8	104.2
2026	19.1	51.3	124.2	18.4	60.7	104.5	10.1	32.0	54.2	26.2	70.5	103.9
2027	20.3	52.6	125.4	18.7	60.5	104.2	10.3	31.8	54.0	27.0	69.7	103.2
2028	21.6	54.1	126.9	19.3	60.2	104.0	10.6	31.7	53.9	27.8	69.5	103.0
2029	22.9	56.3	129.1	19.9	60.2	103.9	10.9	31.7	53.9	28.6	70.3	103.7
2030	24.1	57.9	130.7	20.0	59.7	103.4	11.0	31.4	53.6	29.3	70.4	103.9
2031	24.2	58.9	131.8	20.0	59.7	103.5	11.0	31.5	53.7	29.4	71.6	105.0
2032	24.3	60.0	132.8	20.3	59.3	103.1	11.1	31.2	53.5	29.4	72.7	106.1
2033	24.4	61.0	133.9	20.6	59.4	103.1	11.3	31.3	53.5	29.5	73.8	107.2
2034	24.5	62.1	134.9	20.8	59.2	103.0	11.4	31.2	53.4	29.5	74.9	108.3
2035	24.6	63.1	136.0	20.8	59.1	102.9	11.4	31.1	53.4	29.6	76.0	109.4
2036	24.7	64.2	137.1	20.8	58.5	102.3	11.4	30.8	53.0	29.7	77.2	110.6
2037	24.8	65.3	138.1	20.8	58.0	101.7	11.4	30.5	52.7	29.7	78.3	111.7
2038	24.9	66.4	139.2	20.9	57.5	101.3	11.5	30.3	52.5	29.8	79.4	112.8
2039	25.0	67.4	140.3	20.9	57.0	100.8	11.4	30.0	52.2	29.8	80.5	114.0
2040	25.1	68.5	141.4	20.8	56.6	100.3	11.4	29.8	52.0	29.9	81.7	115.1
2041	25.2	68.2	141.0	20.8	56.1	99.8	11.4	29.6	51.8	29.9	81.1	114.5
2042	25.2	67.8	140.6	20.7	55.7	99.5	11.4	29.4	51.6	30.0	80.5	113.9
2043	25.3	67.5	140.3	20.6	54.9	98.7	11.3	28.9	51.1	30.0	79.9	113.3
2044	25.4	67.1	139.9	20.6	54.4	98.2	11.3	28.7	50.9	30.1	79.3	112.7
2045	25.5	66.7	139.6	20.7	54.0	97.8	11.3	28.5	50.7	30.1	78.7	112.2
2046	25.6	66.1	138.9	20.7	53.5	97.2	11.3	28.2	50.4	30.2	77.8	111.2
2047	25.7	65.4	138.2	20.8	53.2	97.0	11.4	28.1	50.3	30.2	76.8	110.3
2048	25.8	64.7	137.5	21.0	52.9	96.6	11.5	27.9	50.1	30.3	75.9	109.3
2049	25.9	64.0	136.9	21.3	52.3	96.0	11.7	27.6	49.8	30.3	74.9	108.4
2050	26.0	63.3	136.2	21.5	51.7	95.4	11.8	27.3	49.5	30.4	74.0	107.4

[61] NG: natural gas; WE: wholesale electricity; IE: industrial electricity.

8.2.2 Carbon pricing

Table 26: Carbon price projection for selected regions ($\$_{2020}/tCO_2$)

Year	Netherlands	California	Texas	China
2021	69.83	19.36	0.00	6.83
2022	69.83	22.00	0.00	9.40
2023	69.83	25.00	0.00	11.98
2024	69.83	28.40	0.00	14.55
2025	76.56	32.27	0.00	17.13
2026	86.45	36.67	0.00	19.70
2027	96.04	41.67	0.00	22.28
2028	105.32	47.35	0.00	24.85
2029	114.31	53.80	0.00	27.43
2030	123.00	61.16	0.00	30.00
2031	123.00	66.97	0.00	31.50
2032	123.00	72.79	0.00	33.00
2033	123.00	78.61	0.00	34.50
2034	123.00	84.42	0.00	36.00
2035	123.00	90.24	0.00	37.50
2036	123.00	94.55	0.00	39.00
2037	123.00	98.85	0.00	40.50
2038	123.00	103.16	0.00	42.00
2039	123.00	107.47	0.00	43.50
2040	123.00	111.77	0.00	45.00
2041	123.00	115.83	0.00	46.00
2042	123.00	119.89	0.00	47.00
2043	124.83	123.94	0.00	48.00
2044	134.43	128.00	0.00	49.00
2045	144.03	132.05	0.00	50.00
2046	151.23	133.83	0.00	51.00
2047	158.43	135.61	0.00	52.00
2048	165.63	137.39	0.00	53.00
2049	172.83	139.17	0.00	54.00
2050	180.04	140.94	0.00	55.00

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