THE ROLE OF CARBON CAPTURE AND STORAGE (CCS) TECHNOLOGIES IN A NET-ZERO CARBON FUTURE

EDITED BY: Mai Bui, Graeme Douglas Puxty, Matteo Gazzani, Salman Masoudi Soltani and Carlos Pozo

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THE ROLE OF CARBON CAPTURE AND STORAGE (CCS) TECHNOLOGIES IN A NET-ZERO CARBON FUTURE

Topic Editors:
Mai Bui, Imperial College London, United Kingdom
Graeme Douglas Puxty, Energy, Commonwealth Scientific and Industrial Research Organisation (CSIRO), Australia
Matteo Gazzani, Utrecht University, Netherlands
Salman Masoudi Soltani, Brunel University London, United Kingdom
Carlos Pozo, Universitat Politecnica de Catalunya, Spain

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EDITORIAL
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Editorial: The Role of Carbon Capture and Storage Technologies in a Net-Zero Carbon Future

Mai Bui[1,2]*, *Matteo Gazzani*[3], *Carlos Pozo*[4], *Graeme Douglas Puxty*[5] and *Salman Masoudi Soltani*[6]

[1]Centre for Environmental Policy, Imperial College London, London, United Kingdom, [2]Centre for Process Systems Engineering, Imperial College London, London, United Kingdom, [3]Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, Netherlands, [4]Department of Chemical Engineering, Universitat Politècnica de Catalunya, Barcelona, Spain, [5]CSIRO Energy, Newcastle, NSW, Australia, [6]Department of Chemical Engineering, Brunel University London, Uxbridge, United Kingdom

Keywords: CCS, net zero emissions, CO_2 removal, BECCS, direct air capture, hydrogen, industrial decarbonisation

Editorial on the Research Topic

The Role of Carbon Capture and Storage Technologies in a Net-Zero Carbon Future

Carbon capture and storage (CCS) technologies are recognized as having an important role in providing a cost-effective approach to limit global warming to 1.5°C (IPCC 2014; IPCC, 2018). The transition towards net-zero CO_2 emissions will present technical, economic, commercial and policy challenges for the deployment of CCS and CO_2 removal technologies. The opportunities for deployment will be diverse, and will significantly depend on the specific conditions found in the different regions of the world. Factors like national policies, availability of local resources, infrastructure and economy features, breakdown of GHG emissions across sectors, and societal background and wealth will all interplay to create conditions that are either favorable or disadvantageous to the deployment of CCS. This special issue is a collection of articles that explore the role of CCS and CO_2 removal technologies in delivering reductions to CO_2 emissions for a net-zero carbon future. The collection of publications includes two reviews and six original research articles, which are summarized below.

Johnsson et al. maps the potential costs associated with integrating CCS into all industrial manufacturing plants in Sweden, illustrating the marginal abatement cost curve (MACC). This helps quantify the level of decarbonisation required and identify the types of CO_2 point sources, e.g., fossil fuel CO_2, or biogenic CO_2. The study evaluated the CO_2 capture costs of 28 plants in Sweden, including a petrochemical site, refineries, iron and steel plants, cement plants and pulp and paper mills. These plants generate >500 kt CO_2 of the annual emissions, which is >50% of Sweden's total CO_2 emissions from all sectors. The marginal abatement cost curve showed capture costs ranging between 40 and 110 €/t CO_2, depending on the emission source, and includes the cost of transport and storage (adds 25 to 40 €/t CO_2). Based on this type of analysis, a national strategy towards net-zero across the industrial sector could be developed, identifying the low-cost CO_2 capture options and opportunities for cost reduction.

Hydrogen and electrification are possible strategies for the decarbonisation of industrial clusters. Herraiz et al. proposes a system that uses steam methane reforming (SMR) for hydrogen production and power generation with CCS. An integrated system with SMR and power plant with CCS was found to produce 696,400 Nm^3/h of H_2 with a net power output of 651 MWe at a net thermal efficiency of 38.9 $\%_{LHV}$. The authors also present new insights for the design

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Uwe Schroder, Technische Universitat Braunschweig, Germany

***Correspondence:**
Mai Bui
m.bui@imperial.ac.uk

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and operation of reformers integrated with gas turbines and CO_2 capture, demonstrating methods to improve efficiency.

There are also opportunities to deploy new technologies in the power sector. Wevers et al. evaluates the potential of Power-to-Fuel-to-Power systems in delivering net-zero GHG emissions in energy systems, also considering the life cycle assessment (LCA) of environmental impacts. For comparison, another system generating electricity from natural gas combustion with 100% carbon capture and storage is also evaluated. Of the different Power-to-Fuel-to-Power systems, the hydrogen storage system had the lowest environmental impact in all categories. This study highlights the importance of LCA studies in identifying any negative environmental impacts associated with the deployment of new technologies.

Addressing the issue of high costs for technologies that remove CO_2 from air is a key challenge. The technoeconomic study by Kiani et al. identified key areas of possible performance improvement with conventional absorption-based direct air capture (DAC) using monoethanolamine (MEA). The energy consumption of MEA-based DAC was found to be a function of key process parameters, including air humidity, CO_2 capture rate, CO_2 loading of the lean and rich amine and reboiler temperature. The base case MEA scenario resulted in a reboiler duty of 10.7 GJ/ tCO_2 and an electrical energy requirement of 1.4 MWh/tCO_2, corresponding to a capture cost of \$1,691/tCO_2. The overall cost range of the DAC process was between \$273–1,227 per ton of CO_2, varying with different economic parameters. The study found that significant cost reductions could be achieved with the use of low-cost materials, innovative absorption contactor, which operates at lower liquid-to-gas ratios, and an absorbent with low volatility to avoid a water wash.

In the case of bioenergy with CCS (BECCS), the cost of transporting biomass can represent a significant proportion of the final biomass price, and there will be costs associated with CO_2 transport. Stolaroff et al. assessed the transport costs associated with BECCS projects using data for the United States. The cost-optimal combination of transport for each scenario was a function of the transport capacity and distance. Biomass transport by rail is the most competitive option for systems capturing and storing most of the biogenic CO_2, e.g., gasification to hydrogen or combustion for electricity generation. For large projects storing >1 Mt/yr CO_2 or transporting CO_2 > 1,000 km, the lowest cost option for CO_2 transport is pipeline. In contrast, CO_2 transport by rail is more cost competitive for smaller BECCS projects. In cases where developers have flexibility to choose the BECCS project type and transport modes, the transport costs were between \$20–40/ tCO_2 stored for projects with distances of hundreds of kilometers from the biomass source to the storage site.

Scenario-based assessments are particularly useful in identifying deployment hurdles and opportunities at a systems scale. The systematic review of 66 German energy and decarbonisation scenarios by Hahn et al. identifies "blind spots" in regards to scenario assumptions around BECCS technology options and applications. The review reveals that future scenario analyses need to incorporate other considerations, including a framework for land use change and emissions accounting (only considered in ~10% of scenarios), as well as the impact of public acceptance on technology deployment.

Another key consideration highlighted by Fuss and Johnsson is that scenarios need to consider the technology deployment rate as well as ensure that the ramp-up in deployment is achievable. The conditions for BECCS in Sweden are particularly favorable due to the existing large point sources of biogenic CO_2 emissions in the country. Despite the favorable conditions, the current deployment rate of BECCS is limited. To achieve Sweden's net-zero target by 2045, two ramp-up scenarios for BECCS were proposed. The study reveals that immediate introduction of political and economic incentives would likely be required to significantly accelerate deployment to the levels required for the target.

A review and analysis of the status and possibilities of CCS deployment in the Netherlands by Akerboom et al. indicates there are no significant technical challenges. Historically, CCS deployment has mainly been hindered in the Netherlands by the lack of a compelling socio-technical narrative. Owing to the shift in focus from power to industry, CCS is now deemed vital in the transition to net-zero, offering the means to rapidly reduce CO_2 emissions significantly. The narrative around CCS is more favourable. The prospects of CCS have also appeared to improve since the introduction of new financial mechanisms, as well as increased government support and social engagement. Fit-for-purpose legal frameworks and policy instruments will likely have an important role.

AUTHOR CONTRIBUTIONS

MB was the primary author of the Editorial. MG, CP, GP, and SS provided feedback and contributions to the paper.

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ORIGINAL RESEARCH
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Techno-Economic Assessment for CO_2 Capture From Air Using a Conventional Liquid-Based Absorption Process

*Ali Kiani, Kaiqi Jiang and Paul Feron**

CSIRO Energy, Mayfield West, NSW, Australia

In this study, the process of carbon dioxide (CO_2) capture directly from ambient air in a conventional monoethanolamine (MEA) absorption process was simulated and optimized using a rate-based model in Aspen Plus. The process aimed to capture a specific amount (148.25 Nm^3/h) of CO_2 from the air, which was determined by a potential application aiming to produce synthetic methane from the output of a 2.7 MW electrolyser (593 Nm^3/h H_2). We investigated the technical performance of the process by conducting a sensitivity analysis around different parameters such as air humidity, capture rate defined as a ratio of moles of CO_2 captured during the process to the total mole of CO_2 in the feed stream, CO_2 loading of lean and rich absorption liquids and reboiler temperature, and evaluated the energy consumption and overall cost in this system. In order to meet the design requirement for standard packed columns, the rich absorption liquid was circulated to the top of the absorber. A capture rate of 50% was selected in this process as a baseline. At higher capture rates, the required energy per ton of captured CO_2 increases due to a higher steam stripping rate, required in the desorber, and at lower capture rates, the size of equipment, in particular, absorber and blowers increases due to the need for processing a significantly larger volume of air at the given CO_2 production volume. At the base case scenario, a reboiler duty of 10.7 GJ/tCO_2 and an electrical energy requirement of 1.4 MWh/tCO_2 were obtained. The absorber diameter and height obtained were 10.4 and 4.4 m, respectively. The desorber is found to be relatively small at 0.54 m in diameter and 3.0 m in height. A wash water section installed at top of the absorber decreased the MEA loss to 0.28 kg/ton CO_2. However, this increased capital cost by around 60% resulting in CO_2 capture costs of $1,691 per ton CO_2 for the MEA base scenario. Based on the techno-economic analysis, assuming a non-volatile absorbent rather than MEA thereby avoiding a wash water section, and using an absorption column built from cheaper materials, the estimated cost per ton of CO_2 produced was reduced to $676/$tCO_2$. The overall cost range was between $273 and $1,227 per ton of CO_2 depending on different economic parameters such as electricity ($20–$200/MWh) and heat price ($2–$20/GJ), plant life (15–25 years) and capital expenditure (±30%). In order to reduce the cost further, the use of innovative cheap gas-liquid contactors that operate at lower liquid to gas ratios is crucial.

Keywords: CO_2 capture, techno—economical assessment, chemical absorbents, amine, air capture

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Edited by:
Mai Bui,
Imperial College London,
United Kingdom

Reviewed by:
Joan Ramón Morante,
Institut de Recerca de l'Energia de Catalunya, Spain
Stefano Stendardo,
Italian National Agency for New Technologies, Energy and Sustainable Economic Development (ENEA), Italy

****Correspondence:***
Paul Feron
paul.feron@csiro.au

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INTRODUCTION

Ongoing use of fossil fuel over the past one and half century led to an increase in the concentration of CO_2 in atmosphere from around 280 ppm to just above 400 ppm (Lindsey, 2019). Concerns about the effect of this increase on the global climate resulted in increasing efforts for the development of technologies that enable to remove CO_2 directly from atmosphere referred to as Negative Emissions Technologies (McGlashan et al., 2012; McLaren, 2012; Pritchard et al., 2015). Recent studies indicate that in order to prevent the increase of global temperature to about 2°C above the pre-industrial era by the end of this century, the large scale deployment of negative emission technologies is probably required (Gasser et al., 2015).

Among all proposed negative emission technologies (McLaren, 2012; Gasser et al., 2015), the direct capture of CO_2 from air (DAC) by physical or chemical processes attracted more attention due to the advantages that this method offers. For instance, DAC technology requires a relatively small area of land and can be located close to the storage/utilization sites or even can be deployed in remote areas where the land is unusable, or on the roofs of buildings in populated cities. It can also provide a larger removal capacity compared to other methods of CO_2 removal from atmosphere (Baciocchi et al., 2006). Moreover, DAC was claimed to provide a means for a permanent decrease of CO_2 concentration in atmosphere (in fact it can capture 100% of CO_2 emission to the atmosphere), for capturing dispersed fugitive emissions, and for direct use in different industries such as beverage, greenhouse, and synthetic fuels production industries (Lackner et al., 1999; Keith, 2009; Lackner, 2009; Krekel et al., 2018).

Several technologies are proposed and investigated in the literature for the direct capture of CO_2 from ambient air. Carbon Engineering, Climeworks and Global Thermostat are the three major companies that developed technologies for the large scale capturing of CO_2 from air. Carbon Engineering uses a potassium hydroxide solution to capture CO_2 and the energy intensive calcination process to regenerate the solvent. On the other hand, the other two companies, Climeworks and Global Thermostat use solid sorbents to capture CO_2. They use high temperature and low pressure to regenerate the sorbent. A summary of these studies is shown in **Table 1**. Based on these studies, DAC is currently considered as an energy-intensive and costly approach for removing CO_2 from the atmosphere. However, researchers believe that the high cost and energy consumption in such systems are mostly due to the immaturity of the technology, and hence DAC may be eventually considered as a viable option for removing CO_2 from the atmosphere (Field and Mach, 2017; Senftle and Carter, 2017). Further research is under way on different aspects of the process such as the chemistry and stability of liquid and solid sorbents, their effective contact with gas and process modifications in order to reduce the energy requirements and cost of such systems.

The use of aqueous alkaline sorbents such as NaOH, $Ca(OH)_2$, and KOH, based on the concepts of the conventional MEA absorption process, for the DAC application, was claimed to provide a simpler contact between air and sorbents. It was also anticipated that the system can operate continuously with a very long contactor's lifetime as the absorbing liquid in such systems is not subject to degradation reactions. The high cost for the regeneration of the aqueous solutions and water loss are the main disadvantages of such liquid-based absorption systems (Lackner, 2009; Wang et al., 2011; Keith et al., 2018).

While testing CO_2 capture systems at large scale is expensive, process simulation programs such as Aspen Plus have been widely used to evaluate the process configurations and identify the optimum operating conditions. There are a number of studies that used Aspen Plus to model CO_2 capture from flue gases in MEA-based absorption processes (Desideri and Paolucci, 1999; Freguia and Rochelle, 2003; Alie et al., 2005; Svendsen and Hoff, 2005; Øi, 2007). However to the best of our knowledge, no such simulation study has been conducted for CO_2 capture from air. Such a study is believed to be important as it provides a baseline for the technical and economic performance of DAC technologies that use chemical absorption processes.

In this work, using a rate-based model in Aspen Plus, we conducted a comprehensive analysis on the performance of a conventional MEA-based absorption process for capturing CO_2 from air, with particular focus on reducing the thermal and electrical energy consumption and, ultimately, the overall cost. The process performance is evaluated against the various parameters such as air humidity, the CO_2 loadings of lean and rich solutions, capture rate and reboiler temperature. As a result, a benchmark condition for DAC technologies that use a chemical absorption process is determined and a parametric techno-economic assessment is conducted for this baseline case study. Further analysis of the study results has resulted in the identification of areas for efficiency improvement and cost reduction.

METHODOLOGY

Process Description

An MEA-based air capture process was designed to capture CO_2 from air. **Figure 1** shows the representation of the air capture process using a standard stripping process (a) and a cold rich-split process (b).

A conventional packed column was utilized for CO_2 absorption using a 30 wt% MEA solution, which is typically used for CO_2 capture from flue gas. It is important to note that the CO_2 concentration in air is ∼300 times lower than that in the flue gas from coal-fired power station. Hence the absorption liquid flow could be much lower than that in a flue gas capture system. However, this would give rise to an extremely low liquid to gas ratio (L/G) that could not be achieved in a traditional packed column. In terms of operability, the process design used a liquid recirculation process in which most of the rich CO_2 absorption liquid exiting absorber is pumped to the top of absorber in order to achieve a standard L/G of about 2.5 in the absorber, at a 70% flooding ratio. A small portion of the rich absorption liquid is sent to the desorber for CO_2 removal. The regenerated lean absorption liquid from the desorber was cooled and mixed with the absorption liquid exiting the absorber, and fed back to the

TABLE 1 | Major technologies on direct air capture.

Investigator	Capturing method	Sorbent	Regeneration	Application	Maximum capacity (ton/year)	References
Carbon Engineering Company	Absorption	KOH solution	Calcination process (High temperature)	Synthetic fuels	1,000,000****	Keith et al., 2018
Climeworks Company*	Adsorption	amine based porous sorbents	High temperature	Greenhouse, Synthetic fuels	900	Climeworks press release, 2017; Marshall, 2017
Global Thermostat Company	Adsorption	amine based monoliths	High temperature and low pressure (vacuum)	Beverage and food	4,000****	Li et al., 2016; Chichilniski, 2018
Arizona State University and Columbia University***	Adsorption	Anionic exchange resin	High moisture	–	Not declared	Lackner, 2009; Wang et al., 2011
Others**: VTT, the Oak Ridge Laboratory, The US Naval research lab, X and PARC, European Space Agency, infinitree	Adsorption/ Absorption	Amine-functionized polymer/Aqueous amino acid solutions/ Ion exchange	High temperature/low pressure/precipitation/	Fuels/longer space mission/Greenhouse	<1	Sandalow et al., 2018

**First company that commercially captured CO_2 from air, producing around 900 tCO2/year for a greenhouse.*
***Produced CO_2 at very small scale.*
****Produced CO_2 at low concentration (5%).*
*****They claimed this as their predicted production capacity.*

top of absorber for continuous CO_2 absorption. The desorption process can be modified using a cold rich-split configuration, i.e., sending a small portion of cold rich absorption liquid to the top of desorber, as shown in **Figure 1B**, to reduce the reboiler duty.

Process Simulation

A rigorous, rate-based MEA model developed in Aspen Plus was used to simulate the air capture process. The MEA model has been well-validated in previous work at CSIRO (Li et al., 2016; Jiang et al., 2018) against the pilot plant experimental results and laboratory data and is expected to achieve reliable simulation results for the air capture process. Please refer to the **Table 1** in the paper published by Li et al. (2016) for further detail about the MEA model.

A series of simulation activities were undertaken to examine the effect of various technical variables on the reboiler duty and equipment size to determine the optimized conditions for a standard MEA-based air capture process. In this optimization, the aim is to minimize the reboiler duty at any given conditions, for example different capture rates etc. The generic simulation conditions used for the CO_2 absorption and desorption are provided in **Table 2**. Technical parameters, i.e., CO_2 capture rate, rich CO_2 loading, lean CO_2 loading and air relative humidity were varied in the simulations, within the ranges shown in **Table 2**. The process was simulated based on the production of 148.25 Nm^3/h of CO2 from the air (0.291 ton/h at standard conditions). This production size determined by a potential application aiming to produce synthetic methane from the output of a 2.7 MW electrolyser that has around 78% efficiency (593 Nm^3/h H2).

Once the optimized conditions were determined using the standard absorbent regeneration process, the technical performance was further optimized using the rich-split configuration and the addition of a wash water column (**Figure 1C**) to the absorber, providing a technical basis for the economic evaluation of the MEA-based air capture process.

Economic Evaluation

With the determination of technical parameters and equipment size of the air capture process, the Aspen Capital Cost Estimator (ACCE) was utilized to estimate the direct costs for the equipment, materials and labor for construction of the air capture plant. The other costings associated with the supportive materials and labor, facilities, engineering, contractors and contingencies for plant construction were estimated based on the direct costs using multiplicative factors. These multiplicative factors were derived from a 2007 report from the Department of Energy, USA (DOE/NETL, 2007) for estimating the capital costs of an early post combustion carbon capture (PCC) plant. The assumptions for capital costs estimation and input data for the air capture process are shown in **Table S1**. For the costings of plant operation and maintenance, the annual maintenance cost was assumed to be 3% of total capital costs, and 30% of maintenance cost was assumed to be the labor cost (Socolow et al., 2011). The other plant and financial assumptions and economic information for the base case, such as plant capacity, plant life, discount rate, energy price etc. are also provided in **Table S1**.

RESULTS AND DISCUSSION

Technical Performance

In this section, the effects of various parameters on the air capture process are reported. The heat of regeneration and the size of absorber are mainly discussed as they are often the two major costs in CO_2 capture process. It should be mentioned again that this process aims to capture a specific amount of CO_2 from air (around 0.291 t/h).

Capture Rate

Here it is assumed that a constant amount of CO_2 was produced from ambient air using the MEA-based absorption process as the capture rate of the process varied from 20 to 90%. The simulation results revealed that at a capture rate of 90% the reboiler duty was 21.9 GJ/tCO_2, almost double the one required in a process with

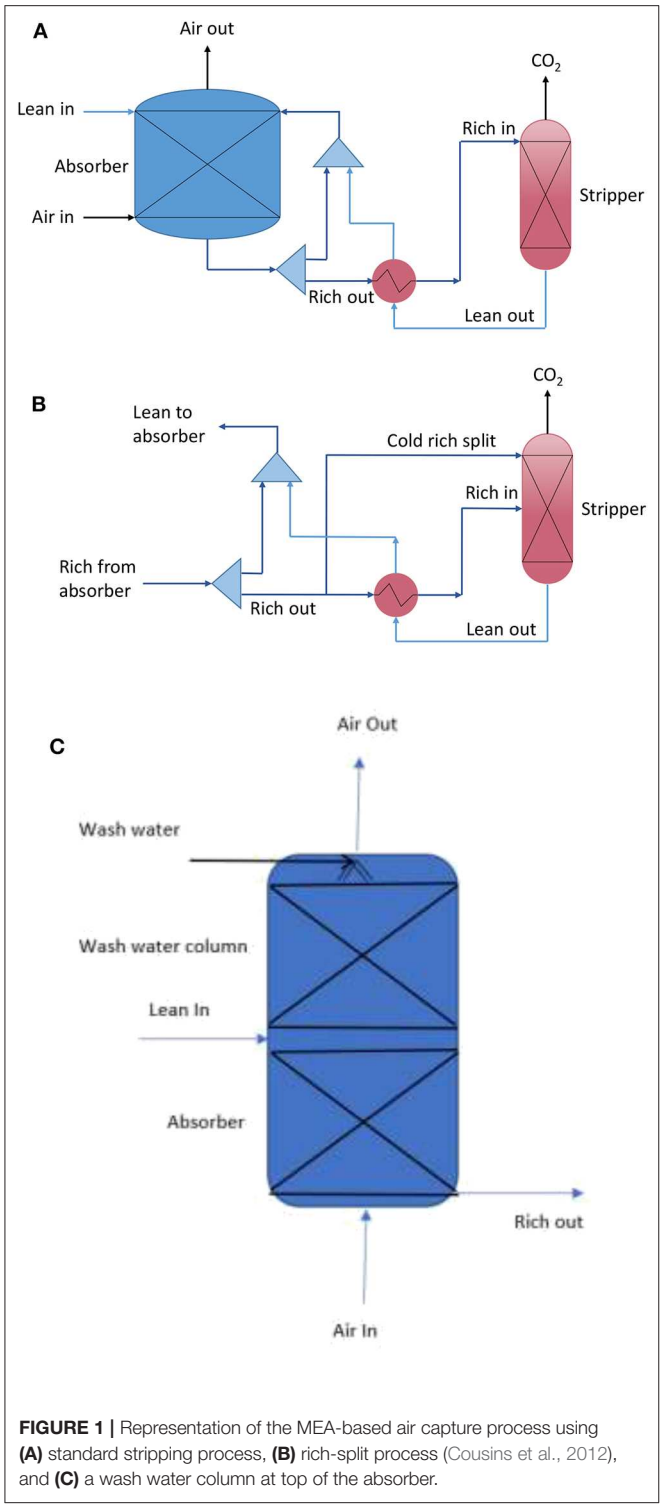

FIGURE 1 | Representation of the MEA-based air capture process using **(A)** standard stripping process, **(B)** rich-split process (Cousins et al., 2012), and **(C)** a wash water column at top of the absorber.

a capture rate of 20% (**Figure 2A**). This is due to the fact that at lower capture rates, the rich loading is higher, and this results in a lower relative vaporization heat required in the desorber. The decrease in reboiler duty would reduce the operating cost of the air capture process.

TABLE 2 | Conditions for the MEA-based CO_2 capture process simulation.

Parameters	Value
Generic conditions	
CO_2 concentration in inlet air, ppm	400
Inlet air temperature, °C	25
CO_2 capture rate, ton/h	0.291
MEA concentration, wt%	30
L/G for absorber with circulation, ton/ton	2.54
Packing materials in absorber and desorber	Mellapak 250X
Flooding capacity of absorber/desorber (%)	70/65
Desorber pressure (bar)	2
Temperature approach of cross heat exchanger, K	10
Variable conditions	
Capture rate, %	20, 35, 50, 70, 90
Rich loading, mol/mol	0.27, 0.30, 0.33, 0.36
Lean loading, mol/mol	0.15, 0.20, 0.25
Air relative humidity, %	30, 50, 70, 90

Figure 2B shows that the absorption column height required for capturing the specific amount of CO_2 in a system with 90% capture rate was almost 6 times greater than that required in a system with 20% capture rate. This is due to the longer contact time between liquid and air required in the system with 90% capture rate. It should be considered that in order to produce a specific amount of CO_2 with an air capture system at low capture rate, a significantly larger volume of air needs to be processed. This results in a larger diameter absorption column (**Figure 2**). This suggests that considering a capture rate of around 50% may be more feasible in terms of cost effectiveness of the air capture process. It should be noted that the optimum capture rate can vary with the economic parameters such as electricity and heat prices. For example, if electricity and heat are available at low cost, the optimum capture rate can be >50%. A summary of operating conditions and results at different capture rates are indicated in **Table S2**.

An air capture system operating at a low capture rate can also result in an extra number of energy and cost components, such as much higher MEA loss, a more significant circulation rate of rich absorption liquid to the absorber, and a significantly high energy requirement for air movement through the absorption column.

CO_2 Loading

The effect of the CO_2 loading of lean and rich absorption liquids on the reboiler duty and the size of the absorber were examined at a 50% capture rate. **Figure 3A** shows that the reboiler duty decreased by about 50% with increasing the lean loading from 0.15 to 0.25. With increasing lean loading, the loading in the recirculation of the absorber increased as well, leading to a lower regeneration duty. Higher rich loadings led to a lower ratio for water vapor to CO_2 in the desorber, hence it reduces the heat requirement for vaporization in the desorber. However, as the lean loading and consequently the liquid loading in the absorber recirculation increased, the lower mass transfer driving

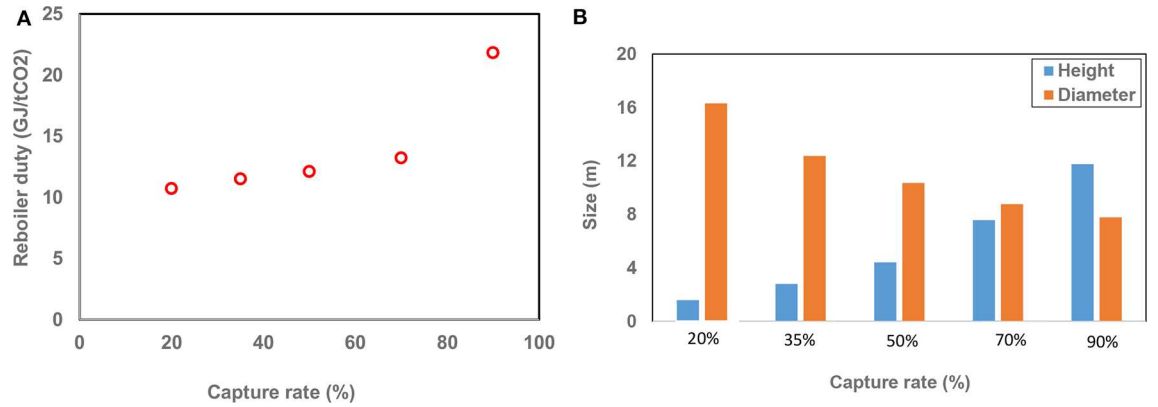

FIGURE 2 | The variation of **(A)** reboiler duty and **(B)** the height and diameter of the absorber with capture rate.

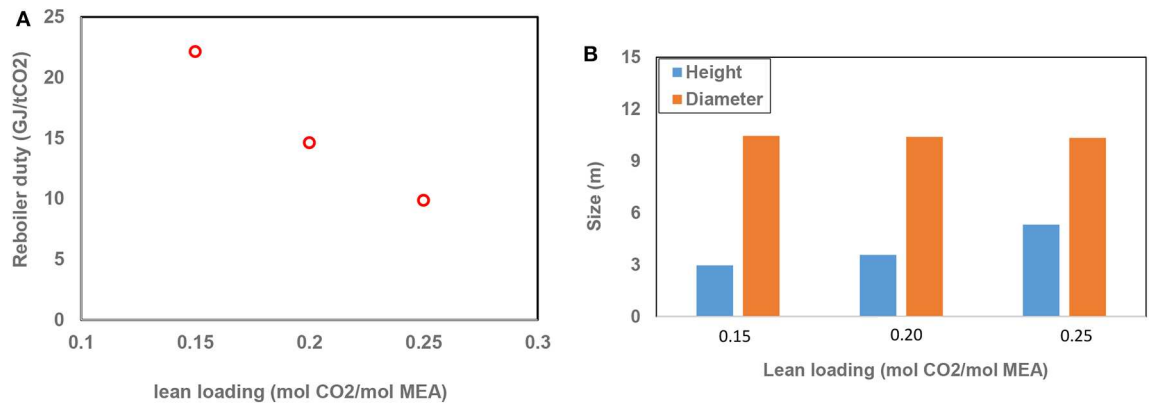

FIGURE 3 | (A) Reboiler duty and **(B)** absorber size variations with lean loading.

force led to a taller absorption column. **Figure 3B** also shows that the column diameter which is mainly dependent on the hydrodynamics of the system expectedly remained unchanged with lean loading. Again, the loss of MEA was significantly higher at higher loadings due to the large volume of air processed. **Table S3** lists the simulation's parameter and results for this case study. It is noted that the air humidity of 90% considered in this case changed the results slightly compared to the case when air humidity is 100%.

The effects of CO_2 loading of rich absorption liquid on the performance of the process were also investigated. In this set of conditions, a lean loading of 0.2 and a humidity of 100% were used. As evident in **Figure 4**, the heat of regeneration in the reboiler decreased from 24.1 GJ/tCO_2 to about 12.1 GJ/t CO_2 with increasing the rich loading from 0.26 to 0.35 mol CO_2/mol MEA, which is due to the lower relative vaporization in the desorber at higher rich loadings. As expected, the height of the absorber increased with increasing rich loading.

Air Humidity

The effect of humidity of inlet air on the air capture process was also evaluated. This is important as the very large volumes of air that pass through the absorber may lead to high rates of water vaporization, depending on humidity of the inlet air. The results indicate that the reboiler duty decreased from 14.4 GJ/tCO_2 to around 9.9 GJ/tCO_2 when the relative humidity of air increased from 30 to 90% (**Figure 5**). In the low humidity cases, a massive amount of water was evaporated, which resulted in an absorption liquid containing a higher concentration of MEA. At the fixed pressure in the desorber, the reboiler temperature and the required heat of regeneration consequently increased. **Figure 5** also shows that the water loss was around 13 t/tCO_2 when the air relative humidity was 30% while it decreased to 2.5 t/tCO_2 when a 90% humid air was used. This suggests that preventing water losses would be beneficial when processing relatively dry air. This could be done by applying appropriate water separation system to recover the lost water. Otherwise, there would be a substantial water supplement for the air capture system, in turn increasing the costs of the air capture process.

The humidity of the inlet air had no effect on the height and diameter of the absorber.

Reboiler Temperature

Next, the effect of reboiler temperature on the performance of the air capture process was examined. A lean loading of 0.2, a rich loading of 0.35 and a capture rate of 50% were considered for this

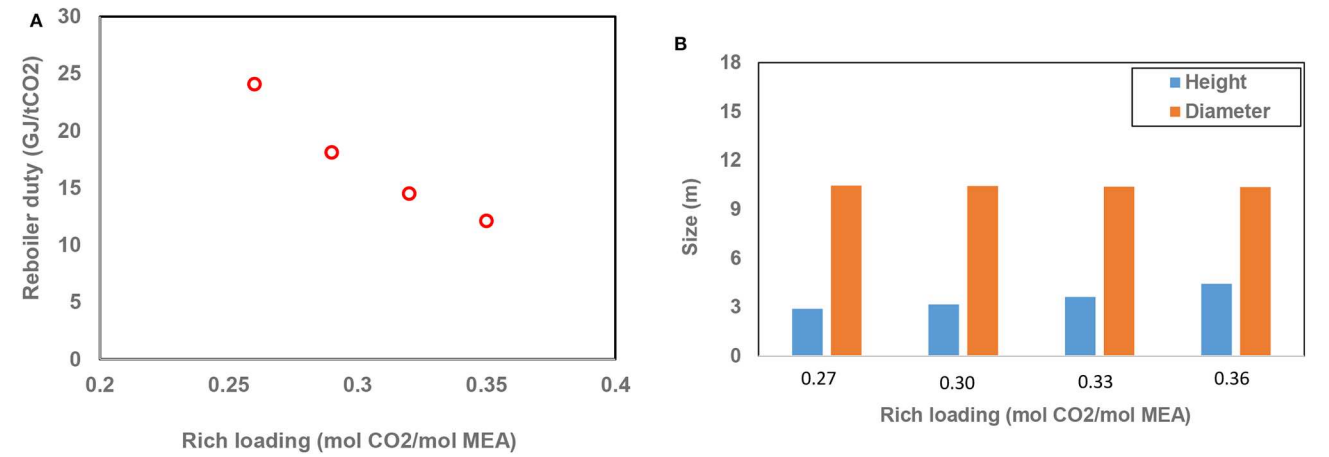

FIGURE 4 | (A) Reboiler duty and **(B)** absorber size variations with CO_2 loading of rich absorption liquid.

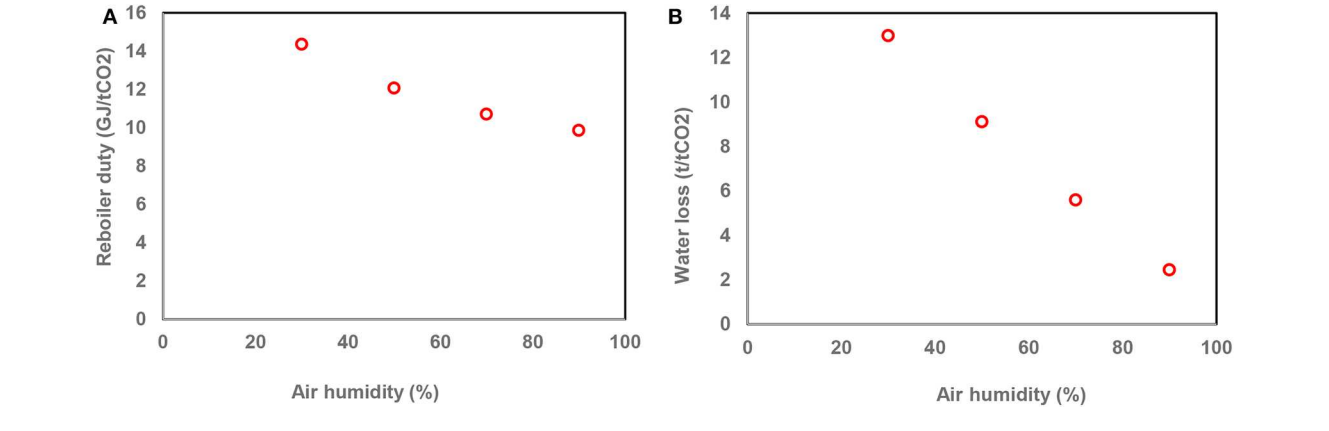

FIGURE 5 | (A) Reboiler duty and **(B)** water loss as a function of the inlet air relative humidity.

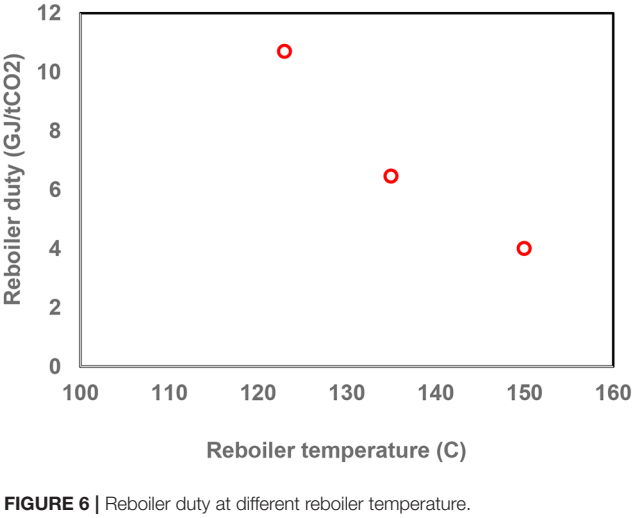

FIGURE 6 | Reboiler duty at different reboiler temperature.

case. **Figure 6** shows that the reboiler duty decreased significantly with increasing the reboiler temperature. By increasing the reboiler temperature from 123 to 150°C, the reboiler duty decreased by more than 50%, to around 4.0 GJ/tCO_2. The operating conditions and results are given in **Table S4**. The results indicate the importance of alternative absorption liquids to have a higher resistance to thermal degradation. MEA does not lend itself for regenerator temperatures much higher than higher than 120°C. However, there are other amines and amine formulations such as piperazine that could be used at temperature up to 160°C (Rochelle, 2016).

Benchmark Conditions for the Capture Process

According to the results obtained from the sensitivity analysis shown above, a benchmark condition was selected for the capture of CO_2 from air using the MEA absorption process. This point was based on a capture efficiency of 50%, a lean loading and a rich loading of 0.2 and 0.35, respectively, and a reboiler temperature of 123°C. The rich split configuration was used in this case study due to its superior energy performance. A detailed analysis was conducted for this base case scenario, which included determination of thermal and electrical energy requirements in this system. The total electricity consumption for air blowers and liquid pumps was calculated to be 1.452 MWh/tCO_2, and the reboiler duty was calculated to be 10.7 GJ/tCO_2. The absorber

TABLE 3 | The operating conditions and process simulation results for a base case scenario in the air capture process.

Operating conditions	
Inlet air temperature (C)	25
Air relative humidity (%)	100
CO_2 production (t/h)	0.291
CO_2 concentration in inlet air (ppm)	400
CO_2 capture efficiency (%)	50
Flow rate of air (t/h)	943
MEA concentration (%)	30
Flooding capacity of absorber/desorber (%)	70/65
L/G in absorber	2.54
Type of packing in the absorber and desorber	M250X
CO_2 rich loading	0.35
CO_2 lean loading	0.2
Desorber pressure (bar)	2
Temperature approach on cold side (K)	10
Simulation results	
Absorption liquid flow to desorber (t/h)	9.113
Absorber recirculation liquid flow (t/h)	2396.5
Specific liquid flow to desorber (t/tCO_2)	31.3
Specific absorber recirculation flow (t/tCO_2)	8247.3
Condenser temperature (°C)	31.2
Reboiler temperature (°C)	123.1
Reboiler duty (GJ/tCO_2)	10.70
Total electricity (MWh/tCO_2)	1.452
MEA evaporation in absorber (kg/tCO_2)	53.4
Wash water flow (kg/s)	612
MEA loss after water wash (kg/tCO_2)	0.28
Equipment dimensions	
Absorber packing diameter (m)	10.36
Absorber packing height (m)	4.43
Absorber volume (m^3)	373.2
Absorber pressure drop (kPa)	0.73
Washing column pressure drop (kPa)	0.26
Washing column packing diameter (m)	10.36
Washing column packing height (m)	5
Cross heat exchanger surface area (m^2)	102.59
Desorber diameter (m)	0.544
Desorber packing height (m)	3
Desorber (m^3)	0.70
Electrical Energy Requirements	
Recirculation pump (MWh/tCO_2)	0.504
Washing pump work (MWh/tCO_2)	0.238
Blower work (MWh/tCO_2)	0.703
Pumps to/from desorber (MWh/tCO_2)	0.007
Total (MWh/tCO_2)	1.452

height and diameter were calculated to be 6.3 and 10.4 m, respectively. A wash water section, 10.4 m in diameter and 5 m high, was also added to decrease the evaporative loss of MEA to around 0.28 kg/tCO_2 (0.04 ppm in exhaust air) during the absorption process. The desorber dimensions are significantly smaller than the absorber dimensions which reflects the large difference in gas and liquid flow rates. The final simulation results for this base case scenario is indicated in **Table 3**. The break-down of required electrical energy in this process are also indicated in **Table 3**.

TABLE 4 | Economic performance of MEA-based air capture. All the costs are on a basis of 1st Qtr 2016 US$.

Major equipment and cost element	**Cost, Million US$**
Washing column	4.38
Absorber	4.22
Desorber	0.13
Blowers and fans	1.66
Heat exchangers	0.39
Pumps	0.30
Tanks	0.40
Other equipment	0.22
Total direct costs	11.70
Total indirect costs	2.27
Engineering	1.40
Contractor fees	0.42
Contingencies	3.49
Total plant costs	19.27
Spare parts	0.096
Total investment costs	19.37
Operating expenses	
Annual O&M costs	0.757
Annual heat costs	0.213
Annual electricity costs	0.286
Capture costs	**$/ton CO_2**
Capital	1,033
O&M	396
Heat	111
Electricity	150
Total	1,691

Economic Performance of the Base Air Capture Process

CO_2 Capture Cost—Standard Chemical Engineering Design

Using the Aspen Capital Cost Estimator with the base case design specified in **Table 3** and standard chemical engineering design specifications, the CO_2 capture cost was calculated to be \$1,691/ton CO_2 for the MEA-based air capture. It should be noted here that this estimation is based on particular capture amount of 0.291 tCO_2/h (∼2,300 tCO_2/year). Considering the economy of scale (Blok and Nieuwlaar, 2017), the cost per ton of CO_2 captured will be lower for larger scale systems. **Table 4** provides the specific costs of major equipment and total investment costs, the operating expenses and the break-down of CO_2-capture costs. **Figure 7A** provides the distribution of capture costs over capital, operating expenses and energy

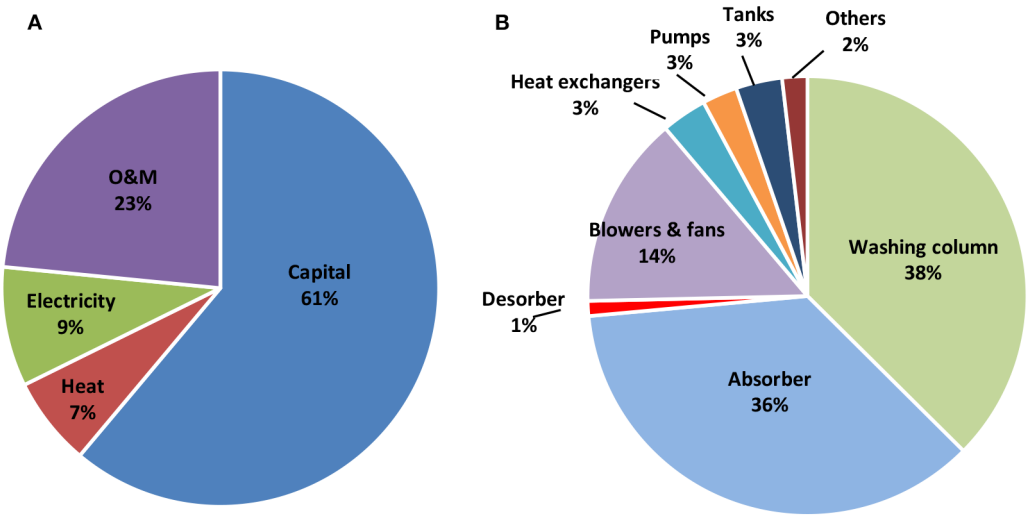

FIGURE 7 | (A) CO_2 capture cost distributions on capital, O&M, electricity and heat, and **(B)** capital cost distributions of major equipment in the MEA-based air capture.

expenses. The capital constitutes 61% of the CO_2 capture cost, followed by 23% for O&M, 9% for electricity consumption with heat consumption being the smallest contribution at 7%. The contribution of electricity and heat to the total cost can be significantly reduced if there would be cheaper sources of electricity and heat available for the process. The sensitivity analysis around different economic parameters including the heat and electricity price will be discussed in the next section.

The total capital costs of the MEA-based air capture process were estimated to be $19.37 million for our benchmark MEA-based air capture process. The washing column ($4.38 million) and absorber ($4.22 million) constituted the largest and the second largest capital item among the total capital investment and accounted for 74% of total capital costs, as shown in **Figure 7B**. Considering that a water cooling system could be difficult to implement on locations with shortage of water, air cooling was used in the present study for the cooling requirement. Due to the large amount of air requirement to meet the high cooling duty of stripper condenser and the large air flow through absorber for CO_2 absorption, the costs of blowers and fans accounted for 14% of total capital costs, being the third largest contribution.

By comparison, the annual costs of O&M and energy, i.e., electricity for blowers and pumps and heat for absorbent regeneration, are lower than the capital costs. The electricity costs ($0.286 million/year) were higher than the heating costs ($0.213 million/year) owing to the large electricity consumption for air transfer through the columns and solution pumping and the high circulation for CO_2-absorption and washing. It should be noted here that, in the base case, if less humid air than 100% was used, the added cost due to water evaporation in this process would be up to $4/t$CO_2$, which is still negligible in comparison with other cost components shown in **Table 4**.

For the base case, a plant life of 20 years, a discount rate of 8%, a capacity factor of 90%, heat price of $10/GJ and electricity price of $100/MWh were considered. A sensitivity analysis shows that with variation of equipment costs in the range of 30%, the CO_2 capture cost varied between $1,262 and $2,120/ton CO_2, a 34% decrease/increase with the 30% decrease/increase in capital costs. This again suggests that decreasing the process equipment costs would significantly reduce the cost of CO_2 capture from air. This can be achieved by three aspects: (1) enhancing mass transfer between absorbent and CO_2 through more efficient gas-liquid contacting in order to reduce the equipment size of CO_2 absorption, (2) absorbents that have lower evaporation of absorbent (water and amine) to the air in order to minimize the size of equipment for emission control, and (3) seeking cheaper materials for equipment manufacture in order to reduce the equipment costs. In the following section, these elements for reducing the cost of the air capture process will be explored qualitatively.

CO_2 Capture Cost—New Design

As described, the wash water section and absorber constitute 45% of total cost in the process, hence using an alternative absorption liquid with low vapor pressure and replacing the packings and absorber materials with cheaper materials can drastically reduce the total cost of the process.

– Use of alternative absorption liquid

Owing to the contact between the large volume of air and the small amount of liquid in the air capture process, MEA is evaporated during the absorption process. As discussed in section Benchmark Conditions for the Capture Process, this necessitates the use of a large wash water section after the CO_2 absorber, and hence creates an additional cost to the process. As shown in **Figure 7B**, 38% of capital cost is related to this wash water section, which in fact constitutes around 25% of total cost of the process.

Amino acid salts solutions have been proven to have a potential for absorbing CO_2 with an effectiveness that matches that of MEA (Aronu et al., 2010; Jockenhövel and Schneider, 2011; Ciftja et al., 2013; Guo et al., 2013; Wei et al., 2014; He et al., 2017). These salts do not impose any amine vapor. Based on the assumption that they show the same performance as MEA in the CO_2 capture process, if they are used in the air capture process, the need for the wash water section can be eliminated from the process. This will reduce the capital cost of the CO_2 capture process from \$1,033 to around \$640 per ton of CO_2. This will also decrease the electrical energy requirement from 1.452 MWh/tCO_2 to around 1.03 MWh/tCO_2, as the washing water pump is no longer required, and less energy will be required for blowing the air into the absorber. This will reduce the electricity cost from \$150 to around \$126 per ton of CO_2.

– Use of cheap plastic packings

Based on the techno-economic analysis in APS report (Socolow et al., 2011) and details by Carbon Engineering (Holmes and Keith, 2012; Keith et al., 2018), cost of packing materials can be up to one third of the total cost of major equipment. Using the cheap plastic packings as proposed by Carbon Engineering, the cost was reported to be 1/6 of standard stainless steel packings such as Sulzer Mellachevron 250X. Assuming the same cost for Mellapak 250X and Sulzer Mellachevron 250X, this reduces the cost of packings in this process from \$1,190,000 to around \$198,000. The absorber cost reduction is around 23% from \$372/ton of CO_2 to around \$285/ton of CO_2 (another \$87 reduction in capital cost to \$554 per ton of CO_2).

– Use of cheap materials in absorber structure

The cost of the absorber structure was reported to be around \$2,300 and \$3,700 per inlet area of absorbers (m^2) for cooling tower and contactors used in Carbon Engineering's process (Holmes and Keith, 2012), respectively, while based on the APS report (Socolow et al., 2011), the cost for a conventional absorption tower is around \$15,800 per inlet area of absorber (m^2). This shows that the cost of the absorber using a standard chemical engineering design specification is around 6 times more than the structure used in the cooling towers/Carbon Engineering systems. This means that if the absorption column used in this work is replaced by a cooling tower system, the cost of absorber structure will be reduced by 83% from \$30,32,800 to around \$505,460. This reduces the absorber cost by another 60% to \$62 per ton of CO_2 which is close to the number reported by Carbon Engineering. The total capital cost contribution of capturing CO_2 from air will be decreased to \$317 per ton of CO_2. It is assumed that the cheaper absorber equipment materials used are resistant toward to the amino-acid based absorption liquids.

The details of techno economic result based on the new design are given in **Table 5**. The final cost of capturing CO_2 from air is \$676/ton of CO_2, which is close to the cost reported by Climeworks (Climeworks press release, 2017; Marshall, 2017) (\$600/ton of CO_2) and in the APS report (Socolow et al., 2011) (\$610/ton of CO_2).

Figure 8 shows different cost components of the new liquid-based absorption process that was designed based on new absorption liquids, packings and absorber materials. In this new design, capital investment is still the main contributor to the total cost of the process. Among the major equipment, the cost of blowers and fans for moving the massive amount of air has now become the major part in the capital investment.

TABLE 5 | Economic performance of an improved amine-based air capture process.

Major equipment and cost element	**Cost, Million US$**
Absorber	0.70
Desorber	0.13
Blowers and fans	1.66
Heat exchangers	0.39
Pumps	0.23
Tanks	0.40
Other equipment	0.07
Total direct costs	3.59
Total indirect costs	0.70
Engineering	0.43
Contractor fees	0.13
Contingencies	1.07
Total plant costs	5.91
Spare parts	0.03
Total investment costs	5.94
Operating expenses	
Annual O&M costs	0.233
Annual heat costs	0.213
Annual electricity costs	0.241
CO_2-capture cost	**\$/ton CO_2**
Capital	317
O&M	122
Heat	111
Electricity	126
CO_2 capture costs	676

The parameters used are: 0.291 t/h capture capacity, 20-year plant life, 8% discount rate, 90% capacity factor, \$10/GJ heat price and \$100/MWh electricity price. All costs are on a basis of 1st Qtr 2016 US$.

Sensitivity Analysis

The parameters used for the base case economic analysis are: 20 year plant life, 8% discount rate, 90% availability factor, \$10/GJ heat cost and \$100/MWh electricity cost. The effects of various economic parameters, such as plant life, heat and electricity unit cost, discount rate and equipment costs for the air capture process, on the economic performance were analyzed, with the results summarized in **Figure 9**. With variation of equipment costs in the range of 30%, the CO_2 capture cost varied between \$545 and \$808/ton CO_2. The discount rate also has a significant impact on the CO_2 capture cost. With a discount rate ranging from 4 to 12%, the cost of CO_2 capture ranged from \$588 and \$876/ton CO_2. Here, increasing plant life from 15 to 25 years, the cost of CO_2 captured varied by 10%, from \$655 to \$723/ton CO_2.

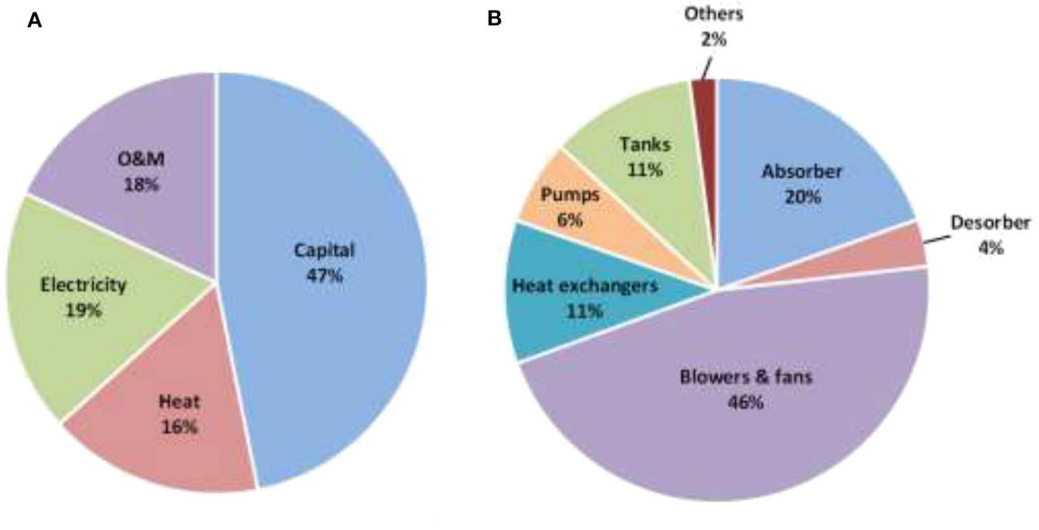

FIGURE 8 | (A) CO_2 capture cost distributions on capital, O&M, electricity and heat, and **(B)** capital cost distributions of major equipment in the MEA-based air capture.

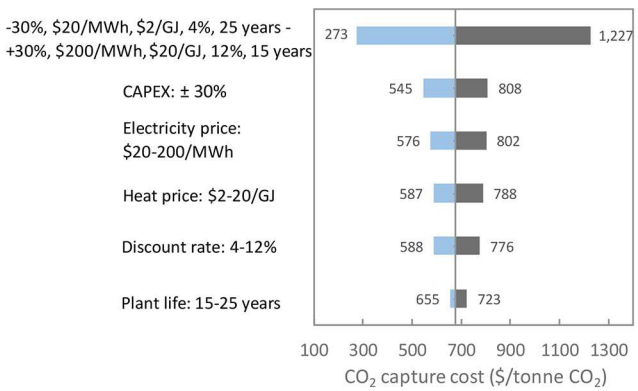

FIGURE 9 | Effect of economic variables on the CO_2 capture cost. The parameters used for the base case are: 20-year plant life, 8% discount rate, 90% capacity factor, $10/GJ heat price and $100/MWh electricity price.

A wide range of electricity prices from $20 to $200/MWh and heat prices from $2 to $20/GJ were considered in this study, providing various possibilities of electricity and heat sources applicable to the air capture process. The CO_2 capture cost varied by 39% from $576 to $802/ton CO_2 and 34% from $587 to $788/ton CO_2, as the prices of electricity ($20-$200/MWh) and heat ($2–$20/GJ) varied by a factor of 10, respectively. The use of zero-carbon energy, e.g., renewables or nuclear, in the air capture process is most likely required to avoid any additional CO_2 emission to air due to the energy consumption for the capture process.

Based on a sensitivity analysis on all variables, considering the most desirable and the most undesirable values for various economic parameters, the overall cost of capturing a ton of CO_2 ranges from $273 to $1227.

Energy and Cost in Comparison With Other Air Capture Studies

There are only a few studies that reported the required energy and cost for the capture of CO_2 from air. Using different technologies such as absorption and adsorption, the required thermal energy for the direct capture of CO_2 from air was reported to be almost 4–8 times larger than the required electrical energy. The cost of capturing one ton of CO_2 was reported to be between $100–1,000 (Keith et al., 2005, 2018; Heidel et al., 2011; House et al., 2011; Kulkarni and Sholl, 2012). The difference between the ranges reported for capture cost in this study and in literature originates from the fact that both were estimated using different technologies and economic assumptions around interest rates, plant life, electricity price and heat price etc. **Figure 10** shows the required electrical and thermal energy and total cost estimated in this work in comparison with the other air capture systems. It should be noted that there is insufficient detail on the energy consumption and cost of the other technologies that are still under development (shown in **Table 1**).

For the baseline case chosen in this study, the thermal energy required is 10.7 GJ/t CO_2 which is almost 3 times greater than the required electricity (~1.03 MWh/tCO_2). These are significantly larger than those reported in other studies. This is mainly due to different characteristics of this technology compared to others, for example the large recirculation of rich solvent is required here to prevent loading/flooding in the absorption column (it constitutes around 50% of total electricity requirement). **Figure 10** also shows that the total cost for capturing one ton of CO_2 from air using the new liquid absorption process was estimated to be around $676, in compared with the cost reported by the other researchers using their technologies ($93–232 in CE, $600 in CW, and $50 in GT). This includes $317 and $359 related to capital cost and operating cost, respectively.

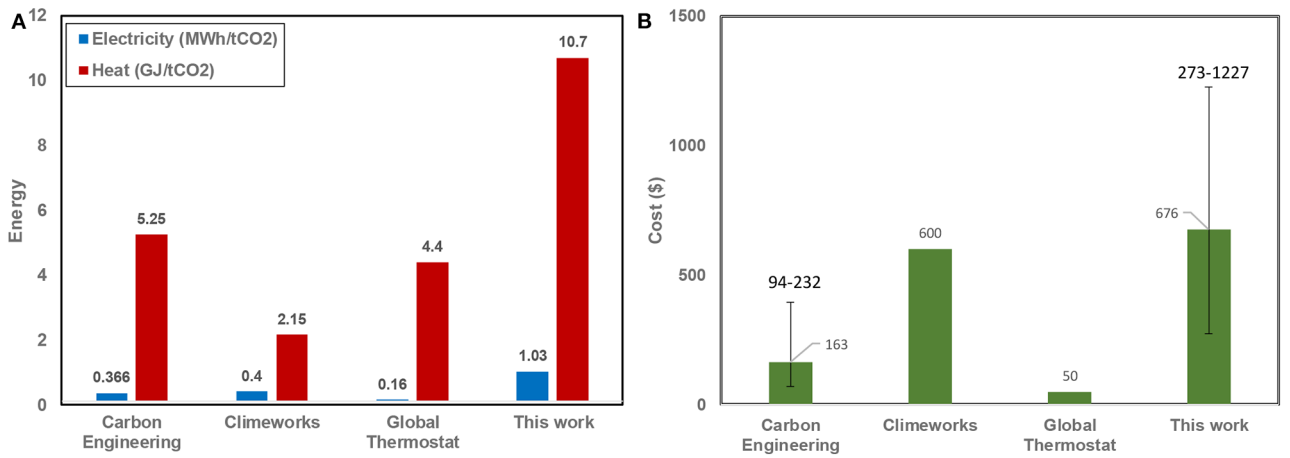

FIGURE 10 | (A) Energy consumption and **(B)** total cost reported in different studies for direct air capture processes. Note that $50/tCO$_2$ reported by Global Thermostat was the cost that they anticipated to achieve. No information whether they have achieved this. Also, this work and Carbon Engineering's study reported a range for the cost of the process, based on various economic parameters.

As previously indicated in **Table 1**, the only technology in the market that uses a liquid sorbent for air capture is the one developed and demonstrated by Carbon Engineering, based on sodium hydroxide, with subsequent transfer of CO_2 from sodium carbonate to calcium carbonate and CO_2 recovery via a calcination process. To compare, our estimated CO_2 capture cost is higher than the reported results of \$94–232/tCO_2 from Carbon Engineering. This is attributed both to the higher capital costs (\$255–379/tCO_2) and operating cost (\$290–\$430/tCO_2) in our system compared to the costs for Carbon Engineering one (capital: \$64-\$120/tCO_2, the operating cost: \$30-\$110/tCO_2).

The design of the Carbon Engineering gas-liquid contactor reduces the energy requirement and capital costs of blowers and fans. They use a horizontally oriented crossflow cooling tower, resulting in a low pressure drop, while in our study, we considered a vertically counter-current flow packed tower, significantly increasing the energy and capital costs of air movement in our system.

Based on the cost analysis described above, the other areas that can be improved in order to further reduce the capital and operating cost in the air capture system are:

1. If new air-liquid contactor is designed to optimize the contact between the large volume of air and small amount of liquid, this will eliminate the necessity for the large circulation rate/pumping of absorption liquids which consumes 0.54 MWh/tCO_2 electricity (around 50% of total electricity requirement) and hence reduce the capital and operating cost. In this case, the electricity cost reported in **Table 5** can be reduced by 50% to around \$63.
2. Development of new liquid absorbents and applying process modifications. If the reboiler temperature can be increased to 150°C, the absorbent heat requirement will be reduced by 60% to around 4 GJ/tCO_2. The cost for heat reported in **Table 5** will be therefore reduced by 60% to around \$44. This in fact necessitates new absorption liquids that are more stable at high temperature compared with MEA.

CONCLUSION

The technical and economic aspects of a conventional MEA-based absorption process for capturing CO_2 directly from air was simulated using a rate-base model in Aspen Plus. A benchmark condition was defined and further explored through a sensitivity analysis involving different parameters. It is concluded that:

- In an air capture system with a low capture rate, the heat required for the regeneration of absorption liquid per ton of captured CO_2 is significantly lower. However, a large volume of air needs to be processed and this results in a larger unit and hence a higher capital cost.
- Owing to the very low concentration of CO_2 in air, the amount of liquid required for the contact with air would be extremely low. To meet the operational requirement of a conventional packed column, a large liquid circulation around the absorber is required, resulting in a large electricity requirement.
- At the base case scenario, a capture rate of 50% was selected. The reboiler duty was 10.7 GJ/tCO_2 and the electrical energy requirement was 1.4 MWh/tCO_2. The absorber diameter and height were 10.4 and 4.4 m, respectively and the wash water section was 5 m in height.
- Owing to the large volume of air used in the air capture process, water and MEA losses due to evaporation were quite high. The addition of a wash water section to the absorber can reduce the MEA evaporation significantly down to 0.28 kg/ton of CO_2 (0.04 ppm), at the expense of increased capital costs.
- Using the standard chemical engineering design which may not necessarily required for the air capture process, the total estimated cost for this process was around \$1,690/ton CO_2. The capital cost and operating cost were \$1031/ton CO_2 and \$659/ton CO_2, respectively.

- The wash water section and absorber accounted for around 74% of total capital cost of this process. Using an alternative absorption liquid with negligible vapor pressure which allows for the removal of the wash water section, the capital cost will be reduced by $393 per ton of CO_2.
- The replacement of stainless steel packing and absorption column materials by cheaper materials like those used in cooling towers reduced the capital cost by another $323 per ton of CO_2.
- The techno-economic analysis of the air capture process designed based on the cooling tower technology and non-volatile liquid absorbent showed that the cost for CO_2 capture from air was, in the range of US$273 to US$1,227. Around 45% and 55% of this were attributed to the capital cost and operating cost, respectively.

In summary, this study provides an economic baseline for the air capture technologies that aim to use liquid-based capture process. Even though the energy requirement and cost of the baseline for such processes are still high with respect to the current CO_2-price, even for the CO_2-price in the framework of the Californian Low Carbon Fuel Standard (Low Carbon Fuel Standard, 2020), it is believed that the energy and equipment cost of the liquid-based air capture processes can be significantly reduced when this technology further matures and is scaled up to larger plant sizes. The use of cheap materials and more effective ways of contacting air and absorption liquids, using more robust and economical absorption liquids and innovative process modifications is required to further reduce the cost of this process. Also, if the CO_2 captured from atmosphere is utilized to produce synthetic fuels, then the process can be considered more economically favorable.

DATA AVAILABILITY STATEMENT

The datasets for this article are not publicly available because the data ownership and control must stay with CSIRO for propriety reasons. Requests to access the datasets should be directed to Paul Feron (paul.feron@csiro.au).

AUTHOR CONTRIBUTIONS

AK drafted the manuscript and analyzed and integrated the research results. KJ performed the process modeling and did the techno-economic analysis. PF conceived and designed the research work and analyzed research results. All authors contributed to the review and editing of the manuscript.

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SUPPLEMENTARY MATERIAL

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/fenrg.2020.00092/full#supplementary-material

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What Does It Take to Go Net-Zero-CO_2? A Life Cycle Assessment on Long-Term Storage of Intermittent Renewables With Chemical Energy Carriers

Jan Bernard Wevers[1], *Li Shen*[1]* *and Mijndert van der Spek*[2]

[1] Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, Netherlands, [2] Research Centre for Carbon Solutions, School of Engineering and Physical Sciences, Heriot Watt University, Edinburgh, United Kingdom

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Edited by:
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DNV GL, Norway

***Correspondence:**
Li Shen
L.shen@uu.nl

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The concept of net-zero-CO_2 power systems has gained increased attention by the EU goal to be a climate neutral continent by 2050. As potential pathways toward a net-zero-power system, this work analyzes future power systems based on intermittent renewable electricity with long-term storage through chemical energy carriers, so called Power-to-Fuel-to-Power systems, and a system based on the combustion of natural gas with 100% carbon capture and storage. The chemical energy carriers selected for electricity storage are hydrogen, methane and ammonia. Using life cycle assessment, we determine and compare the environmental impacts of 1 kWh of dispatchable electricity produced by the two pathways on seven impact categories. There was not one single pathway that had the most environmental benefits on all seven impact categories. Of the Power-to-Fuel-to-Power systems assessed the use of hydrogen for storage has the lowest environmental impact in all categories. Additionally, all the Power-to-Fuel-to-Power systems have a lower environmental impact on climate change, photochemical ozone formation and fossil resource depletion compared with the natural gas with carbon capture and storage system. The natural gas with carbon capture and storage system has a lower environmental impact on particulate matter formation, marine eutrophication and mineral resource scarcity. Our work is complemented by an analysis of pathways from a net-zero-direct-CO_2 to a life-cycle net-zero-CO_2-equivalent power system which is actually climate neutral, achieved by direct air capture of the residual CO_2 from the atmosphere. However, this leads to an increase in all other impact categories of 11% for the Power-to-Fuel-to-Power systems and 21% in the natural gas combustion with carbon capture and storage system. A system sizing study also highlights the very low capacity factors of the capital employed for electricity storage, raising the point of economic feasibility.

Keywords: energy storage, net-zero-CO_2-emissions, direct air capture, intermittent renewable energy supply, CO_2 capture and storage, chemical energy carriers, hydrogen, CO_2 based fuels

INTRODUCTION

The European Green Deal states that the European Commission aims to be the first climate neutral continent by 2050 (European Commission, 2019). The transition to a (near) zero-CO_2-emissions energy system is likely to depend on the availability of (i) vast amounts of emission-free electricity and (ii) the technologies and mechanisms to balance the large differences between intermittent Renewable Energy Supply (iRES) and end-user demand (Hertwich et al., 2014; Davis et al., 2018). Currently, gas and coal-fired power plants are used to balance the asynchronous production of the intermittent renewable electricity supply (iRES). In a future energy supply based on increased penetration of iRES, however, the long term (e.g., seasonal) storage of electricity is likely indispensable (Bussar et al., 2016).

Where there are many technologies proposed for short-term electricity storage, longer term (e.g., seasonal) storage of iRES is currently limited to storage in chemical energy carriers (e.g., through power-to-gas systems) and to a lesser extend pumped hydro. Pumped hydro is, however, only applicable when the topography is suitable and is best suited for storage in the order of days to weeks instead of weeks to months (Budt et al., 2016). The power-to-gas option usually starts with water electrolysis to produce hydrogen that can be stored in the subsurface directly or can react with CO_2 to produce methane or other hydrocarbons, which has the advantage of being able to use the existing natural gas infrastructure. Alternatively, hydrogen can react with N_2 to produce ammonia or ammonia derivatives (Grinberg Dana et al., 2016). Ammonia can be stored as a liquid at only 10 bars of pressure, which may be advantageous from the perspective of storage and energy required for pressurization. These chemical energy carriers can subsequently be used for the production of electricity, as described in Sutter et al. (2019), whence they are colloquially called Power-to-X-to-Power (P-X-P) systems.

Intermittent RES storage in both methane and ammonia would need large quantities of respectively CO_2 and N_2 as feedstock. As 80 percent of our atmosphere consists of N_2, it is relatively easy to obtain by an air separation unit (ASU) to produce pure streams of N_2 and O_2. Research on capturing CO_2 is mainly focused on the flue gasses from fossil fuel-fired plants as these contain high CO_2 concentrations and because it could reduce greenhouse gas (GHG) emissions of these plants if the CO_2 is subsequently stored (i.e., CO_2 capture and storage, CCS). In addition, direct air capture (DAC) of CO_2 is also being researched as a potential technology to reduce atmospheric CO_2 concentration and supply CO_2 (Wohland et al., 2018).

The interest for the combination of iRES with P-X-P systems is motivated by their potential to limit environmental impacts compared to existing, fossil-based electricity production systems. To that end, such systems need to have a very low carbon footprint and preferably be net-zero-CO_2 (Davis et al., 2018; Sutter et al., 2019), as well as present limited other environmental burdens. An effective and comprehensive method to analyze the greenhouse gas and other environmental impacts of a technology or system is Life Cycle Assessment (LCA). Some LCAs of iRES storage are found in the literature: Oliveira et al. (2015) compared compressed air energy storage, pumped hydro, hydrogen and several types of batteries and showed that the type of electricity feedstock is decisive for the performance of storage systems. Reiter and Lindorfer (2015) and Zhang et al. (2017) did research on the global warming potential of Power-to-Gas, both for hydrogen and methane, but the conversion back to electricity was not included. Both studies showed that the system could only reduce environmental impacts if renewable electricity was used.

Research has also been done into the economics of power to gas technology as a technology to store intermittent renewable electricity, and found that it might be difficult to make profitable (Götz et al., 2016). Grinberg Dana et al. researched Power-Ammonia-Power (P-A-P) systems, but only on a technical level and did not include an environmental assessment (Grinberg Dana et al., 2016). Sutter et al. (2019) performed a first screening assessment, including the system design, efficiency, and exergy analysis of net-zero-CO_2 systems for iRES storage. They included Power-to-Fuel-to-Power, as well as Power-to-Fuel-to-Propulsion and investigated hydrogen, methane, methanol and ammonia as energy carriers. They tentatively concluded that only hydrogen makes energetic sense as an electricity-derived propulsion fuel, as the other systems showed cyclic energy efficiencies as low as ten percent with limited upside for exergy improvements. Methane and ammonia were found to have potential use for iRES based Power-to-Fuel-to-Power in addition to hydrogen as they have infrastructure based advantages concerning the method of storage.

Here, we build on the work performed by Sutter et al. and other researchers, by investigating the environmental potential and trade-offs of net-zero-CO_2 systems for the long term (seasonal) storage of intermittent renewable electricity with chemical energy carriers. This work limits itself to the energy carriers that were earlier found to be most interesting from an energy efficiency perspective, i.e., hydrogen, methane, and ammonia. The first objective of this paper is to design and size P-X-P systems based on hydrogen, methane and ammonia to fulfill the role of long-term iRES storage in the future European electricity market, taking into consideration (intermittent) electricity supply and demand profiles and the European Commission's 2050 goal to become a climate neutral continent. The second objective is to investigate environmental performance and trade-offs between the systems by looking at multiple environmental impacts. These trade-offs are key to understand for the selection and investment of future electricity systems in the European Union. Since the complete CO_2 abatement of natural gas-fired power plants through CCS is considered another route toward zero emission electricity, this alternative is compared to the P-X-P systems to provide a point of reference.

Abbreviations: P-X-P, Power-to-Fuel-to-Power systems; P-H-P, Power-to-Hydrogen-to-Power system; P-M-P, Power-to-Methane-to-Power system; P-A-P, Power-to-Ammonia-to-Power system; NGCC, Natural Gas Combined Cycle; CCS, Carbon Capture and Storage (system); DAC, Direct Air Capture of CO_2; ACC, Ammonia Combined Cycle; LCA, Life Cycle Assessment; GHG, Green House Gasses; iRES, intermittent Renewable Electricity Supply; CWE, Central West Europe; ASU, Air Separation Unit; PEMFC, Polymer Electrolyte Membrane Fuel Cell; PEMEC, Polymer Electrolyte Membrane Electrolysis Cell.

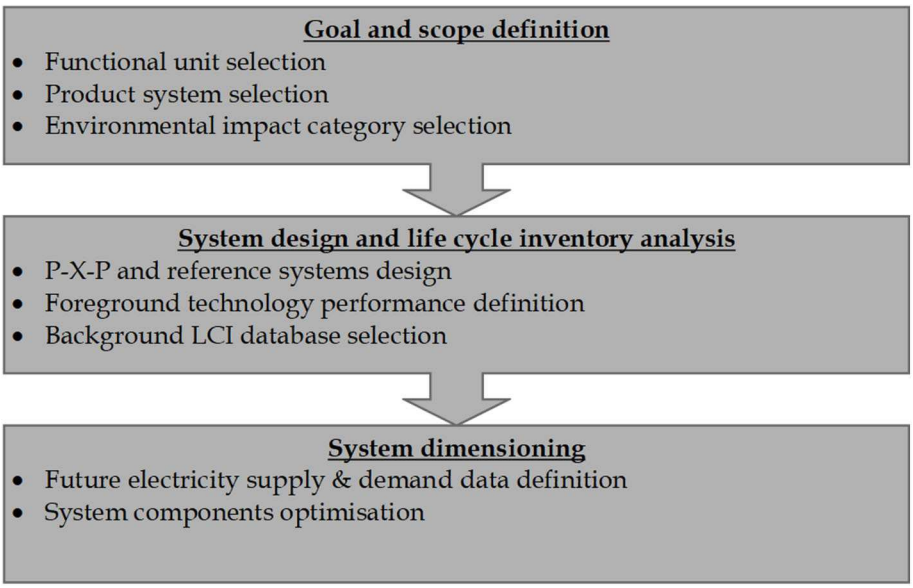

FIGURE 1 | Schematic of the research approach used in this study.

METHOD

As stated above, this work aims to investigate the environmental performance of future power systems, coupling iRES with long-term electricity storage. In order to quantify this performance, we integrated two methods: simplified power systems modeling to determine P-X-P system sizes given real iRES production and projected electricity demand profiles and an attributional LCA following ISO14044 standards (ISO, 2006; Weidema, 2018). The method section follows three steps, visualized in **Figure 1**, in which order the research was performed. First, goal and scope are defined for the system design and the LCA including the need for a new functional unit. Second, the system design model and the Life Cycle Inventory (LCI) model are explained. Third, the approach to the dimensioning of the systems using a customized electricity supply-demand model is explained.

Goal and Scope Definition

The goal of the LCA is to investigate the environmental impacts of different coupled iRES/P-X-P systems, subject to the constraint of net-zero-CO_2-emissions. This pushes the boundaries of traditional LCA, where CO_2 emissions are one of the investigated stressors (outputs), rather than constraint to zero (input). The goal is furthermore to understand the environmental trade-offs between the chemical energy carriers with respect to selected environmental indicators (see section Environmental Impact Categories), and the root cause of these stressors, to allow for policy and decision making.

With respect to scope definition, the electricity market in Europe is divided in seven Wholesale Electricity Markets where electricity is traded over national borders (European Commission, 2018). In this study, Central West Europe (CWE) was chosen as the geographical focus. The CWE market constitutes Austria, Belgium, France, Germany, the Netherlands and Switzerland. The CWE was selected because it has a large interconnection capacity between the member states and it uses a more advanced method to calculate the optimal use of this capacity, called flow-based market coupling (CWE NRAs, 2015; Amprion GmbH, 2018). Besides the good interconnection, these countries are located in a geographical position where seasonal storage is expected to become of importance (see also the iRES production profiles presented in section System Dimensioning and the Storage Requirements) and therefore make a useful case study.

Function and Functional Unit

Electricity is the main output function. However, 1 kWh of electricity produced by a renewable intermittent source cannot be directly compared with 1 kWh of electricity directly delivered from a thermal power plant as is still often done. The latter can generate and dispatch electricity according to demand, by cycling the plant up and down (Heuberger et al., 2016; van Der Spek et al., 2018). Conversely, a system with intermittent renewable electricity production without any electricity storage is not demand responsive, since its production is subject to the availability of wind, sun, or other natural phenomena (wind parks are however able to reduce production, so-called curtailment). The functions under discussion are noticeably different. Thermal power plants have the function of providing electricity, but also of grid balancing and providing inertia (Brouwer et al., 2015; Mac Dowell et al., 2017). IRES only fulfills the function of electricity production. Therefore, we here propose the functional unit of 1 kWh of *dispatchable* electricity. We define that electricity production in a system is dispatchable if it can respond to a given demand curve. As shown in **Figure 2**, this implies that iRES systems need to include an electricity storage function to provide

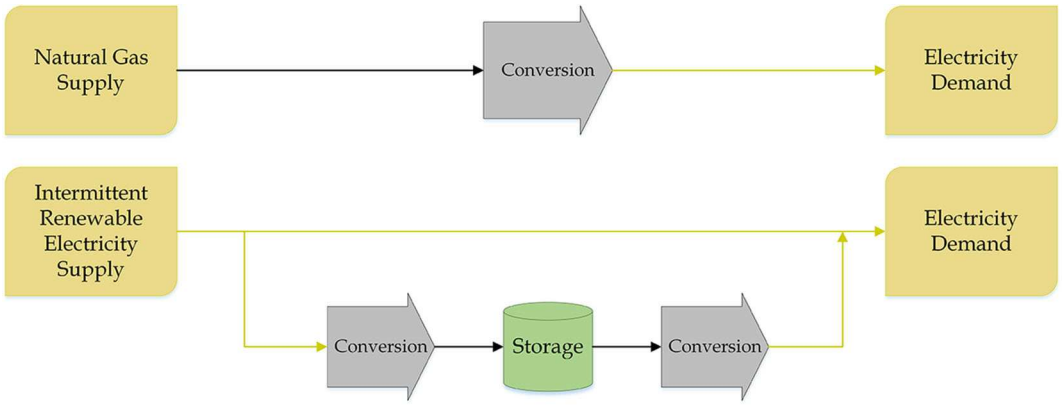

FIGURE 2 | Simplified system designs of the natural gas-based power system (above) and the P-X-P system (below). Yellow lines indicate electricity; black lines indicate chemicals energy carriers.

grid balancing. This storage is only used if the intermittent supply does not match the demand profile at a point in time.

Net-Zero-Direct-CO_2-Emission Constraint

The systems under consideration were configured in such a way, that their direct CO_2 emissions to the atmosphere were set to zero: either the system does not emit direct CO_2 by nature (e.g., renewable power-to-hydrogen-to-power) or the system is expected to take up the same amount of CO_2 as is emitted directly, for instance through CO_2 capture from a combustion process and/or the air. The systems thus have net-zero *direct* CO_2 emission. The net-zero-CO_2 constraint was here enforced because given European and global climate ambitions (IPCC, 2014, 2018; European Commission, 2019), it is virtually certain that iRES with P-X-P is needed to achieve a net-zero-CO_2 world.

Product Systems

Based on the defined function, functional unit, and the net-zero-direct-emission constraint, three P-X-P systems and two reference systems were analyzed in this study:

- Power-to-Hydrogen-to-Power (P-H-P)
- Power-to-Methane-to-Power (P-M-P)
- Power-to-Ammonia-to-Power (P-A-P)
- Future reference system: Natural gas combined cycle with carbon capture and storage complemented with direct air capture to mitigate residual direct CO_2 emissions (CCS)
- Current reference system: Natural gas combined cycle (NGCC).

For the P-X-P systems, a common first step in the chemical storage of intermittent renewable electricity is the production of hydrogen through the electrolysis of water. Proton Exchange Membrane Electrolysis Cells (PEMEC) were assumed in this research as they are projected to be the dominating technology in the near-future, replacing Alkaline Electrolysis Cells (AEC) (Schmidt et al., 2017), among others due to their increased operational flexibility.

The second step is the long-term storage of hydrogen. This can be done mechanically (high pressure, cryogenic), chemically (via Methane, Methanol or Ammonia) or through physisorption (Fullerenes, Nanotubes) (Niaz et al., 2015). Here, we assumed the same chemical energy carriers for storage as earlier done in Sutter et al. (2019): compressed hydrogen (100 bar), methane and ammonia. Methanol was excluded from this research because of the lower net system efficiency compared to methane and the fact that it lacks the inherent benefit of the existing natural gas infrastructure (Sutter et al., 2019). Methanol could have the potential benefit of allowing a coupling to the chemistry sector, but sector coupling is outside the scope of this paper and was not considered here. Ammonia was here included because it is a carbon free synthetic alternative to methane and hydrogen and thereby naturally closer to the goal of a net-zero-CO_2-emission system.

Two reference systems were chosen: first, a future reference system where an NGCC is fully abated by CCS, both post-combustion capture and DAC to conform to the net-zero-CO_2 constraint. This reference scenario was chosen because the use of natural gas in combination with CCS is often seen as an alternative option to decarbonize electricity supply. Second, a current reference system where the dispatchable electricity was supplied by an unabated Natural Gas Combined Cycle (NGCC), to provide a status-quo benchmark.

Environmental Impact Categories

The LCA evaluated the environmental impact of energy systems in seven impact categories (**Table 1**) that represent relevant environmental stressors to land, air, and water, human health and resource depletion. Based on the goal of the LCA that environmental trade-offs should be understood for the net-zero technologies, the choice of impact categories should not be limited to only carbon emissions. The seven impact categories were chosen because they provide a balanced view of important resources depletion (e.g., mineral resources and fossil fuel depletion) and the environmental impact associated with the direct emissions of the fossil fuel- fired thermal power plants,

TABLE 1 | Impact categories included in this LCA.

Impact category	Characterization factor	Short description	Example of relevant LCI data	Unit
Climate change (CC)	Global warming potential	Impact on radiative forcing of the atmosphere	CO_2, N_2O, CH_4, SF_6, CF_4, CFCs	kg CO_2 eq.
Photochemical ozone formation (POF)	Photochemical oxidant formation potential	Summer smog, formation of reactive chemical compound by sunlight	NO_x, NMVOC's	kg NO_x eq.
Particulate matter formation (PMF)	Particulate matter formation potential	Emission of aerosols with negative effect on human health	NO_x, NH_3, SO_2, PM2.5	kg PM2.5 eq.
Terrestrial acidification (TA)	Terrestrial acidification potential	Emissions of acid-forming substances	NO_x, NH_3, SO_2	kg SO_2 eq.
Marine eutrophication (ME)	Marine eutrophication potential	Excessive supply of nutrients	NO_3^- NH_3, NH_4^-	Kg N eq.
Mineral resource scarcity (MRS)	Surplus ore potential	Depletion of minerals	Fe, Ni, Al, Cu	Kg Cu eq.
Fossil resource scarcity (FRS)	Fossil fuel potential	Depletion of fossil resources	Oil, natural gas, coal	Kg oil eq.

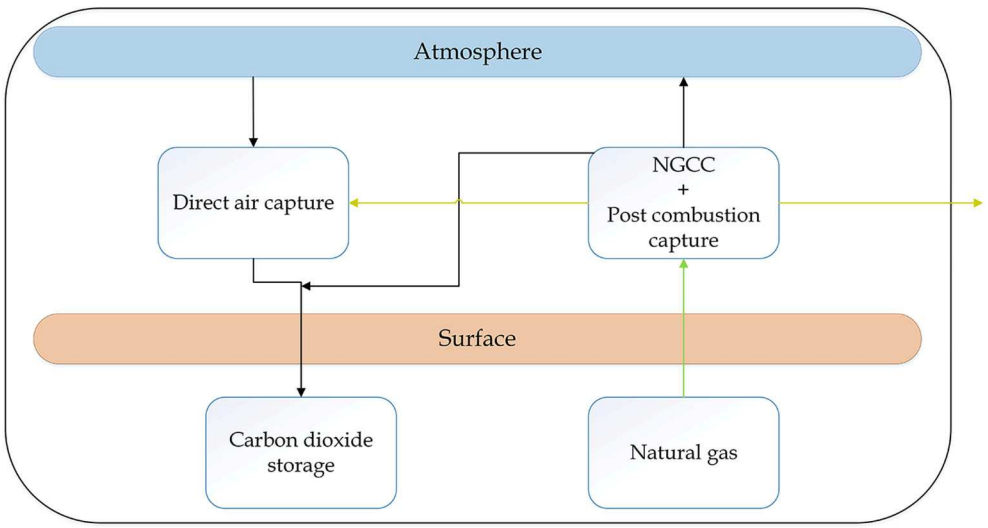

FIGURE 3 | System diagram of the future reference system (CCS): Yellow lines represent electricity, black is CO_2 and green is natural gas.

such as NOx, particulate matter and SO_2 (see **Table 1**). The life cycle impact assessment method used was the Hierarchist perspective in the ReCiPe 2016 methodology. The underlying assumptions and midpoint categorization factors can be found in Huijbregts et al. (2016).

System Design and Life Cycle Inventory Analysis

This section discusses the system designs and the key design parameters, followed by the methods applied for system dimensioning.

Future Reference System (CCS): Natural Gas Combined Cycle (NGCC) With Carbon Capture and Storage (CCS) and Direct Air Capture (DAC)

The future reference system is illustrated in **Figure 3**. Natural gas is supplied to an NGCC, where it is combusted to produce electricity. In Central West Europe, natural gas is supplied from different countries. The assumed NG basket is provided in the **Supplementary Information**.

Ninety-five percent of the CO_2 is captured using integrated post combustion CO_2 capture, that draws off steam from the steam cycle for sorbent regeneration. The specific energy requirement for post-combustion capture shows a sharp increase if the capture rate exceeds 90% (Mletzko et al., 2016), whereas the specific energy requirements for direct air capture are constant. The ratio of post-combustion capture and DAC where total energy losses are at their minimum was found to be 95% post-combustion capture and 5% DAC respectively. The captured CO_2 is compressed, transported and stored in a geological formation where it remains indefinitely if the formations are properly engineered and serviced (Bai et al., 2016). In this work, the potential leakage risk is considered to be negligible within the temporal scope

of the impact assessment (100 years) and is not taken into account.

The electricity requirement for DAC, which is 0.25 kWh/kg captured CO_2 (Wohland et al., 2018), can be directly obtained from the power produced within the system. The DAC heat demand, 1.75 kWh/kg CO_2 captured (Wohland et al., 2018), is also obtained from the system, where we assumed that the low temperature heat (∼100°C) is produced using an industrial heat pump with a Coefficient Of Performance (COP) of 2 (Arpagaus et al., 2018).

Power-to-Hydrogen-to-Power (P-H-P)

Figure 4 shows the P-H-P system where there are no direct CO_2 emissions. The energy that is needed for the production and compression of hydrogen is assumed to be supplied by intermittent renewables and thus the P-H-P system only runs when there is surplus iRES. Hydrogen production was assumed by PEMEC at 30 bar (Carmo et al., 2013) with subsequent compression to 100 bar (HyUnder, 2014). Hydrogen storage is expected to be facilitated underground in a salt cavern as they are present in CWE, have high storage capacities and have high flexibility regarding injection and withdrawal (IEA, 2012; Michalski et al., 2017). Considering the fact that it is not always possible to build the electrolyser exactly on top of the underground storage location, a transport distance of 50 km was assumed between hydrogen production and storage as well as between the storage location and the Polymer Electrolyte Membrane Fuel Cell (PEMFC) facility. Hydrogen losses due to transport are 5 times higher compared to natural gas in steel pipes, but when polyethylene pipelines are used the

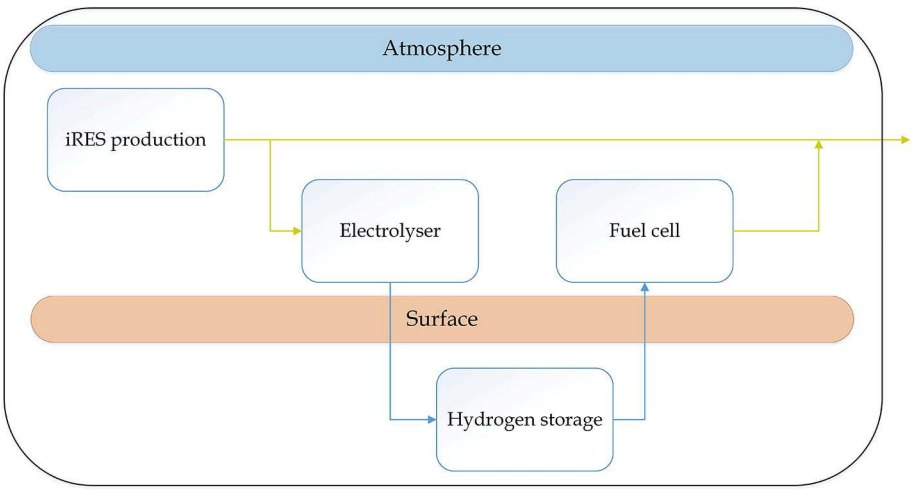

FIGURE 4 | System diagram of the P-H-P system: Yellow lines represent electricity, blue is hydrogen.

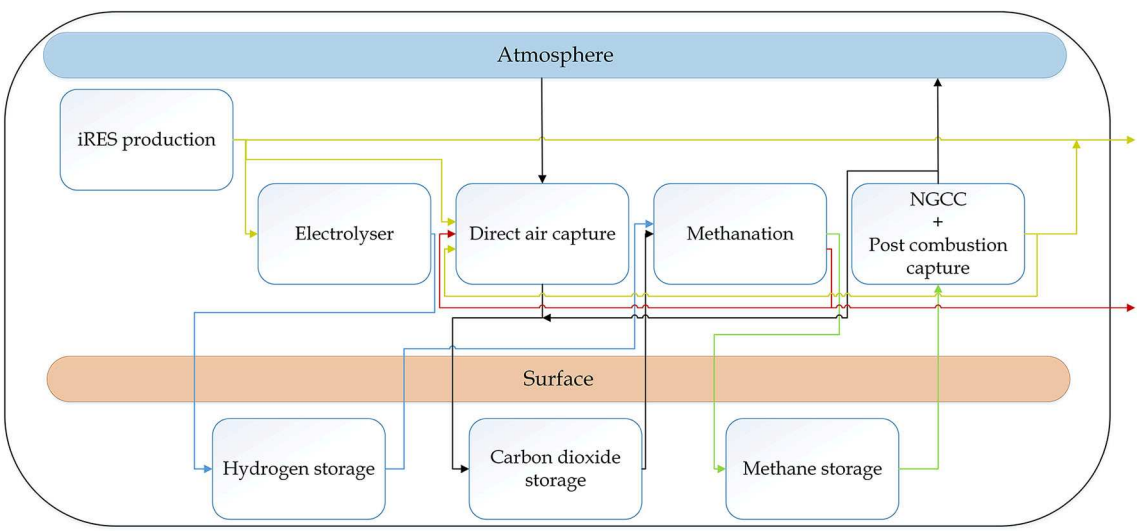

FIGURE 5 | System diagram of the P-M-P system: Yellow lines represent electricity, blue is hydrogen, black is CO_2, green is methane and red is heat.

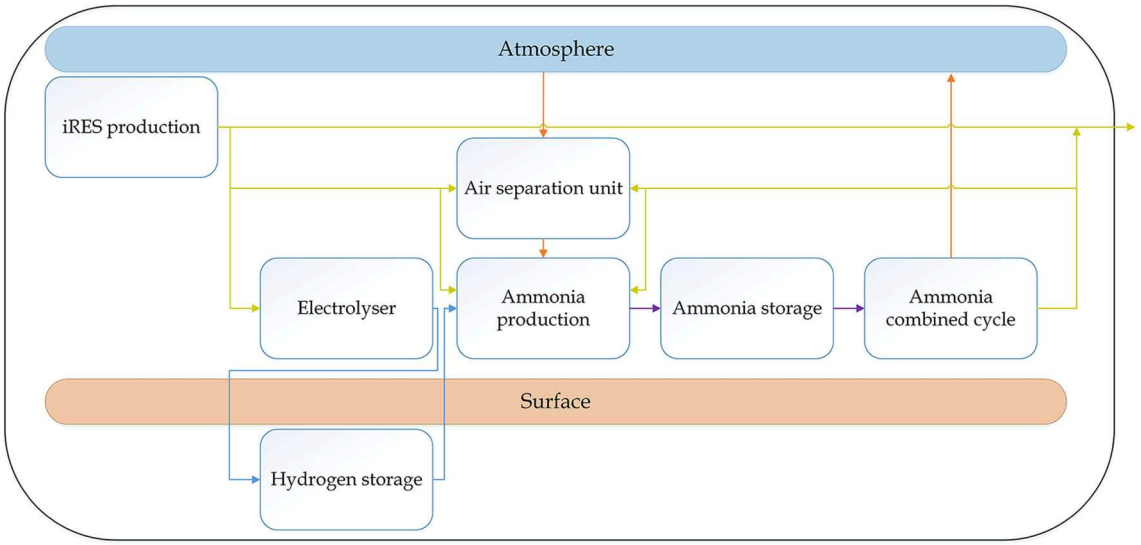

FIGURE 6 | System diagram of the P-A-P system. Yellow lines represent electricity, blue hydrogen, orange nitrogen and purple ammonia.

losses are merely 0.0005–0.001% of total transported volume (Haeseldonckx and D'haeseleer, 2007). For this research a loss of 0.00075% of total transported volume was assumed.

Power-to-Methane-to-Power (P-M-P)

The P-M-P system comprises of the methane production and the consecutive methane incineration in an NGCC with CCS in order to meet the net-zero CO_2 constraint (**Figure 5**). The technical specifications of the NGCC are identical to the NGCC described in the reference system, including the capture efficiencies, residual direct CO_2 emissions are recaptured from the air using DAC. The short-term hydrogen and CO_2 storage were added so that the methanation plant and DAC unit can run at a high capacity factor (thus also for the periods without iRES, see section System Dimensioning and the Storage Requirements), which is economically favorable. The produced methane was expected to use existing natural gas infrastructure for transport and storage, with an assumed distance from production to storage and storage to use of 50 km to account for the infrastructural needs and methane leakage.

Methane can be produced by hydrogenation of CO_2 and is widely researched in literature (Hutchings, 2002; Müller et al., 2011).

$$CO_2 + 4\,H_2 \rightarrow CH_4 + 2\,H_2O\ \left(+165.1^{kJ}/mol_{\,CO_2}\right) \quad (1)$$

Here, we assumed catalytic methanation as this is the only technology that is available on the required scale and data on this process is readily available (Götz et al., 2016). Catalytic methanation is a highly exothermic process and the excess heat, with temperatures exceeding 300°C, can be used for the heat and electricity demand of the DAC unit. If the heat exceeds the demand of the DAC unit, it can be used for other industrial purposes and was considered a useful by-product, replacing heat produced by an industrial Combined Heat and Power unit which combusts fossil fuels.

Power-to-Ammonia-to-Power (P-A-P)

Hydrogen for ammonia synthesis is nowadays produced by the reforming of natural gas. Here, however, the hydrogen is assumed to be produced by PEMEC. In contrast to the CO_2 cycle that is added in the P-M-P system, the P-A-P system has a nitrogen cycle. Ammonia is produced from hydrogen and nitrogen in the reaction shown below in the Haber-Bosch process.

$$N_2 + 3\,H_2 \rightarrow 2NH_3\ \left(-91.8^{kJ}/mol_{\,NH_3}\right) \quad (2)$$

Ammonia synthesis needs a high temperature and pressure, although there is on-going research done on catalysts that could operate under atmospheric conditions (Vojvodic et al., 2014). A pure stream of nitrogen is required for this reaction which is produced by an ASU. In analogy to the methane system, the system in **Figure 6** includes short-term hydrogen storage to increase the capacity factor and decrease the size of the ammonia production plant. Therefore, the electricity supply to the ASU and ammonia production plant have to be dispatchable and cannot fully originate from iRES. In times when iRES is limited the electricity is supplied from the ammonia combined cycle (ACC). The ammonia combined cycle is a new technology that has been researched and is expected to be technologically feasible (Institute for Sustainable Process Technology, 2017), although many uncertainties remain on its (environmental) performance (see discussion in section Combustion of Ammonia). Ammonia is stored as a liquid in tanks that are on site and under 10 bars of pressure.

Technology Performance Assumptions

The key technology performance assumptions are summarized in **Table 2**. The calculated mass and energy flows, the outputs of

TABLE 2 | Main technology performance assumptions used in this study.

Key processes	Electricity input requirement MWh/t	Heat input requirement MWh/t
Direct air capture[a]	0.25	1.75
Methane synthesis[b]	0.33	−3.008
Ammonia synthesis (incl. ASU)[c]	0.667	n/a
H_2 compression from 30 to 100 bar[d]	0.707	n/a
Conversion efficiency (in terms of LHV)		
H_2 production (PEMEC at 30 bar)[e]	70%	
PEMFC[f]	60%	
NGCC w/o CO_2 capture[g]	59%	
NGCC with CO_2 capture[h]	50.2%	
Ammonia Combined Cycle[j]	53.1%	
Post combustion CO_2 capture rate[k]	95%	

[a]*Wohland et al. (2018)*, [b]*Müller et al. (2011)*, [c]*Valera-Medina et al. (2018)*, [d]*Aspen Plus simulation assuming 72% isentropic efficiency*, [e]*Götz et al. (2016)*, [f]*Polymer Electrolyte Membrane Fuel Cell (US Department of Energy, 2017)*, [g]*IEA (2012)*, [h]*based on IEA (2012), adjusted to include 95% capture efficiency instead of 90%*, [j]*Institute for Sustainable Process Technology (2017)*, [k]*Energetically optimal capture efficiency per inhouse calculations. From a 95% capture rate onward, the impact of CO_2 capture on net NGCC efficiency is higher if PCC is assumed instead of DAC. n/a, not applicable.*

system designs step (sections System Dimensioning and System Dimensioning and the Storage Requirements), were used as the input for the life cycle inventory modeling. The detailed foreground data that was used as LCI data is presented in the **Supplementary Information**, the background data was obtained from the EcoInvent database v3.5.

System Dimensioning

Storage and Component Sizing Model

One of the critical parameters in our system analysis (see also section Hourly vs. daily vs. weekly data points) is the percentage of iRES that is to be stored to achieve the desired function of dispatchable electricity. Here, an optimization model was applied, using electricity supply and demand data to determine the amount of electricity storage needed and therefore the size of the different systems' components. We acknowledge this is a simplification because our systems would in reality not be stand-alone, but be part of a complex power system including many different types of electricity generators, storage options, and country interconnections (e.g., Zappa et al., 2019). This simplification, however, allows the comparative LCAs of the systems studied that we seek to undertake here.

To determine the dimensions of the different components and flows of the systems, an electricity supply-demand model was specified in Python. This model calculated, based on estimated future demand and real iRES production curves using Equation (3) (see also section Electricity Supply and Demand Data), the necessary storage capacity of the system using Equation (4) (here presented for hydrogen):

$$U_t - P_t = D_t - S_t * SF \tag{3}$$

$$H_t = H_{t-1} + P_t * \eta_{el} - \frac{U_t}{\eta_{fc}} \tag{4}$$

Where, D_t and S_t are the demand and supply of electricity at time t, P_t, H_t, and U_t are the production, storage, and use of hydrogen at time t, η_{el} and η_{fc} are the electrolyser and fuel cell efficiencies, and SF is the storage systems scaling factor.

The model minimizes the total iRES production needed to fulfill a given demand profile as a function of the storage system scaling factor. This method of minimization prevents the model from producing and using the chemical energy carrier at the same time, which in real life would be unlikely [see Equation (5)]:

$$Minimize \sum_{t=1}^{365} (P_t\,(SF)) \tag{5}$$

$$s.t.\ H_t \geq 0 \tag{6}$$

$$H_0 = H_{end} \tag{7}$$

Equations 6 and 7 are constraints stating that the chemical energy stored cannot become negative and that the energy stored at the end of the year equals the energy stored at the beginning. This is added so the system does not get any "free" energy, as the system starts with a certain amount of stored energy.

Electricity Supply and Demand Data

The future demand curve for the supply-demand model was taken from Zappa et al. (2019). It is based on assumptions in the EU Energy Roadmap 2050 on increased electricity demand for heating (500 TWh y^{-1}) and transport (800 TWh y^{-1}) in the EU (European Commission, 2012). Zappa et al. used the 2015 demand profiles for EU countries from the ENTSO-E database and added the increased demand for heating and transport (Zappa et al., 2019). Here, the demand profiles of the countries constituting Central West Europe (CWE) where added up to obtain a demand profile for the total CWE region. This means we made the simplifying assumption that there will be unlimited transmission capacity between these countries. Our systems were not expected to fulfill the demand for the complete CWE region, but were designed to have a maximum capacity of 1 GW (the size of a typical large-scale thermal power plant). Therefore, the CWE demand curve was scaled such that the maximum total supply it reached was 1 GW.

The iRES production profiles were constructed using the "Renewables.ninjas" database (Pfenninger and Staffell, 2016; Staffel and Pfenninger, 2016). For wind production, the "long-term future fleet" datasets were used; for the solar energy production, the MERRA-2 dataset was used. These datasets contain 30 years (1985–2015) of hourly values for the capacity factor of wind and solar production and are available per country. To predict the total production of wind and solar energy in CWE in 2050 these capacity factors were multiplied by the planned installed capacity in 2050 in these countries, based on the "Energy, Transport and GHG emissions Trends 2050" from the

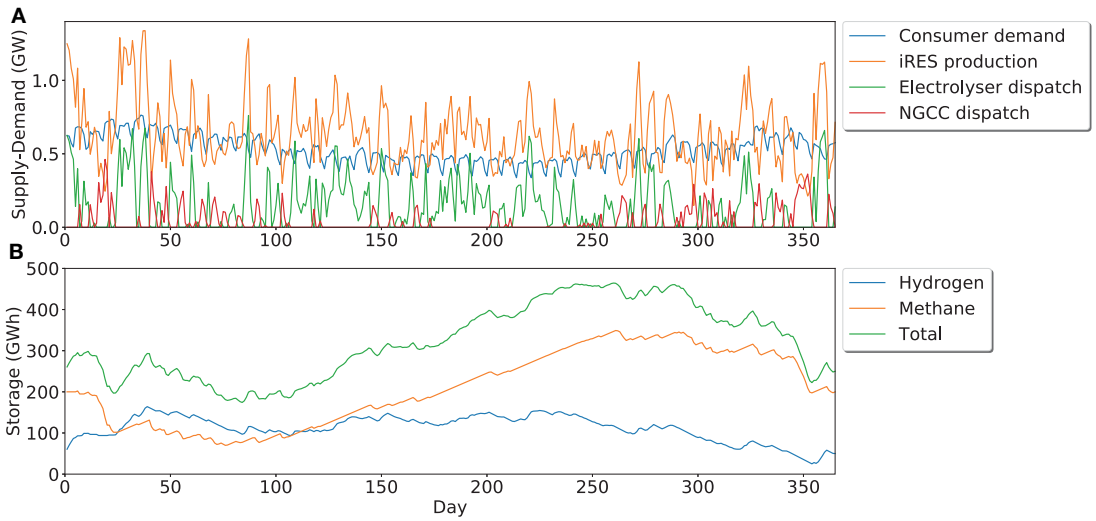

FIGURE 7 | (A) Daily fluctuations in the projected demand and supply for the P-M-P system (shown as lines "Consumer demand" and "iRES production") using 2015 meteorological data, and the resulting dispatch capacity required for the electrolyser and NGCC (GW). **(B)** Hydrogen and methane storage requirements (GWh) and the two curves combined. Day 1 as January first. The small peak in hydrogen production around day 45 is represents a peak in wind power production in February 2015.

EU (European Commission, 2016). The wind and solar profiles of the CWE countries were combined to obtain the iRES supply profiles of the whole CWE. Because the used iRES supply dataset includes 30 years of weather profiles we obtained 30 different potential CWE iRES supply profiles. The system dimensions were determined such that the systems can operate in all 30 years. Both the demand and supply profiles are can be found in detail in the **Supplementary Information**.

RESULTS

System Dimensioning and the Storage Requirements

Figure 7 shows the storage requirements resulting from the projected supply-demand optimization for one exemplary year. The left **Figure 7A** shows the modeled daily supply and demand of the P-M-P system using the 2015 meteorological data and the required dispatch (in GW) of the electrolyser and the NGCC. The system's maximum hourly consumer demand was set to 1 GW (see section Electricity Supply and Demand Data). Because the hourly data points were aggregated into daily points, the maximum of the daily averaged data is lower than 1 GW (763 MW). **Figure 7A** also shows that for the P-M-P system, as expected, the electrolyser is operated more in the summer months, whereas the NGCC delivers more electricity in the winter months. This is reflected in the fluctuations of the total amount of energy storage required. **Figure 7B** shows that the systems indeed provide seasonal electricity storage, as the stored amounts of energy carriers dip before, and peak after the summer. Exemplary profiles for the P-H-P and P-A-P systems can be found in the **Supplementary Information.**

Table 3 shows the results of the key design parameters based on the required electricity storage capacity for all three P-X-P systems. The capacity factors of the electrolyser are around 17% for all three systems, where the capacity factors of the power plants and fuel cell are around 8%. These low capacity factors show that a large part of the electrolyser capacity remains unused during the year, which may have implications for economic feasibility. Although economics are outside the scope of this paper, it is worth noting that PEMECs are expected to have a capital cost between 250 and 1270 €/kW in 2030 (FCH JU, 2015) and that such low capacity factors would imply inefficient and therefore expensive use of installed capital. Similarly, construction of a power plant that operates <10% of the time may be expected to be unprofitable (unless the power plant has surpassed its economic lifetime, or if it would be possible to use the remaining capacity of the NGCC for the combustion of natural gas with CCS, net-zero hydrogen or ammonia).

In both the P-M-P and P-A-P systems there is still the need for a relatively sizeable hydrogen storage of 330–350 GWh. This results from the assumption of at least 90% capacity factors of the methane and ammonia production plants (which was made taking into account the economic feasibility of methanation and ammonia production). If this constraint is deleted, the hydrogen storage size would greatly reduce. However, this would, in turn, lead to an increase in the size and decrease in the capacity factor of the methane and ammonia production, indicating a trade-off in system design where a full economic analysis would be required to determine a potential optimum.

For the P-M-P system, if the 2015 weather data is used, the methane storage fluctuates between 50 GWh and 350 GWh (see **Figure 7**). However, the methane storage needed for the P-M-P system to function over the complete 30 years of weather data in **Table 3** is 859 GWh. This shows that there is a large difference in storage capacity requirement over the years and that this strongly depends on the production profile of the renewable electricity.

TABLE 3 | Key design parameters as the output from the system dimensioning model.

Product systems	P-H-P	P-M-P	P-A-P
Input values for the system dimensioning model			
Estimated electricity demand (GWh/yr)	4628	4628	4628
Calculated iRES production (GWh/yr)	5500	5647	5628
Intermediate outputs			
Electricity directly to grid (GWh/yr)	4221	4254	4250
Electricity stored (GWh/yr)	1279	1392	1378
Electricity from Power plant/fuel cell (GWh/yr)	407	373	377
Roundtrip efficiency	31.8%	26.8%	27.4%
Fraction of demand delivered by power plant/fuel cell	8.8%	8.1%	8.1%
Fraction of electricity stored	23.2%	24.7%	29.8%
Capacity factor electrolyser	16.6%	17.3%	17.2%
Capacity factor Methane/Ammonia synthesis plant	n.a	92.5%	91.6%
Capacity factor Power plant/Fuel cell	8.4%	7.8%	7.9%
Optimized capacities of key components			
Electrolyser size (MW)	881	859	913
Power plant/Fuel cell size (MW)	553	548	549
Methane/Ammonia plant (MW)	n.a	110	110
Hydrogen storage (GWh)	1140	347	330
Methane/Ammonia storage (GWh)	n.a	859	763

It also shows the capacity factor and minimum size of all components and storage media necessary in order to operate in all 30 years of weather data (1985–2015) investigated. The input values and intermediate outputs are average values over the 30 years of weather information used. The Optimized capacities are absolute (maximum required) capacities. n.a, not applicable.

For the P-X-P systems, the total required storage is ∼1.1 TWh for the dispatchable capacity of 1 GW. With the maximum electricity demand in the CWE region in 2050 predicted to be 385 GW (Zappa et al., 2019), 424 TWh of electricity storage is needed to deliver all electricity in the CWE region in 2050. To put this into perspective, there is currently around 640 TWh of natural gas storage in the CWE region (Gas Infrastructure Europe, 2018). If natural gas usage declines in the coming decades and if the geology allows it, this excess storage capacity could be used for hydrogen or synthetic methane instead (DBI-GUT, 2017).

Finally, the amount of electricity that goes through storage will influence the technical and environmental performance of the systems. If a higher percentage of renewable electricity needs to be stored, it will decrease the overall system efficiency due to the energy losses of storage. Consequently, the required sizes of the different components will also be affected. This point is further discussed in section Data Uncertainty.

Results of Environmental Life Cycle Assessment

The system sizing is fed into the LCA, here presented in the following three subsections. First, the overall comparison of the environmental impacts is addressed to allow discussing the environmental trade-offs between the investigated P-X-P systems (with net zero direct emissions) and the two reference systems (i.e., NGCC and fully abated NGCC). Second, each impact category will be interpreted in detail. Last, the environmental impacts are interpreted based on the geographical scopes of the value chain.

Overview Comparison of Environmental Impacts

Figure 8 shows the life cycle environmental performance of the five electricity supply systems studied. Comparing the two NGCC reference systems, the figure shows that fully abating the direct CO_2 emissions of the NGCC system ("CCS" in **Figure 8**) reduces its life cycle climate change (CC) impact by around 70% compared to the unabated NGCC system, but it leads to an increased impact on all other impact categories. The 70% of climate change reduction is in the range which was found in earlier studies by Corsten et al. (2013) and Singh et al. (2011), where CCS implementation to an NGCC decreased CO_2-equivalent emissions by 60–80% while increasing all other impacts. Note that the CCS system in this study assumed a higher CO_2 capture rate (95%) at the NGCC compared to the systems analyzed by Corsten and Singh (90% capture rate); also, in our study DAC was assumed to reduce the remaining 5% of emissions in the foreground. The noticeable increase (∼25%) in fossil resource scarcity is largely due to the reduced efficiency of the NGCC and thus the increased use of natural gas, which was also observed by the aforementioned authors.

Compared to the two NGCC systems, the P-X-P systems offer substantial environmental impact reductions in three categories out of seven, namely, 80% reduction in climate change (CC), 40–50% reduction in photochemical ozone formation (POF) and 90% reduction in fossil resources scarcity (FRS). However, the P-X-P systems have higher impacts on PM formation (PMF), marine eutrophication (ME) and mineral resource scarcity (MRS), than the NGCC systems. For terrestrial acidification (TA), the NGCC case has the lowest impact whereas the P-A-P system has the highest impact. The detailed interpretation of each impact category will be provided in the following.

Breakdown by Key Processes

Figure 9 shows the breakdown of the LCA results by key processes for each environmental impact category. The natural gas input includes the extraction and transport of natural gas. The renewable electricity process includes the production and installation of PV and wind capacity. Infrastructure therefore does not include PV and wind capacity but only the NGCC, ACC, fuel cell, electrolyser, and storage assets.

Impacts resulted from the emissions from the fuel input, being either natural gas or renewable electricity, dominate the environmental impact in the systems. The current reference NGCC system is the exception where the direct emissions are responsible for the largest share (80%) of the CC (see **Figure 9A**), 91% of PMF (**Figure 9C**) and 47% of the POF (**Figure 9B**).

The direct emissions at the plant also contribute a significant fraction to the impacts of POF (16%) and PMF (18%) for the P-A-P system due to unburned ammonia and large quantities of NO_x

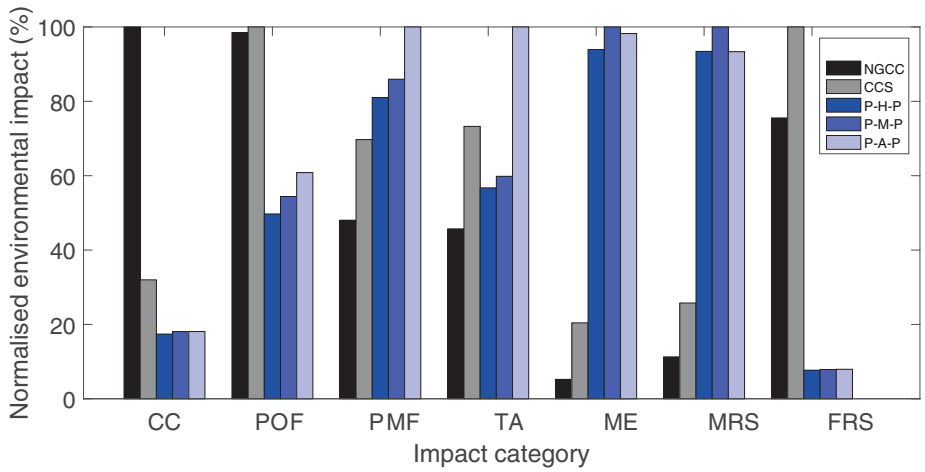

FIGURE 8 | Comparison of cradle-to-factory gate environmental impact of 1 kWh dispatchable electricity for the studied cases on seven selected impact categories. Results normalized to the system with the highest impact (set to be 100%). CC, Climate Change; POF, Photochemical Ozone Formation; PMF, Particulate Matter Formation; TA, Terrestrial Acidification; ME, Marine Eutrophication; MRS, Mineral Resource Scarcity; FRS, Fossil Resource Scarcity.

in the flue gas (See **Figures SI4**, **SI5**). Improving the combustion rate of ammonia could lower this high impact, but the full combustion of ammonia is known to be challenging due to its low flame speed (Institute for Sustainable Process Technology, 2017).

The direct emission of ammonia at plant in the P-A-P system is also responsible for 43% of the terrestrial acidification impact (see **Figure S16**), because ammonia is a strong acidification gas with a characterization factor of 1.96 kg SO_2 eq./kg ammonia. The unburned ammonia and the rate of NO_x emissions at ammonia combustion are however a source of large uncertainty, and they are therefore further addressed in section Combustion of Ammonia.

By adding CCS and DAC to the NGCC the climate change (**Figure 9A**) impact decreases by 70%, The CC impact of CCS system is dominated by the background processes, mainly originated from the production of natural gas. Due to the decreased efficiency of the NGCC with CCS, the natural gas input per kWh produced, and with it the methane emissions from natural gas production and transport losses (fugitive emissions), increases. This increase in methane emissions therefore slightly negates the positive effects of the CO_2 capture and storage.

For the three P-X-P systems, the impacts from the production of renewable electricity dominate (89–98%) in all seven categories. The impacts are associated with the manufacturing of PV panels and wind turbines for which aluminum and copper are mined and the manufacturing processes use fossil-fuel based energy. For instance, for climate change, 47% of the impact is caused by coal-based electricity; for fossil resources scarcity, 40–45% of the impact is caused by hard coal, 25–30% is caused by natural gas and ∼20% is caused by crude oil.

For the two reference systems, the impacts from natural gas production are mainly contributed by the fugitive methane emissions during long-distant pipe transportation, electricity needed for compression and emissions during natural gas extraction.

The impact of other infrastructure (electrolyser, storage of fuel, fuel cell and natural gas/ammonia combustion facility) of the P-X-P systems is relatively low. It only contributes 1–5% of the life cycle impact, with the exception of the mineral resource scarcity impact (9–12%). Infrastructure impact is highest in the CCS system, mainly due to the CO_2 pipeline and storage. A breakdown by substance for all impact categories can be found in the **Supplementary Information**.

Geographical Origin of the Environmental Impacts

One of the key findings based on the breakdown results is that the environmental impacts of the net-zero electricity systems are strongly associated with mining of aluminum and copper, the manufacturing of PV panels and wind turbines, and the extraction and transport of natural gas for the NGCC-based systems. If the EU wants to minimize the impacts of these net-zero electricity systems it is important to pay attention to these environmental hotspots occurring outside of the EU.

Figure 10 shows the geographical origin of the environmental impacts of the two net-zero electricity systems: CCS and P-M-P. The other two P-X-P systems resemble much to P-M-P systems in terms the geographical distribution of the impacts.

In the CCS system, the climate change impact resides for more than 60% outside of the EU borders, mainly due to natural gas imported from Russia (45% of total). The P-M-P system has a larger uncertainty in the geography than the CCS system as more of the impact has an unknown location, but still more than 48% of the climate change impact resides outside of the EU borders, as most PV panels today are manufactured in China. For photochemical ozone formation we see a similar trend, where the P-M-P system has at least 36% of the impact originated outside of EU borders.

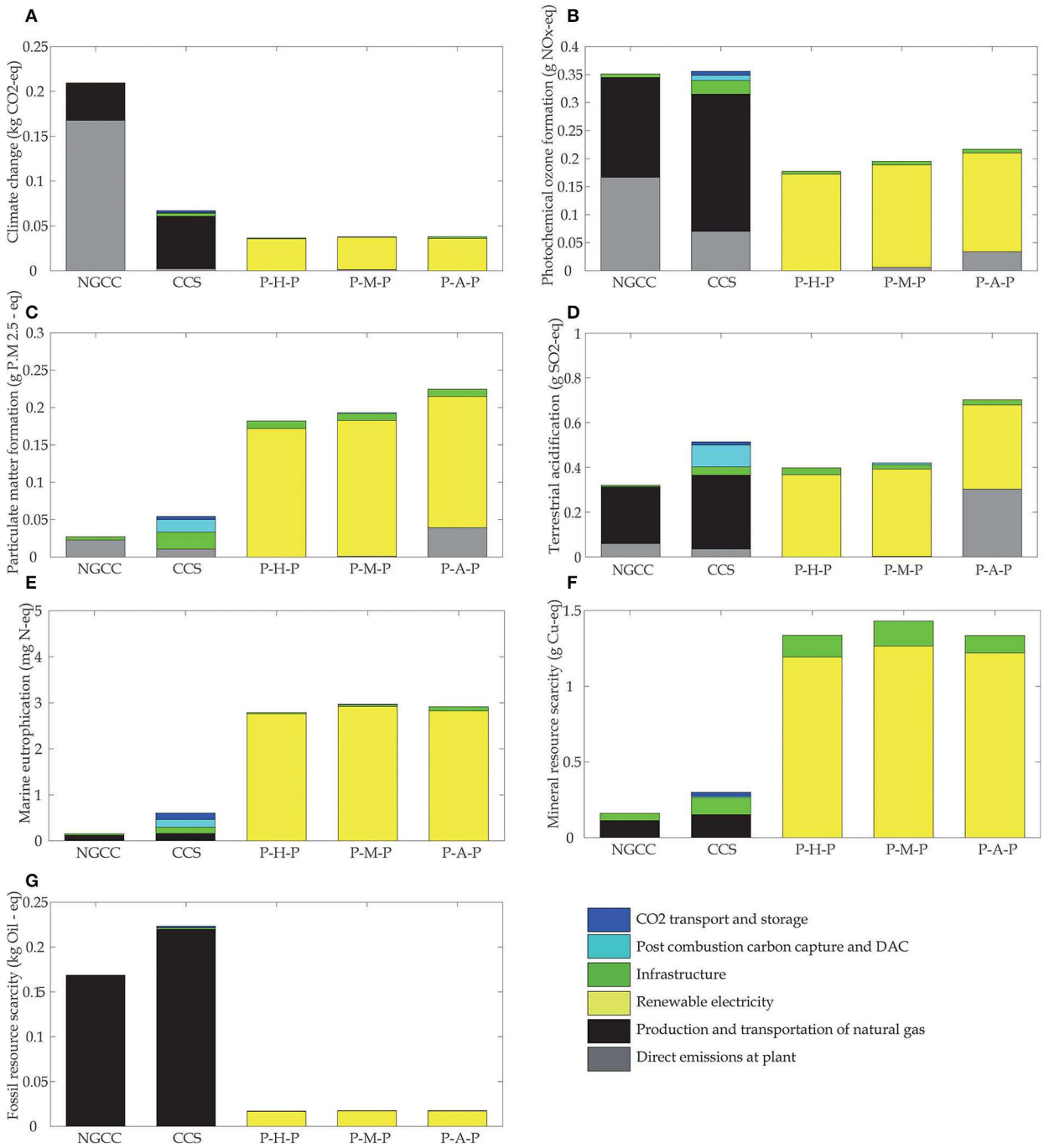

FIGURE 9 | Cradle-to-factory gate impacts of 1 kWh dispatchable electricity of the five studied product systems, breakdown by key processes. **(A)** Climate change, **(B)** Photochemical ozone formation, **(C)** Particulate matter formation, **(D)** Terrestrial acidification, **(E)** Marine eutrophication, **(F)** Mineral resource scarcity, and **(G)** Fossil resource scarcity.

DISCUSSION

Hourly vs. Daily vs. Weekly Data Points

In the modeling approach it was chosen to aggregate the hourly supply and demand data into daily data points. Thereby, the P-X-P systems do not provide to balance intraday fluctuations but rather fulfill their long-term storage role. The share of the electricity demand that is provided by the storage was 8–9% in contrast to 12–13% if the hourly data points would have been used. Rodriquez et al. found that if 100% renewable production in Europe, assuming unlimited interconnection and

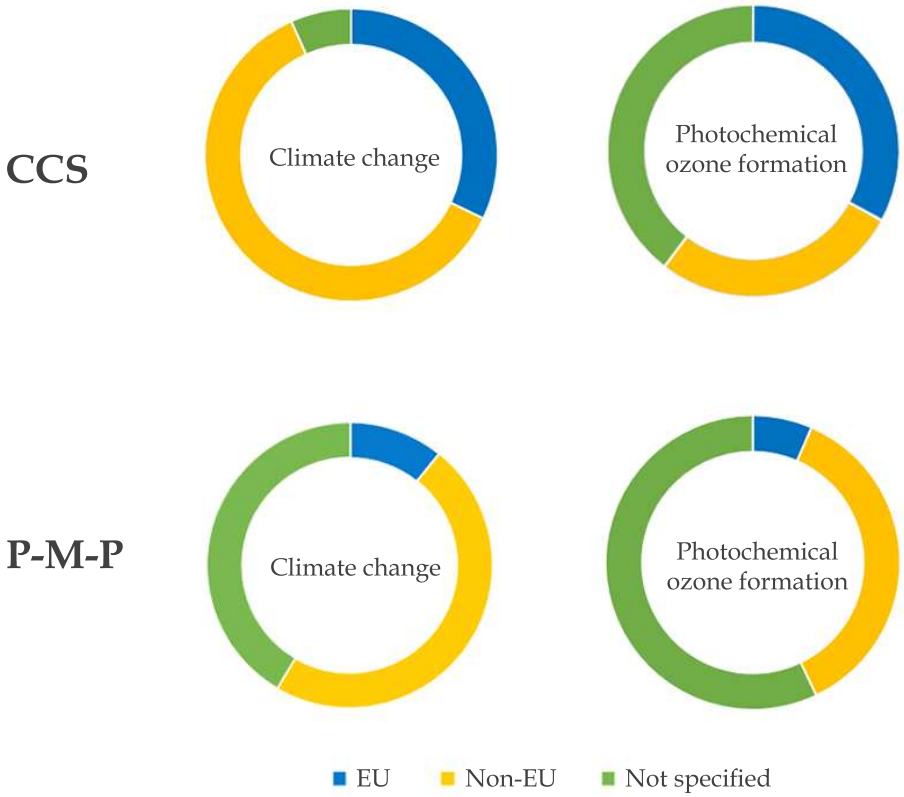

FIGURE 10 | Geographical origin of climate change impact and photochemical ozone formation impact for selected systems.

using hourly data, almost 15% of demand needs balancing (Rodríguez et al., 2014).

To focus even more on seasonal energy storage, weekly aggregated data points could have been modeled as well, which would have resulted in only 4.5–5.5% of electricity demand passing through storage. As a consequence, less iRES passing through storage would further reduce the climate change impact of the P-X-P systems by 7–8% (see also the sensitivity analysis in section Data Uncertainty). However, it would also reduce the capacity factor (e.g., to ∼4 and 2%) of the electrolyser and fuel cell/NGCC/ACC, making the system even less economically attractive. This highlights a difficult trade-off between the total environmental impact and the economic feasibility for chemical energy storage used for net-zero electricity supply.

Data Uncertainty

A one-way sensitivity analysis was conducted to identify the sensitive system parameters and assumptions. The results are shown in **Figure 11** for the four net-zero electricity supply systems for climate change. Other impact categories largely resemble climate change as most environmental impacts are concentrated in the renewable electricity supply and natural gas supply.

The CCS system is the most sensitive to changes related to the natural gas supply and consumption, given that the natural gas supply chain is the largest source of GHG emissions in the background system. The uncertainties lie mainly in the fugitive methane emissions that take place during production and transport, and in the efficiency with which natural gas is converted to power in the NGCC. For the supply chain, the origin of the gas plays an important role. There is a large potential to improve, since for example Russian gas is known to lose 0.23% per 1,000 km during transport (Dones et al., 2005). The efficiency of gas turbines is also a sensitive parameter for the CCS system (see **Figure 11**). However, the NGCC is a mature technology and it is not expected that the efficiency of gas turbine will substantially improve (i.e., more than single percentage points) unless breakthrough technologies reach the market.

The P-X-P systems are most sensitive to changes in the environmental burden of the renewable electricity input (iRES impact), as also evident by the breakdown results that renewable electricity production is the most important contributor (section Breakdown by Key Processes). Interestingly, an increase in the "percentage of iRES stored" increases the climate change impact. This is expected as the storage system increases the renewable electricity requirement because of the increased energy losses in the conversion processes and the need for more infrastructure. It is therefore key to limit the need for electricity storage to limit the life cycle impacts, if possible, e.g., by means of demand side management.

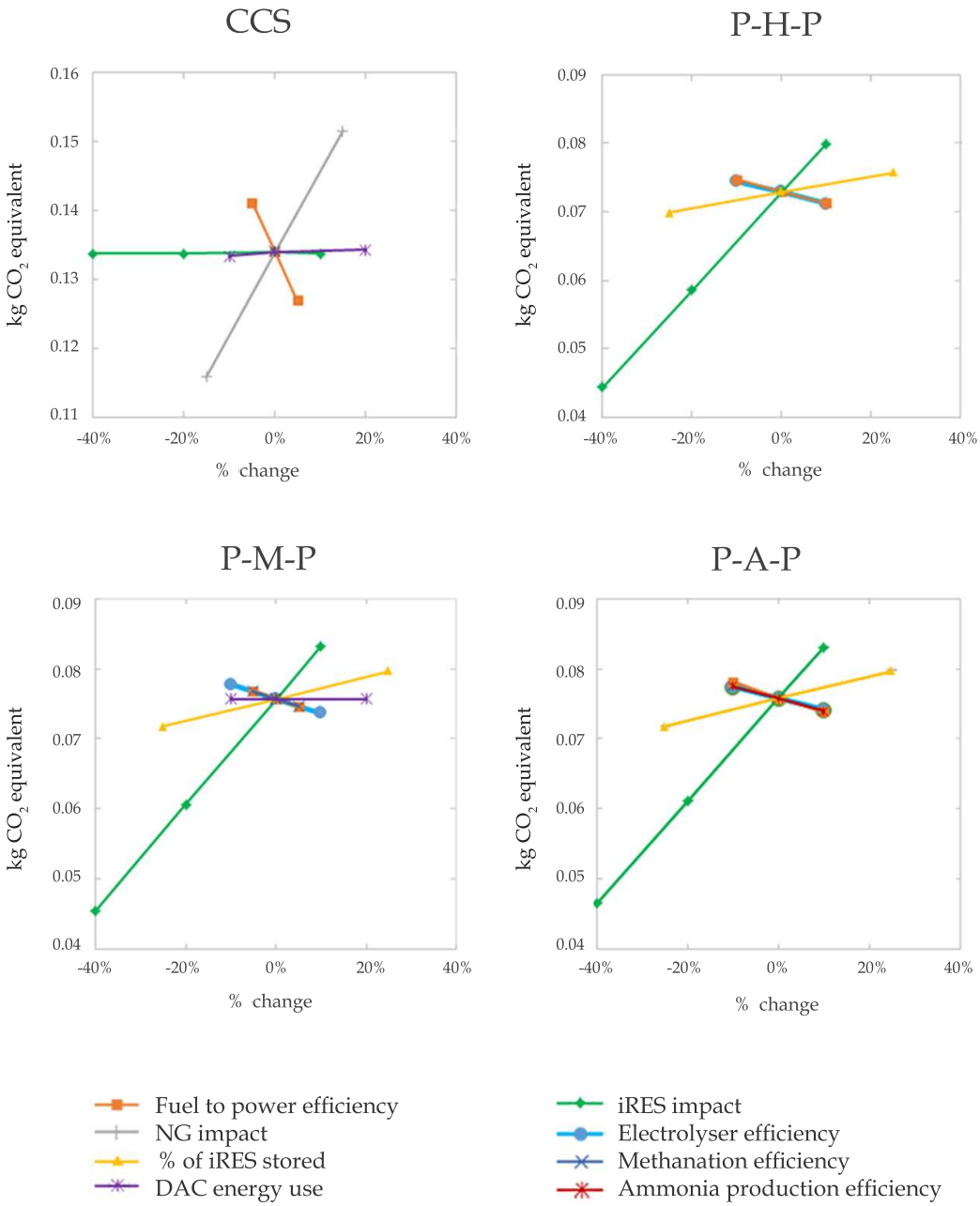

FIGURE 11 | Sensitivity analysis of climate change impact for the CCS, P-H-P, P-M-P, and P-A-P systems to several system parameters.

Combustion of Ammonia

One further uncertainty that was highlighted in the results is the large scale combustion of ammonia for energy purposes (see Section Breakdown by Key Processes). This is a concept recently received much attention but not yet extensively researched (Institute for Sustainable Process Technology, 2017; Yapicioglu and Dincer, 2019). Many key technical and environmental performances of ammonia combustion such as the direct emissions of NO_x and unburned ammonia are still uncertain. Estimates for NO_x emissions in flue gas from ammonia combustion range from 20 to 2,300 ppm, depending on various parameters such as equivalence ratio's[1], inlet temperatures, fuel additives and combustion pressures (Nozari and Karabeyoğlu, 2015; Valera-Medina et al., 2018). We here chose a value of 300 ppm NO_x, six times higher than in a *natural gas*

[1]Equivalence ratio: the ratio of fuel vs. oxidizer. An equivalence ratio > 1 means that the blend has more fuel than can be burned based on the stoichiometric ratio.

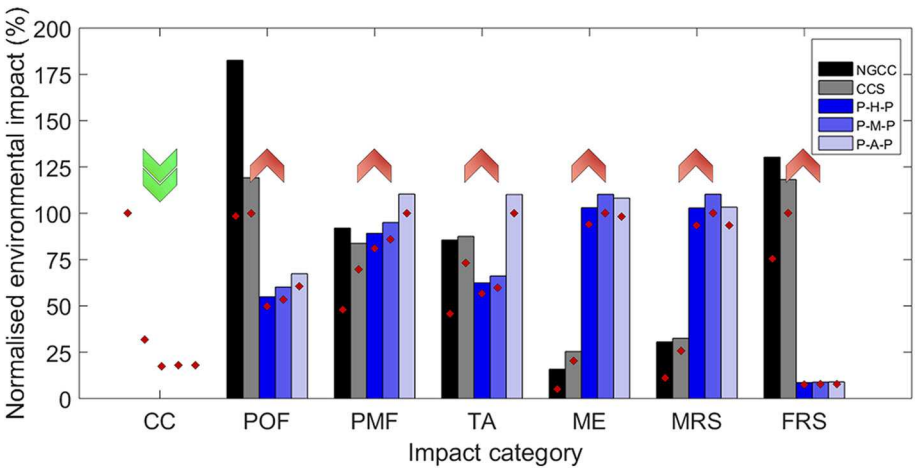

FIGURE 12 | Change in environmental impact per kWh dispatchable electricity if DAC is also used to fully negate the GHG emissions of background processes. The bars show the increased environmental impacts of the zero GHG emission systems; the diamonds give original values from the net-zero-direct-CO_2-emissions systems in **Figure 8**. Arrows show whether there is an increase or decrease of the impact compared to the case where only the foreground emissions were abated. A value of 100% represents the system with the highest environmental impact on that impact category.

combined cycle, because it is expected that the different burning characteristics of ammonia will always lead to relatively high NO_x emissions (Nozari and Karabeyoğlu, 2015). For the amount of unburned ammonia we chose 30ppm, which is based on research from Kobayashi et al. (2019) and Kurata et al. (2019). Many studies about ammonia combustion do not report on unburned ammonia emissions at all (Valera-Medina et al. and Nozari et al.).

Background Inventory for Future Production Systems

This paper analyzed future energy supply systems and used predictions of future electricity demand, renewable electricity supply and technological parameters. However, the database used for the background inventory, EcoInvent database version 3.5, is based on the current average technology level The impacts from the background inventories are expected to reduce in the future on the path of our energy transition toward more sustainable resources. The CO_2 emissions associated with PV panel production and natural gas supply will hopefully change for the better as we move to a low carbon world. To analyze a future energy system by using dynamic projections of life cycle inventory data is outside the scope of this research.

Net-Zero Direct CO_2 Emissions vs. Net-Zero Life Cycle Greenhouse Gas Emissions

In the above analysis, we looked at mitigating the direct CO_2 emissions of electricity production and supply systems. However, we also showed that even in the case of net-zero-direct-CO_2-emissions, there were still substantial GHG emissions in the background of our systems. **Figure 10** also shows that many of these background emissions stem from outside the region of study (in this case Central West Europe). This raises the question of what net-zero really means, which also relates to the question of stewardship. That is, if a country or region wants to reach net-zero at a given moment in time, should it then also compensate for indirect emissions, and should it also compensate for emissions outside its own region, but attributable to its power supply system? Given the nature of this contribution, we will not speculate on the political or legal aspects of such questions, but we can show how the full value chain could be made climate neutral over its life cycle, and what this implies for other environmental impacts.

To completely rid our electricity production systems of all indirect CO_2-eq. emissions, an immense amount of supply chain improvements would need to be realized. In the CCS system, it would be necessary to completely eliminate methane losses during transport and natural gas production and use renewable electricity to power compression stations in both the EU as Russia. In the P-X-P systems, as materials are increasingly imported from outside of the EU, mainly China, the effort of the replacement of coal power plants with wind and PV in China becomes an essential measure in order to achieve a true net zero-emission of our electricity system. However, it would be difficult for the EU to implement or enforce such energy transition strategy outside the EU (other than through global multilateral agreements following the Paris Agreement).

Alternatively, a country or region could compensate for the emissions of its energy system outside its geographic boundaries. In the spirit of this work, one option would be to use DAC to negate all CO_2-eq. emissions left in the system. Naturally, the other environmental impacts will then further increase, because the additional DAC also needs additional energy (thus PV and wind). **Figure 12** shows the increase in environmental impacts if we increase DAC and CO_2 storage to have a system with zero life cycle GHG emissions. The energy required for DAC was expected to come from within the system itself. The increase of other environmental impacts for the unabated NGCC system is the highest among the five systems studied, with an average increase of 112% (**Figure 11**). This is due to the fact that it had the highest GHG emissions in the original system, so a higher DAC capacity is needed to negate the remaining emissions. The other impacts

of the CCS system increase on average by 21% and the P-X-P systems with 11% (meaning there is less environmental burden of making the P-X-P systems net-zero GHG over their life cycle).

There is a positive feedback loop when the GHG impact of the renewable supply is decreased, because reducing emissions in our system leads to cleaner electricity which improves our system again. This loop is taken into account and thus less direct air capture is needed compared with the situation were the background emissions of the electricity supply would have been kept stable. Battling climate change through the capture of CO_2 with DAC will be technologically possible. However, implementing it on the scale that would be necessary to completely negate the remaining GHG emissions will require a massive deployment of this technology and introduce an increase in other environmental impact categories. In the P-X-P systems this increase on non-climate change categories is up to 11%, whereas for the CCS system impact increases by 21%.

CONCLUSIONS

This study addressed the system design, sizing and life-cycle assessment of three power-to-X-to-power systems for chemical energy storage of intermitted renewable electricity. Hydrogen, methane and ammonia were assessed as potential energy carriers and all systems were designed to adhere to the net-zero-direct-CO_2-emission constraint. The LCA comparison between the P-X-P systems and two reference CCS systems (one fully abated, one unabated) on seven impact categories showed there was not a single clear winner as several trade-offs were found between them. Net-zero-direct-CO_2 P-X-P systems result in a climate change impact that is up to 50% lower than the fully abated NGCC system and has lower impacts on both photochemical ozone formation and fossil resource scarcity. The fully abated NGCC system outperformed the P-X-P systems on marine eutrophication and mineral resource scarcity where their results were comparable for particulate matter formation. Among the three P-X-P systems assessed the hydrogen system has the lowest environmental impact in all categories due to its higher round trip efficiency.

This publication has focused on the environmental impacts of net-zero CO_2 energy systems. A full economic performance was not undertaken. The system design, however, indicates that the very low capacity factors for both electrolyser and the re-electrification modules are reason to believe that the economic attractiveness of the P-X-P systems as such might be limited. The same hurdle was found in the research by Götz et al. (2016), where it is shown that synthetic natural gas cannot be expected to compete with natural gas prices even when the electricity cost is 0 ct/kWh. In real power systems the P-X-P systems might be able to collaborate with different systems or modes of operation, thereby increasing the capacity factor and economics. An example of this could be cross-sector coupling of the energy and chemicals sector through methanol, ammonia, or another synthetically produced molecule.

Nevertheless, a system without climate change impact in its entire life cycle, including the background, was proposed and assessed. This was achieved by capturing an equal amount of CO_2 from the atmosphere in order to cancel out any background emissions that are still present in the net-zero-*direct*-CO_2 systems. If the systems are equipped with enough direct air capture to do this, it would logically lead to an increase in the other impact categories. This demonstrates the importance of using multiple indicators in (environmental) decision making, as it can show drawbacks of technologies otherwise overlooked. In this research we show that P-X-P systems can have a place in future zero carbon energy systems, but that it also has its trade-offs and hurdles to overcome. These trade-offs are only visible if decision making is not only focused on CO_2 emissions but also takes other impacts into account.

DATA AVAILABILITY STATEMENT

All datasets generated for this study are included in the article/**Supplementary Material**.

AUTHOR CONTRIBUTIONS

The authors together conceived the original idea. JW undertook the quantitative analysis under guidance of MS and LS. All authors contributed to authoring the manuscript and agree to its final content.

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SUPPLEMENTARY MATERIAL

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/fenrg.2020.00104/full#supplementary-material

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frontiers in Energy Research

REVIEW
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German Energy and Decarbonization Scenarios: "Blind Spots" With Respect to Biomass-Based Carbon Removal Options

Alena Hahn[1]*, *Nora Szarka*[1] and *Daniela Thrän*[1,2,3]*

[1] Bioenergy Systems Department, DBFZ Deutsches Biomasseforschungszentrum (German Biomass Research Centre), Leipzig, Germany, [2] Department of Bioenergy, Helmholtz Centre for Environmental Research – UFZ, Leipzig, Germany, [3] Chair Bioenergy Systems, Institute for Infrastructure and Resources Management, Leipzig University, Leipzig, Germany

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International Energy Agency, France

***Correspondence:**
Alena Hahn
alena.hahn@dbfz.de
Daniela Thrän
daniela.thraen@ufz.de

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In 2019, the German government agreed on a Climate Protection Program intended to deliver its 2030 climate targets. Concrete measures, such as a carbon price, will be put in place as early as 2021. But how to plan beyond 2030? Scenarios can be powerful tools to envision the world in 20, 30, or 50 years, to describe pathways toward different visions of the future, and ultimately to investigate technology portfolios and policy options against their performance toward the achievement of a decarbonized future. This is why scenarios are especially popular with energy and climate scholars. In particular, scenarios with biomass-based carbon removal options (BCO_2) can help to highlight how we may reach a net negative emission world. Hence, in this study, 66 energy and decarbonization scenario studies are systematically reviewed for Germany from the years 2002 to 2019 to assess how inclusive they are with regard to BCO_2 concepts. The portfolio of BCO_2 concepts within those scenarios is studied over time and a qualitative analysis of the scenario documentation is performed to identify the rationales for their inclusion or exclusion. The results indicate "blind spots" of the scenarios with regard to bioeconomy aspects, as biomass for material use is only sparsely covered. Likewise, only about 10% of the studies provide a framework for land use changes and corresponding emission accounting to adequately represent biomass-based negative emission technologies (NETs) in their assessments. The analysis for carbon capture and storage (CCS) further reveals the necessity of revisiting the public acceptance argument which has previously served so far for many studies as the ultimate, though not well-grounded deal-breaker. Based on the detected gaps and shortcomings in the current German scenario landscape, recommendations for a more transparent and holistic representation of BCO_2 in the scenario framework are given.

Keywords: energy scenarios, Germany, negative emission technology (NET), Carbon Dioxide Removal (CDR), Bioenergy with Carbon Capture and Storage (BECCS), biogenic carbon, carbon capture and utilization (CCU), power-to-gas (PtG)

INTRODUCTION

With the Paris Agreement of 2015, the international community of states has set itself stringent targets for the reduction of greenhouse gas (GHG) emissions. However, the agreement does not prescribe any specific measures—this is at the discretion of the respective states. In Germany, the federal government adopted the Climate Action Plan 2050 in November 2016, specifying its implementation strategy on national level: a long-term goal of GHG neutrality by 2050 and an intermediate target of at least 55 percent GHG emission reduction compared to 1990 by 2030. With its Climate Protection Program published in 2019, the German government further reaffirmed this ambition by outlining strategic policy ideas to reach the 2030 climate targets.

Energy and decarbonization scenarios can help to investigate technology options and regulatory measures that can make significant contributions to the achievement of these targets. Although scenarios are not projections or predictions of the future, they are internally coherent narratives that describe pathways toward different visions of the future. Due to their explorative character, energy and decarbonization scenarios should be as technology-open as possible, incorporating innovative concepts and emerging technologies.

A set of such technologies is Carbon Dioxide Removal (CDR), i.e., technologies and processes that absorb CO_2 from the atmosphere. If the carbon thus obtained is not used but sequestered, then this concept is referred to as Negative Emission Technologies (NETs) due to their ability of removing more CO_2 from the atmosphere over their entire lifecycle than emitting CO_2, thus being net negative in their emissions balance. The most recent special report of the Intergovernmental Panel on Climate Change (IPCC) on the impacts of global warming of 1.5°C above pre-industrial levels (SR1.5) acknowledges the important role of NETs for stabilizing atmospheric CO_2 concentrations (IPCC., 2018). However, most Integrated Assessment Models (IAMs) that submitted scenarios for consideration in the SR1.5 database are limited in their analysis to two NETs, namely Bioenergy with Carbon Capture and Storage (BECCS)[1] and afforestation/reforestation. In fact, 9 out of 10 IAMs that successfully submitted scenarios explicitly model BECCS; 7 out of 10 consider afforestation/reforestation. In contrast, only two modeling frameworks directly address both Direct Air Capture and Storage (DACS) and Soil Carbon Sequestration (SCS). Restoration of wetlands and biochar are—if at all—only assessed implicitly and in an exogenous manner, i.e., they are not represented in any of these models but can be explored through comparison of multiple alternative scenarios. Similarly, ocean fertilization and enhanced weathering are not represented in any IAM reported by Forster et al. (2018).

To better understand potential challenges and synergies of biomass-based NETs, various scholars conducted more detailed analyses on subsets of NETs. In this regard, "biomass-based negative emissions" (Heck et al., 2018) or similar concepts such as "plant-based CDR" (Lenton, 2014a), "biomass-based CDR" (Turner et al., 2018), "land-based biological CO_2 removal" (Lenton, 2014b), and also "terrestrial CDR (tCDR)" (Boysen et al., 2017) have been proposed for more refined assessments focusing mainly on BECCS, biochar, standing biomass, and to a lesser extent on biomass burial. Similarly, "natural climate solutions" (Griscom et al., 2017; Fargione et al., 2018) were assessed which consist in a set of 20 improved land management actions that increase the carbon sink function of forests, wetlands, grasslands, and agricultural lands. All these concepts compete for available land and available biomass. In fact, pathways for limiting global warming to 1.5°C might require the area of up to 12 million km^2–representing the size of the entire European continent—to increase forest coverage in 2050 compared to 2010 levels (IPCC, 2019).

However, biomass-based NETs are not the only contenders for land and biomass. Food production, renewable energy provision, and some industries that rely on biomaterials also compete for these scarce resources. Therefore, a holistic approach is needed to address all biomass-based CO_2 emissions reduction options (hereafter referred to as BCO_2 concepts) that either (a) rely on the energetic or material use of biomass, (b) substitute fossil carbon sources and products through biogenic CO_2, or (c) provide negative emissions based on biomass and land resources (**Figure 1**). Capturing the range of these concepts as comprehensively as possible in energy and decarbonization scenarios serves two main purposes: on the one hand, to assess their CO_2 reduction and negative emissions potentials, and on the other hand, to identify possible competition for land and biomass use.

Taking Germany as case study, a structured review is carried out for 66 energy and decarbonization scenario studies from the years 2002 to 2019 to assess how inclusive they are with regard to BCO_2 concepts. The evolution of the portfolio of BCO_2 concepts within those scenarios is studied over time and a qualitative analysis of the scenario documentations is performed to identify the rationales for their (non-)inclusion. Furthermore, gaps in the scenario coverage of BCO_2 options are addressed.

METHODOLOGY

In times of rapidly expanding scientific knowledge, the systematic review of published research serves multiple purposes at once: identifying and synthesizing the vast amount of studies to assess the state of science in a given field of knowledge and steer further progress in that field. By combining the results of relevant studies in a structured and transparent manner, this can further enhance the credibility of scientific assessments in general and allow for a more robust communication toward policymakers (Petticrew and McCartney, 2011; Minx et al., 2017).

In the more specific case of reviewing energy scenario studies, a systematic review can provide insights into the design of the future energy mix, CO_2 mitigation options and driving factors for change. In addition, comparatively assessing scenario

[1]If not explicitly stated otherwise, BECCS is understood in this paper as all kinds of bioenergy production combined with carbon capture and storage. It therefore encompasses dedicated bioenergy plants, biomass co-firing plants, biofuel production, and industrial uses of biomass, for example in the iron and steel industry.

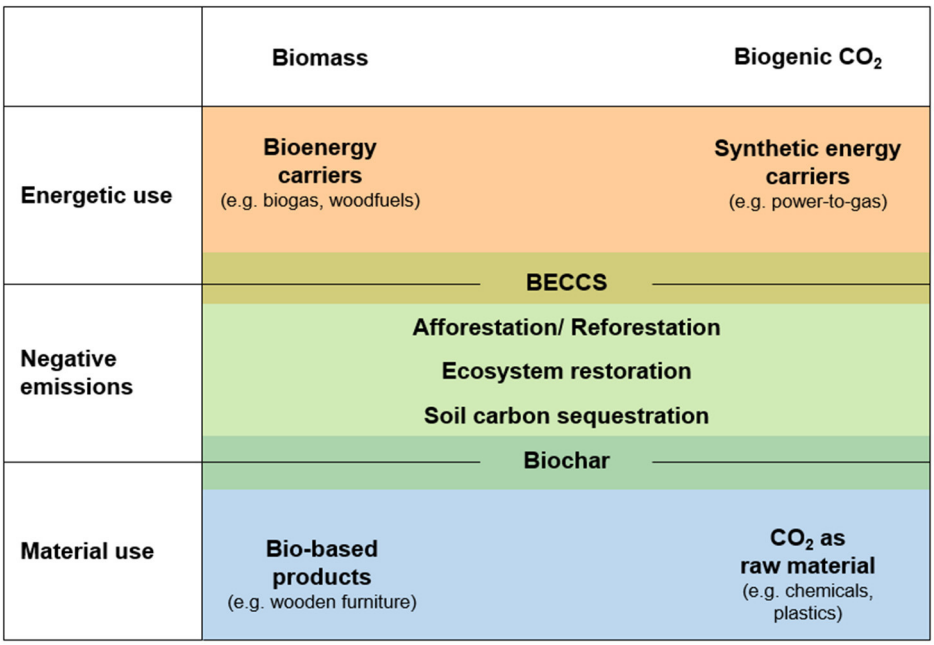

FIGURE 1 | Classification of biomass-based carbon removal options (BCO_2).

studies, their assumptions, and results enables highlighting system interdependences and evaluating different policy options. In fact, energy system and climate scholars regularly use scenario instruments to investigate possible future developments. By formulating fundamentally different assumptions for the future, scenarios can create awareness for uncertainties, opportunities, and risks associated with each of these possible futures.

For this study, a comprehensive list of German energy and decarbonization scenarios was established based on (a) study compilations of previous meta-analyses (Kronenberg et al., 2011; Haller et al., 2016; Peter et al., 2017; Szarka et al., 2017; Runkel, 2018; Samadi et al., 2019), (b) studies identified via scientific journals using Scopus and Web of Science, and (c) gray literature found via Google. Additionally, the reference lists of all identified documents were screened for collecting further scenario studies. The following word combinations were used as search terms, in both English and German: German* AND scenario* AND energy and climate change related terms ("energy system," "energy transition," "decarbonization," "climate change mitigation") AND the time horizons 2020–2100 in 5 year increments. Cutoff date for considering studies was November 2019, i.e., when performing the literature research. To qualify for the assessment, all scenario studies had to fulfill the following criteria:

- Explicit focus on either the energy transition ("Energiewende"), a 100% renewable energy system, or ambitious decarbonization and GHG reduction targets;
- Coverage of at least two of the three energy sectors, i.e., power, heat, and transport, thus excluding sector-specific studies;
- Quantification and/or modeling of the scenarios, therefore excluding Del phi surveys (BDEW, 2016) and expert elicitation of future trends and policy measures (BMU, 2016; Renn, 2017) for comparability reasons.

A catalog of the identified studies is shown in **Table 1** with key information on their respective year of publication, source of funding, investigated scenarios and time horizon.

For the analysis, all scenario-based studies were screened for biomass-related carbon removal options as conceptualized in **Figure 1**. Both qualitative and quantitative mentions of all BCO_2 concepts were gathered. Information was collected on whether they were (a) mentioned at all, (b) excluded on purpose, (c) considered within the scenario narratives, and/or (d) quantitatively assessed as part of the scenario modeling.

Additionally, with respect to the energetic and material use of biomass, all studies were screened for their biomass potentials, sectoral coverage of biomass use, imports, and sustainability considerations. For the energetic and material use of biogenic CO_2, data was systematically gathered on CO_2 supply volumes from both biogenic and other sources, as well as on CO_2 utilization pathways in the energy and industrial sectors. The BCO_2-focused analysis extends to non-biogenic CO_2 sources as the latter ones can be used interchangeably in subsequent CO_2 utilization applications. Furthermore, alongside information on BECCS, data was also gathered on fossil carbon capture and storage (CCS), industrial CCS and direct air capture with carbon storage (DACCS) as their concepts are similar to BECCS in terms of infrastructure requirements and geological storage. This was further combined with the collection of arguments within the studies for/against the use of CCS. Finally, references

TABLE 1 | Overview and characteristics of the reviewed scenario studies.

Funding bodies	Year of publication	Title	Original language	Number of scenarios	Time horizon	References
Ministries, Governmental Agencies						
Bundestag	2002	Final report of the enquete commission on sustainable energy supply	DE	4	2050	Bundestag, 2002
BMU	2004	Ecologically optimized extension of renewable energy utilization in Germany	DE	5	2050	BMU, 2004
	2008–2011	Long-term scenarios for the deployment of renewable energies	DE	16	2020–2050	BMU, 2008, 2009a, 2010, 2012
	2009–2017	Projection reports	DE	2	2020–2035	BMU, 2009b, 2011, 2013, 2015b, 2017
	2014–2015	Climate protection scenario 2050	DE	4	2050	BMU, 2014, 2015a
	2019	Impact assessment for the 2030 sectoral targets	DE	3	2030	BMU, 2019
BMWi	2005	Energy report IV	DE, EN	1	2030	BMWi, 2005
	2007–2011	Energy scenarios	DE	14	2020	BMWi, 2007, 2010b, 2011
	2010–2014	Development of energy markets by 2030	DE	5	2030	BMWi, 2010a, 2014
	2015	Interaction of renewable power, heat and mobility	DE	1	2050	BMWi, 2015
	2018	Long-term scenarios for the energy system transformation in Germany	DE	12	2050	BMWi, 2018
BMBF	2019	Pathways for Germany's Low-Carbon Energy Transformation Toward 2050	EN	3	2050	Bartholdsen et al., 2019
IRENA	2015	REmap 2030. Renewable Energy Prospects: Germany	EN	2	2030	IRENA, 2015
dena	2018	Integrated energy transition. Impulses to shape the energy system up to 2050	DE	5	2050	dena, 2018
BfN	2018	Eco-friendly energy supply based on 100% renewable energies	DE	3	2050	BfN, 2018
UBA	2008–2018	Policy scenarios for climate protection	DE	7	2030–2035	UBA, 2008, 2009, 2013b, 2018
	2010	Energy target 2050. 100% renewable electricity supply	DE	1	2050	UBA, 2010
	2013	Modeling of a fully renewable electricity supply in 2050	DE	3	2050	UBA, 2013a
	2014	Germany in 2050—a greenhouse gas-neutral country	DE, EN	1	2050	UBA, 2014
	2019	A resource efficient pathway toward a greenhouse gas neutral Germany	DE, EN	1	2050	UBA, 2019a
	2019	RESCUE—resource-efficient pathways to greenhouse-gas-neutrality	DE	6	2050	UBA, 2019b
Industry, Companies						
BDI et al.	2007	Energy master plan 2030	DE	3	2030	BDI, 2007
BDI	2013	Trend study 2030+. BDI's energy competence initiative	DE	4	2050	BDI, 2013
	2018	Climate Paths for Germany	DE	5	2050	BDI, 2018
EnBW et al.	2009	Energy future 2050	DE	3	2050	EnBW, 2009
BEE	2014–2018	German energy supply scenarios	DE	17	2060	BEE, 2014a,b, 2015, 2016, 2017, 2018
50Hertz	2016	Energy transition outlook 2035	DE	5	2035	50Hertz, 2016
ExxonMobil	2011–2018	German energy market outlook	DE	1	2030–2040	ExxonMobil, 2011, 2012, 2016, 2018
Shell	2017	Energy Scenarios Germany	DE, EN	2	2050	Shell, 2017
Gelsenwasser et al.	2017	The energy market in 2030 and 2050	DE, EN	2	2050	Gelsenwasser, 2017

(Continued)

TABLE 1 | Continued

Funding bodies	Year of publication	Title	Original language	Number of scenarios	Time horizon	References
Ministries, Governmental Agencies						
WWF	2009	Blueprint Germany—a strategy for a climate-safe 2050	DE, EN	5	2050	WWF, 2009
SRU	2011	Pathways toward a 100% renewable electricity system	DE, EN	8	2050	SRU, 2011
Agora	2013	Cost-optimal expansion of renewables in Germany	DE, EN	3	2033	Agora, 2013
BUND	2015	Fundamental concepts for the energy transition 2050	DE	1	o.J.	BUND, 2015
Greenpeace	2007–2015	Climate protection plan for Germany	DE	3	2020–2050	Greenpeace, 2007, 2010, 2015
Greenpeace	2018	How can Germany still achieve its climate target? Energy scenario 2020	DE	2	2020	Greenpeace, 2018
Research Institutes						
FVEE	2010	Energy concept 2050	DE, EN	1	2050	FVEE, 2010
PIK	2012	Ambitious mitigation scenarios for Germany. A participatory approach	EN	3	2050	Schmid and Knopf, 2012
Fraunhofer ISE	2012	100% renewable energy for power and heat in Germany	DE	3	2050	Fraunhofer ISE, 2012
	2013	Energy system Germany 2050	DE	1	2050	Fraunhofer ISE, 2013
	2015	Pathways for Transforming the German Energy System by 2050	DE, EN	9	2050	Fraunhofer ISE, 2015
Hansen et al.	2019	Full energy system transition toward 100% renewable energy in Germany in 2050	EN	8	2050	Hansen et al., 2019

Original language of the scenario studies in German (DE) and/or English (EN). Abbreviations of funding bodies: BMU, Federal Ministry for the Environment; BMWi, Federal Ministry for Economic Affairs and Energy; BMBF, Federal Ministry of Education and Research; BfN, Federal Agency for Nature Conservation; IRENA, International Renewable Energy Agency; dena, German Energy Agency; BfN, German Federal Agency for Nature Conservation; UBA, German Environment Agency; BDI, Federation of German Industries; BEE, German Renewable Energy Federation; WWF, World Wide Fund for Nature; SRU, Advisory Council on the Environment; BUND, Friends of the Earth Germany; FVEE, Renewable Energy Research Association; PIK, Potsdam Institute for Climate Impact Research; Fraunhofer ISE, Fraunhofer Institute for Solar Energy Systems.

to other biomass-based NETs (i.e., afforestation/reforestation, biochar, soil carbon sequestration, and ecosystem restoration) were collected.

RESULTS AND DISCUSSION

Publication Trends in German Energy and Decarbonization Scenarios

After the thorough scenario study collection and selection according to the criteria set out in the previous section, 66 relevant studies were identified, published in the years from 2002 to 2019 and containing a total of 189 scenarios. Interest in scenario studies started to increase notably around 2010, doubling in numbers until 2015 and tripling until today (**Figure 2**). Given the studies' time horizons, three different waves of studies can be identified: Those addressing the year 2020 leveled out after 2010. A similar dynamic can be observed right now for scenarios running up to 2030. This confirms that scenarios serve long-term planning purposes, with more than 10–15 years lead time. The third observable pattern is a rapid increase of studies addressing mid-century with scenarios running up to 2050. This is also in line with the time horizons of most global assessments, including the IPCC SR1.5 report that highlights that carbon neutrality should be achieved around this time for a 1.5°C consistent pathway (IPCC., 2018).

When looking at the source of funding for the 66 analyzed studies, the results reveal that the majority of funding bodies are ministries or governmental agencies, representing 52% of the study sample. An additional 26% comes from industry bodies and companies. Non-governmental organizations (NGOs), think tanks and foundations funded around 12% of the studies and research institutions another 11%. The large share of funding from the political realm and industry confirms their interest in scenarios as a tool for assessing long-term policy options and measures. Therefore, the scenarios should be as technology-open as possible and not confined to a specific sub-set of technologies. As part of a broader climate change mitigation portfolio, BCO_2 concepts should be assessed from a systems and scenario perspective first, before ultimately deciding on desired futures and technologies.

Unbalanced Representation of Energetic and Material Use of Biomass

Bioenergy is contributing to fossil fuel replacement, potentially achieving zero to near-zero emissions in the areas of its application. This is due to its carbon intake during plant

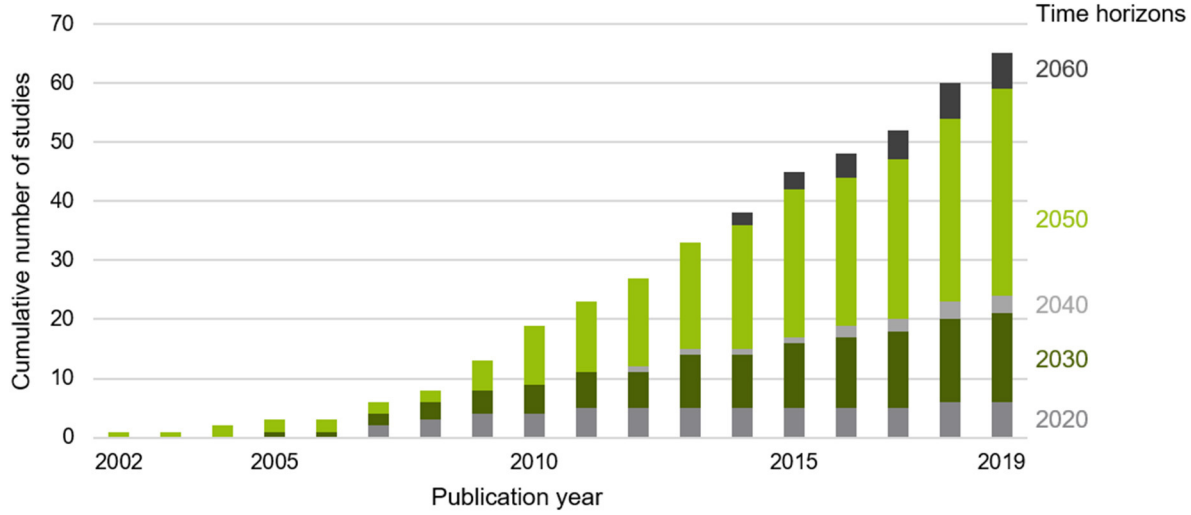

FIGURE 2 | Publication dynamics of German scenario studies for different time horizons.

growth i.e., CO_2 capture from the atmosphere through photosynthesis. In contrast, biomass from a material use perspective contributes to emission reductions by substituting either fossil fuel-based products (e.g., cotton products instead of polyester) or otherwise energy-intensive products (e.g., wooden building materials instead of concrete or steel). In both cases, bioenergy's potential to offset emissions compared to fossil fuels has to be determined via a full life-cycle analysis (LCA) (Cherubini and Strømman, 2011).

Regarding the scenario coverage of biomass for energetic and material use, all 66 studies deal to some extent with bioenergy in their scenarios. As such, it is the only BCO_2 category that is addressed—and most often also quantified—in terms of GHG emission reductions within all the scenarios. In contrast, the consideration of non-energy related biomass use is scarce: only 13 out of the 66 studies mention at least once the material use dimension. This picture of unbalanced biomass use representation in the scenarios is further confirmed when assessing the biomass potentials allocated to energetic and material purposes.

With respect to domestic bioenergy potentials, only every third study ($n = 24$) provides data, resulting in a range of 216–2,300 PJ (**Figure 3**). This discrepancy by the factor 10 is due to the fact that there is no common methodology for determining either the underlying biomass potential or its attribution to the energy sector. For instance, dating back to the year 2004, a scenario study financed by the Federal Ministry for the Environment (BMU) assessed from a nature conservation point-of-view the land availability for bioenergy crops as well as various biomass waste and residue streams, resulting in a sustainable bioenergy potential of 1,440 PJ (BMU, 2004). Another eight scenario studies subsequently used this publication as basis for their modeling. However, despite this joint reference point, the stated potentials differ due to further assumptions made by the studies individually. On the lower end of the spectrum, studies only rely on biogenic waste and residues as bioenergy carriers, explicitly excluding dedicated energy crops due to sustainability concerns. Taking an even more conservative approach, a study commissioned by the German Environment Agency (UBA) study further divides the biogenic waste and residues by setting aside solid ones, such as straw and scrap wood, for material use, thus reducing the available biomass for energetic purposes even further (UBA, 2010). In contrast, the upper end of the spectrum consists of studies that do not provide any further information as to how their bioenergy potential is composed.

Detailed information about the material use of biomass is even less abundant. Besides the already cited UBA study, only five other studies reserve some biomass for non-energetic purposes, either by limiting the available land for bioenergy production to account for the material supply (BMU, 2015a; BMWi, 2018), by using industrial waste streams directly for industrial products and processes (UBA, 2019b), or by not fully exploiting the technical bioenergy potential, thus leaving a certain share to material use options (BMWi, 2014, 2015).

Biomass imports can extend the available resource base, alleviating to some extent the competition for limited biomass resources. However, the question of imports causes a clear divide within the scenario studies: without stating explicit concerns, a group of eight studies allows imports to supplement the domestic resource availability, in some cases to an extent of up to 900 PJ (BMU, 2014). In contrast, another 16 studies explicitly exclude biomass imports from their scope to avoid direct and/or indirect land use changes abroad that are likely to aggravate food security issues in emerging and developing countries (BMU, 2010, 2012). In addition, they argue that countries with climate mitigation efforts similar to the ones in Germany will tap their own biomass resources, so that relying on imports is not a sustained option in the long term (BMU, 2012).

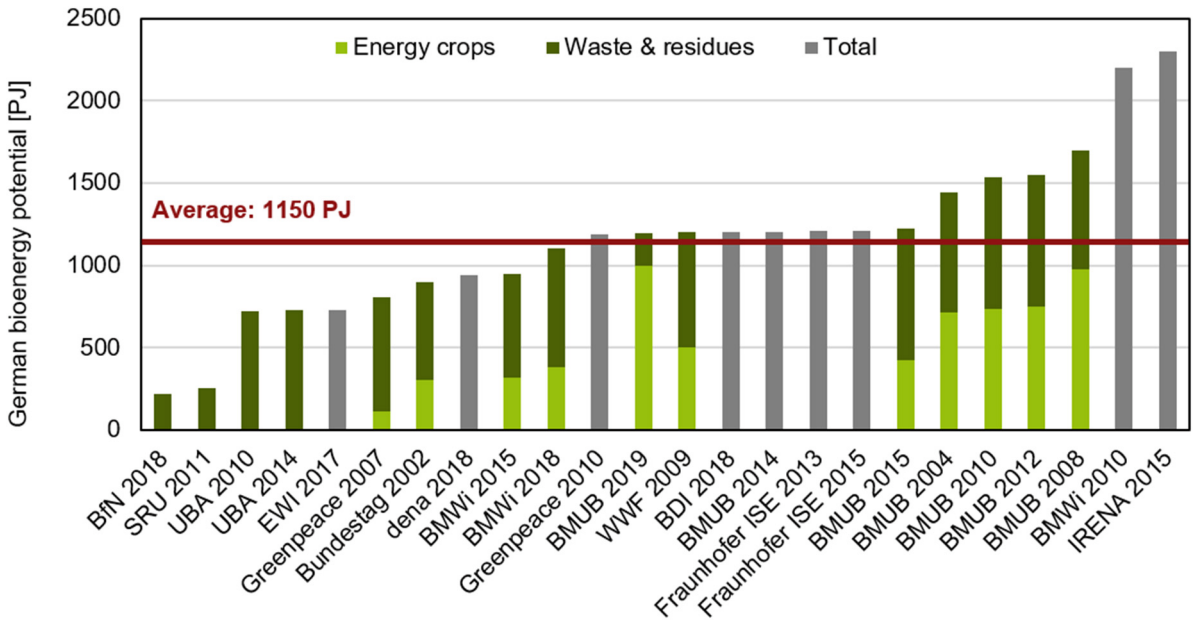

FIGURE 3 | Range of domestic bioenergy potentials as indicated by German scenario studies.

Challenges in Matching Biogenic and Industrial CO_2 Supply and Demand

Similar to biomass that faces the challenge of reconciling various demands with the existing, limited potential, biogenic CO_2 is also subject to supply and demand dynamics. On the supply side, biogas upgrading, bioethanol plants, and biomass-to-liquid processes yield relatively pure CO_2 side-streams. CO_2 capture is also possible in combination with biomass gasification or combustion but comes with a higher energy and efficiency penalty due to a lower CO_2 concentration in their exhaust gases. Further adding to the equation, CO_2 supply is not only possible through biogenic sources but also captured from fossil-based power stations, industrial plants, and/or directly from the air. However, fossil CO_2 sources will not be further discussed in this paper, given that all analyzed studies that deal with carbon capture and utilization (CCU) options exclude fossil sources for CO_2 supply. Besides the already mentioned energy penalties, the main reason for this exclusion is linked to carbon accounting issues, as fossil-based CCU only delays net CO_2 being released into the atmosphere. On the demand side, CO_2 can be an input for various CCU pathways that are further described below.

With regard to potential biogenic CO_2 supply volumes, only few scenario studies provide data for the German case. For 2050, estimates suggest an availability of 5.3–11 Mt CO_2 from biogas upgrading plants (BMU, 2012; UBA, 2014). Biofuel production may lead to 36 Mt CO_2 as side product (WWF, 2009). Other conservative figures indicate a maximum potential of 15–25 Mt CO_2 from biogas upgrading, bioethanol production, and stationary bioenergy use combined (UBA, 2014; BMWi, 2018). Based on these studies, the theoretical availability of biogenic CO_2 will likely range between 15 and 36 Mt. Assuming 90% CO_2 capture rates from bioenergy plants (WWF, 2009), the technical availability is slightly lower. In addition, due to the remote and dispersed location of some of these plants, only up to 70% of this technical potential might be achievable (BMU, 2012). While these figures give a first appraisal of future biogenic CO_2 availability, data is sparse and related assumptions are either not stated at all or not in a transparent manner. Therefore, a robust evaluation and comparison of the biogenic CO_2 sources and supply volumes cannot be performed. For instance, biogenic CO_2 supply is heavily dependent on the assumed biomass potential as well as the biomass allocation within the energy sector. When prioritized as fuel for mobile consumption in the transport sector, a CO_2 fraction can be recovered in the biofuel production but not in its end-use application.

Industrial point sources are an alternative CO_2 source. In contrast to biogenic CO_2, the captured CO_2 from industrial processes is not GHG neutral. However, if CO_2 emissions are inherent to a given process and therefore unavoidable, for instance in the limestone calcination process, capturing this CO_2 for subsequent use or storage is still the best option for climate change mitigation. In integrated steel mills, CO_2 emissions mainly occur from iron production in the blast furnace, but also in the coke production step as well as in the sinter plant when preparing the iron ore. For 2050, conservative estimates suggest an availability of 13.8 Mt CO_2 from industrial processes, notably but not exclusively within lime and cement production (UBA, 2014). Another study indicates that steel production alone could deliver 31 Mt CO_2 in Germany (BMU, 2012). The highest estimate of 93 Mt CO_2 from industrial point sources extends the scope to CO_2 capture in steel, ammonia, and cement production, as well as refineries and waste incineration (BDI, 2018). As these ballpark figures show, the scope of industries considered for carbon capture strongly influences the potential

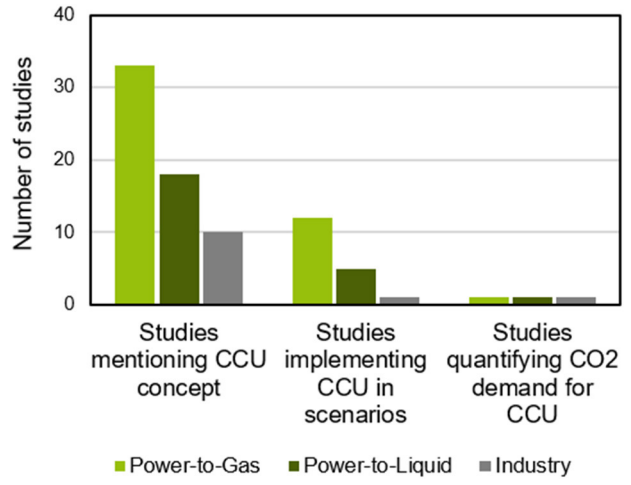

FIGURE 4 | Energy and material related CCU applications in German scenarios.

for industrial CO_2 supply. In addition, depending on alternative decarbonization options for the industry sector, the residual emissions and thus the capture volume might differ. According to the official German emission reporting to UNFCCC, CO_2 emissions of the entire industry sector amounted to 181 Mt CO_2 in 2017, out of which 56 Mt CO_2 were caused by the iron and steel industry (UBA, 2019b). However, it has to be noted that these official numbers represent both process and energy-related CO_2 emissions and can therefore not be directly compared to the above mentioned scenario estimates on CO_2 capture from industrial processes. To avoid blast furnace emissions in the steel production, a hydrogen-based direct reduction plant and subsequent melting of the iron ore in an electric arc furnace could replace the blast furnace conversion route (UBA, 2019a). This would drastically reduce the emissions of the steel sector, thus also reducing the amount of CO_2 available for capture, utilization and/or storage. However, the CO_2 avoidance costs for this method amount to around € 490/t CO_2eq, which is significantly more expensive than CO_2 capture combined with either utilization or storage (BDI, 2018). Another uncertainty factor lies in the capture efficiency due to multiple emission streams in some industry sectors. Taking again the steel example, while the blast furnace is the biggest emitter, there are other emission sources in the steel production, namely the coke plant and the sinter plant (BDI, 2018), rendering the implementation of carbon capture more difficult and—with lower CO_2 concentrations in these plants—also more expensive, in both cost and energy use.

In contrast to limited biogenic and industrial CO_2 sources, direct air capture (DAC) can theoretically deliver an unlimited amount of CO_2 captured from the atmosphere. However, none of the studies considers this technology in their mitigation portfolios. The main reasons for excluding it from their assessment are prohibitively high costs and low efficiency rates due to high energy demand (UBA, 2014; BUND, 2015; dena, 2018), especially if renewables are not yet predominant in the energy mix. Nevertheless, DAC is seen as a long-term option in Germany when there is no more untapped potential from biogenic and industrial sources (BMWi, 2018). Interestingly, some studies suggest that direct air capture is more likely to be applied abroad. Assuming that countries with more favorable conditions for renewable energies, i.e., higher solar radiation and/or wind availability than in Germany, would produce synthetic fuels for international export, these countries would incur a considerable need for CO_2 to convert the hydrogen produced from renewable electricity to hydrocarbon fuels. With biogenic and/or industrial CO_2 sources not necessarily being co-located with the fuel production sites, these countries would rely on DAC to satisfy the CO_2 demand (UBA, 2014, 2019b; BDI, 2018).

The reference to synthetic hydrocarbon fuels leads to the question of CO_2 utilization options. CO_2 can be put to use for both energetic and material purposes. As such, CO_2, along with hydrogen, is a building block for platform chemicals, plastics, and synthetic hydrocarbon fuels. Since the production of hydrogen through water electrolysis requires large quantities of electricity, these CCU pathways are also labeled as Power-to-X, whereas X can stand for gas (PtG), liquid fuels (PtL), chemicals (PtC), or other applications. As **Figure 4** shows, none of these CO_2 utilization concepts are adequately represented within the German scenario studies. Industry CCU, i.e., using CO_2 as a feedstock for industrial processes and products (e.g., input for platform chemicals; use as refrigerant gas, solvent, dry ice etc.), is the least mentioned concept. Moreover, only three studies incorporate syngas-based CCU routes it into their assessments which allow to subsequently build-up all major platform chemicals (UBA, 2014, 2019a; dena, 2018). In the long-term, the potential for CO_2 utilization as feedstock in the industrial realm in Germany is estimated by one scenario study to be limited to 5 Mt per year in addition to its current use (dena, 2018). In contrast, the energetic use of CO_2 is better represented, with PtG being part of the scenario modeling in about 30% of the studies. However, this PtG—and to a lesser extent PtL—integration is not primarily motivated by the prospects of CO_2 utilization. In fact, only two studies explicitly indicate the amount of CO_2 needed, namely 27 Mt for synthetic methane production in one case (UBA, 2014) and 79 Mt for the production of methanol and dimethyl ether in another case (Hansen et al., 2019). Instead the focus with regard to PtG and PtL lies on their ability to (a) function as temporary storage of excess power from variable renewable energy sources, and (b) provide a renewable energy source for the otherwise difficult to decarbonize sectors, such as aviation and heavy duty trucks. The latter reason is also why various studies consider importing synthetic energy carriers, sometimes even up to 85–100% of the entire projected PtG or PtL consumption (BDI, 2018; BMU, 2019; UBA, 2019b). Shortcomings in CCU scenario modeling therefore are the lack of transparent assumptions and quantified data on CO_2 as major input sources for PtX, both from an energy and even more importantly a material use perspective. As a consequence, a matching of domestically available CO_2 supply with the potential CO_2 demand is not possible.

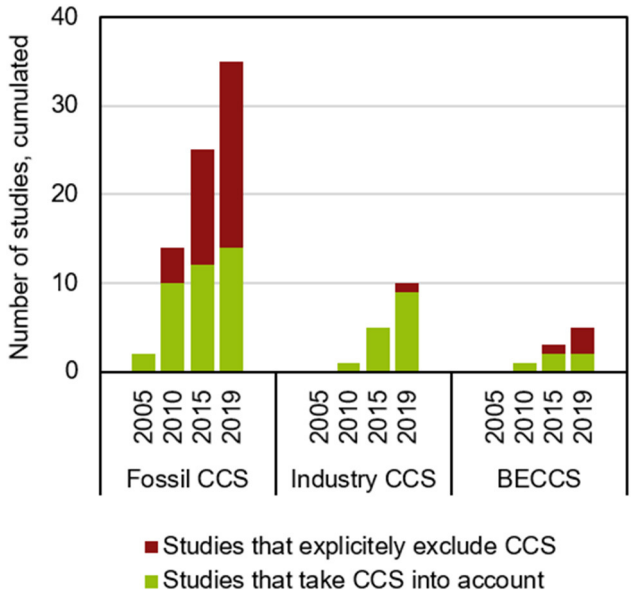

FIGURE 5 | The exclusion of fossil, industrial and biomass-based CCS in German scenario studies over time.

Costs vs. Public Acceptance: Rationales for and Against (BE)CCS

While BECCS is implemented in almost all IAMs and therefore well-represented in global IPCC scenarios (Forster et al., 2018), the results for the German scenario landscape are much different. **Figure 5** shows that BECCS was included in a scenario study for the first time around 2010. In this pioneering study, the modeling framework provided a CCS option for bioethanol and biodiesel production, leading to a scenario of capturing 32 Mt CO_2 from biogenic origin in 2050 (WWF, 2009). Within the last 10 years, however, only one further study has assessed and quantified BECCS. Extending the scope to cover both biogas and bioethanol plants (but excluding biodiesel production), the calculations only resulted in 8.5 Mt CO_2 captured and stored (BMU, 2014). Nevertheless, the number of studies that explicitly exclude BECCS also remained relatively low: only three studies deliberately decided against this technology option due to (a) general skepticism about CCS (BUND, 2015), (b) various environmental reasons (UBA, 2019b), and (c) a prioritization of biomass for the industrial sector, leaving only a small biomass share to the energy sector so that large-scale BECCS solutions wouldn't be feasible (BDI, 2018).

CCS as mitigation option for coal or natural gas fired power stations was largely accepted and implemented until around 2010 but highly disputed afterwards (**Figure 5**). This strong opposition to fossil CCS might have negatively affected the perception toward CCS in general, causing more precaution as to the adoption of industrial or biomass-based CCS in German modeling frameworks. In fact, although first addressed in 2009, the intensified discussion of industrial CCS is a more recent development in Germany. The initial assumptions for CCS in the industry sector were very simplistic with unrealistic capture rates of 100% across all sub-sectors. This resulted in a first estimate of 37–53 Mt CO_2 sequestered from industrial point sources in 2050 (WWF, 2009). Despite more sophisticated calculation methods in the latest scenarios with industry CCS, the range of modeling results is still in the same order of magnitude with 16–93 Mt CO_2 (BMU, 2015a; BDI, 2018; BMWi, 2018; dena, 2018). The uncertainties already mentioned in section Challenges in Matching Biogenic and Industrial CO_2 Supply and Demand with respect to CO_2 availability from industrial sources apply here as well. Interestingly though, the depiction of industry CCS is mainly positively connoted as final resort for achieving carbon neutrality in the industrial sectors. However, despite its uncontested asset of creating negative emissions, BECCS did not mirror a similar dynamic in recent years.

The limited number of deliberate representation of BECCS—or CCS in general—is likely to be a result of various obstacles that scenario studies perceive in matters of CCS deployment (**Table 2**). Thirty out of the 66 analyzed studies raised at least one area of concern that either limited or prohibited CCS implementation in their scenarios. Over the entire assessment period from 2002 to 2019, technology-related items were the most prevalent. While techno-economic uncertainties such as the maturity and availability of capture technologies were more of a concern in the late 2000s, reservations are nowadays rather express with regard to the overall process efficiency and the energy penalty associated with the CO_2 capture. Within the category of economic arguments, studies are most critical about investment costs and risks on both plant scale and overall infrastructure. Generalized and often not further specified long-term risks for the environment are noted in every third scenario study. While storage capacity and competition for storage space and/or locations is in 8 studies an area of concern, the systems perspective of integrating CCS activities is less of a preoccupation.

As already mentioned, the frequency of these arguments, cumulated over time, points toward an early, and sustained preoccupation with techno-economic concerns (**Figure 6**). However, in parallel, a first sign of public awareness issues arises with the introduction of the EU CCS directive and its subsequent implementation in Germany. Similarly, in the post-Paris Agreement debate on decarbonization options, negative perceptions regarding public acceptance of CCS resurfaced in the scenarios. Interestingly, although none of the scenario studies provides evidence for the supposed societal non-acceptance, this arguments is the single most raised rationale against CCS. A study commissioned by the Federation of German Industries (BDI) partially attenuates this narrative: If there are no or only much more expensive alternatives to industrial CCS, both political and social acceptance is assumed (BDI, 2018). Insofar, public perception would only be a question of costs. Slightly more nuanced, the German Energy Agency (dena) approves CCS as last resort in spite of societal concern—but only if even more costly alternatives are already exploited (dena, 2018). The latest study sponsored by the Federal Ministry for Economic Affairs and Energy (BMWi) assumes that public acceptance is only a minor obstacle for CCS in the industrial sector due to the lack

TABLE 2 | Obstacles to (BE)CCS deployment mentioned in German scenarios ($n = 30$).

Main category [number of studies addressing at least one subcategory]		Sub-category [number of studies per item]	
Technology	19	Techno-economic uncertainties	13
		Energy and efficiency penalty	12
		Missing upscaling experience	4
Economy	18	Investment risks and operational costs	12
		Insufficient market penetration	6
		Economic viability	4
Policy and Society	17	Lack of public acceptance	14
		Legal/regulatory concerns	9
		Interdiction of CO_2 export for storage	2
Environment	13	Unknown long-term risks for the environment	10
		CO_2 leakage (e.g., ground water pollution)	8
		Security/ health concerns (e.g., accidents, explosion)	5
		Transport infrastructure as threat to natural landscapes	2
Storage capacity	11	Limited geological storage capacity	8
		Competition for storage: CCS vs. Geothermal energy	7
		Competition for storage: fossil vs. biogenic vs. industrial CO_2	2
Systems perspective	6	No CCS in power sector/other decarbonization options exist	4
		Complex infrastructure changes necessary for CCS integration	3

of cost-effective alternatives (BMWi, 2018). However, all of the recent publications supported by ministries, agencies or NGOs related to environmental matters or nature conservation either do not address or explicitly exclude CCS (BUND, 2015; BfN, 2018; BMU, 2019; UBA, 2019b). This being said, the political context of the CCS debate is likely to change with German Chancellor Angela Merkel putting the CCS debate back on the table in May 2019, veering away from the fossil CCS rhetoric to a focus on delivering the Paris Agreement (Bundeskanzleramt, 2019; Kornelius et al., 2019). These contrasting views suggest that the public acceptance argument is seemingly more a political one than a primarily societal one. This is further underpinned by the fact that there are also societal objections to and citizen initiatives against onshore wind parks (Reusswig et al., 2016; Langer et al., 2018), geothermal energy systems (Kunze and Hertel, 2017; Benighaus and Bleicher, 2019), or the extension of the transmission grid (Neukirch, 2016; Kühne and Weber, 2017). However, this does not prevent these options from being part of the future energy mix.

Other Biomass-Based NETs: Conserving Ecosystem Services

Besides BECCS, large-scale afforestation is the second most prominently featured NET option in numerous global IAMs such as AIM, GCAM, and MESSAGE-GLOBIOM (Forster et al., 2018). However, this is not the case in the present selection of scenario studies for Germany, at least not when it comes to large-scale implementation. For example, the word "afforestation" appears explicitly in only five studies, among which only a single analysis provides an estimation of the associated GHG emission reduction, namely an annual 18 t CO_2 per hectare when converting pastureland into forests (UBA, 2014). In addition, however, various studies mention measures to preserve at least the existing net carbon sink function of forests (WWF, 2009; BMU, 2019). These include, for example, some reserved areas for natural forest development as well as the implementation of sustainable forest management practices in the public forests (Greenpeace, 2015). In addition, arable land and grassland are partially converted into forest (BMU, 2015a, 2017).

Within the analyzed scenarios, the category of wetlands and ecosystem restoration follows a similar logic: no large-scale negative emissions initiatives, but individual measures to keep the land use, land use change and forestry (LULUCF) overall as a natural sink. In the scenarios, it is common practice to stop peat extraction on the one hand and to rewet peat soils on the other (UBA, 2014, 2019a,b; Greenpeace, 2015; BMU, 2019). A partial implementation of the measures can amount to a reduction of 13.3 Mt CO_2 in 2050. Savings of up to 37.5 Mt CO_2 are feasible if a full implementation takes place (BMU, 2015a).

In comparison, soil carbon sequestration (SCS) is rarely taken into account in the scenarios, based on the assumption that carbon uptake of agricultural soil is reversible and cannot be sustained in the longer run (UBA, 2014). Only a Greenpeace study assessed the potential of natural CO_2 sequestration, e.g., through increased cultivation of humus-building plants, potentially leading to a moderate GHG reduction of 3.8 Mt CO_2 in 2050 (Greenpeace, 2015). Information available for biochar is even less abundant, having only been mentioned once in a single study. Hence, these NET options are largely non-existent in the German decarbonization scenarios.

Beyond the different depths in which the respective NETs categories are represented in the scenarios, a common trend can

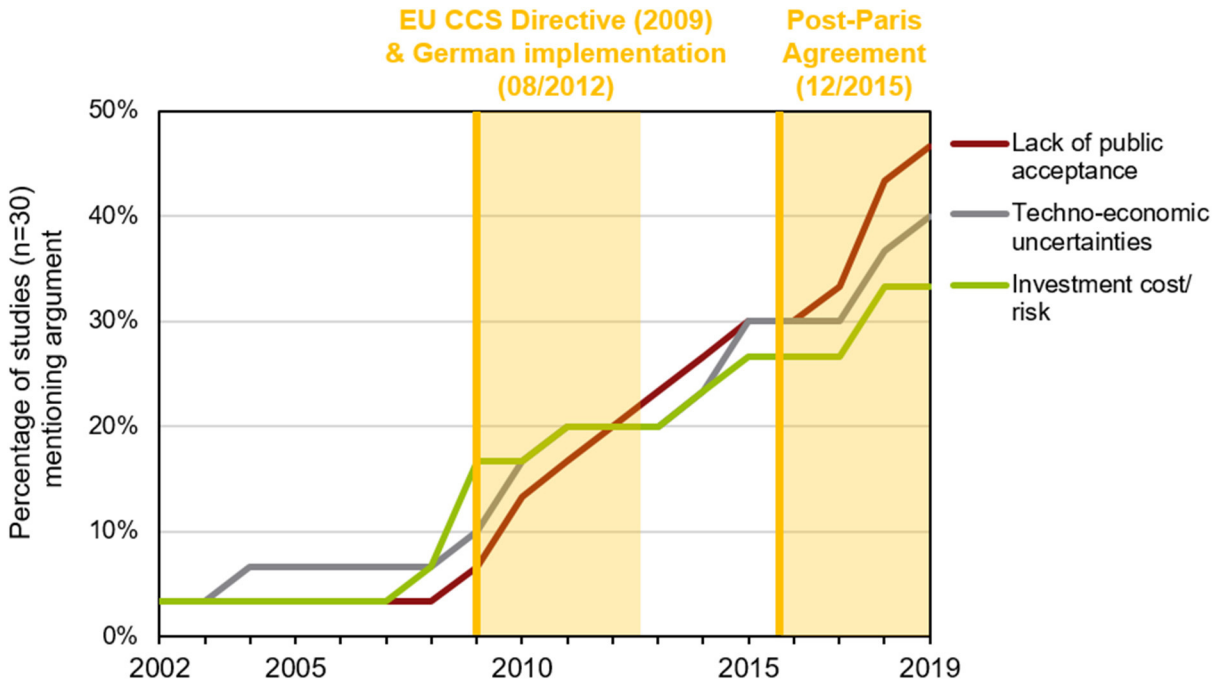

FIGURE 6 | Most frequently mentioned obstacles to (BE)CCS deployment in Germany.

nevertheless be identified: without exception, all scenario studies that provide more detailed assumptions and/or quantification of emission savings for the biomass-based NETs and the LULUCF sector in general have been financed by environmental ministries, agencies and NGOs. Other branches of government or industry are mostly limited to integrated energy system models for electricity, heat, and transport. However, in view of an economy-wide approach and to better reflect non-energy related emissions, the integration should more systematically extend to the LULUCF sector.

Moving From BCO_2 Blind Spots to an Overarching Scenario Framework

Revisiting the classification of BCO_2 concepts as set out in **Figure 1**, and contrasting it with the previous findings on each of the BCO_2 categories, there is only one bright spot: the energetic use of bio-resources. While this does not come as a surprise for the traditional bioenergy sector thanks to the longstanding tradition of biomass as energy carrier, the relatively strong representation of (biogenic) CO_2 utilization is, however, a rather new phenomenon. This can mainly be attributed to the ever growing role of sector coupling in Germany, necessitating besides hydrogen also a carbon source. Regarding bioenergy in combination with CCS, many studies rejected CCS so far based on the grounds of a diffuse and not evidence-based assumption of societal and political non-acceptance. However, the analysis has also shown that this is not set in stone, at least for industrial CCS. In this respect, BECCS could possibly also become an accepted or at least tolerated option in the medium to long term, in particular thanks to its unique selling point of sustainable energy production with simultaneous generation of negative emissions. To strengthen the representation of biomass for energetic use, including BECCS, in future scenarios, the underlying assumptions for biomass resource types, potentials and international trade should be documented more transparently as they heavily affect all subsequent decisions on the allocation of biomass to different sectors and ultimately also the amount of GHG emissions savings that can come from biomass use. In this regard, GHG emission accounting along the bioenergy lifecycle should be given greater attention in the scenario studies, notably but not limited to direct and indirect land use change effects in developing and emerging countries. In addition, biomass allocation needs to be put in a systems perspective, especially if BECCS is to play a role in the future energy system as it requires more large-scale and centralized bioenergy plants.

The competition for biomass resources extends to the material-related BCO_2 concepts. The analysis revealed that quantitative assessment of both biomass and biogenic CO_2 for material applications are mostly non-existent. Furthermore, if the concept of material use is qualitatively mentioned, this is solely done as a means to illustrate examples rather than for taking a holistic and structured approach to analyzing biomass use for all non-energetic purposes. Leaving significant room for improvement, the introduction of material flow analyses within the scenario frameworks could be instrumental in assessing these competing biomass uses, identify opportunities for cascading use strategies, and ultimately guide biomass allocation. This also constitutes a first step into an integrated bioeconomy thinking, i.e., "the knowledge-based production and use of renewable

resources, in order to provide products, processes and services in all areas of the economy, within the framework of an economic system that is viable for the future" (BMEL, 2014).

While energy and decarbonization scenario studies that were published within the last 10–15 years only scratched upon the surface of biomass-based NETs so far, modeling, and monitoring their carbon sink capacity and performance is a prerequisite for determining an acceptable amount of residual emissions in other sectors without compromising overall climate neutrality by the mid-century. However, this implies that competition for different land use options will increase as some of the land-based NETs are mutually exclusive. Therefore, it will be crucial to bridge the gap between energy and land use models in order to build an adequate framework for the integration of biomass-based NETs into German decarbonization scenarios.

CONCLUSION

This paper set out to explore the technology-openness of energy and decarbonization scenarios with respect to biomass-based carbon removal concepts (BCO_2). By performing a systematic review of 66 studies containing a total of 189 scenarios for Germany, the aim was to provide a first appraisal of the representation of BCO_2 in a scenario context and to formulate recommendations for their better integration into existing and future modeling frameworks.

Our findings indicate that bioenergy is the best-represented BCO_2 concept, however assumptions made for bioenergy potentials either take outdated references as assessment basis or are not detailed enough with regard to biomass resource types and GHG emission accounting. In contrast, the material biomass use perspective is largely not addressed, especially lacking quantified data. The challenge with biogenic CO_2 is to match its supply and demand, also in the light of other potential CO_2 sources from industry and direct air capture. Techno-economic assumptions and data for BECCS is available but has only been implemented in few scenarios, mainly due to an assumption of non-existent public acceptance. A critical review however suggests to revisit the public acceptance argument as scenario studies failed to provide evidence for their claim. Other NETs have—if at all—not been addressed under a large-scale negative emissions perspective but rather as conservation measure for its current carbon sink function.

Acknowledging that the aim of scenario modeling is not to replicate the reality but to explore different technology options and their interdependencies, the findings of this study indicate two major axes of improvement, namely the need for integrated energy-land modeling frameworks as well as the adoption of bioeconomy perspectives in the scenario narrative. This being said, extending the modeling scope increases complexity and creates trade-offs with regard to granularity. To tackle these challenges, soft-linking otherwise separate models could be envisaged. This allows in an iterative process to converge on key parameters instead of requiring a full model integration. Existing global IAMs can serve as a blueprint in this regard, such as the energy supply model MESSAGE linked via an emulator to the land use model GLOBIOM. In order to facilitate such integrated energy-land modeling frameworks, interdisciplinary research, and cooperation is of crucial importance. Having shown in this study that environmental organizations from the governmental and non-governmental sphere were most likely to publish scenario studies that do include land use considerations, they could be instrumental in funding and facilitating such interactions. Finally, beyond the topic of BCO_2 concepts, guidelines for standardized scenario documentations could support greater transparency and better comparability across models and scenarios.

AUTHOR CONTRIBUTIONS

AH devised the project with supervision by NS and DT. AH collected, analyzed, interpreted the data, and wrote the paper. All authors discussed the results and critically commented on the manuscript.

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Marginal Abatement Cost Curve of Industrial CO_2 Capture and Storage – A Swedish Case Study

Filip Johnsson, Fredrik Normann and Elin Svensson*

Department of Space, Earth and Environment, Chalmers University of Technology, Gothenburg, Sweden

Carbon capture and storage (CCS) is expected to play a key role to achieve deep emission cuts in the energy intensive industry sector. The implementation of carbon capture comes with a considerable investment cost and a significant effect on the plants operating cost, which both depend on site conditions, mainly due to differences in flue gas flow and composition and depending on the availability of excess heat that can be utilized to power the capture unit. In this study we map the costs required to install and operate amine-based post-combustion CO_2 capture at all manufacturing plants in Sweden with annual emissions of 500 kt CO_2 or more, of both fossil and of biogenic origin, of which there are 28 plants (including a petrochemical site, refineries, iron and steel plants, cement plants and pulp and paper mills). The work considers differences in the investment required as well as differences in potential for using excess heat to cover the steam demand of the capture process. We present the resulting total CO_2 capture costs in the form of a marginal abatement cost curve (MACC) for the emission sources investigated. Cost estimations for a transport and storage system are also indicated. The MACC shows that CO_2 capture applied to 28 industrial units capture CO_2 emissions corresponding to more than 50% of Swedish total CO_2 emissions (from all sectors) at a cost ranging from around 40 €/t CO_2 to 110 €/t CO_2, depending on emission source. Partial capture from the most suited sites may reduce capture cost and, thus, may serve as a low-cost option for introducing CCS. The cost for transport and storage will add some 25 to 40 €/t CO_2, depending on location and type of transportation infrastructure.

Keywords: CCS, CO_2 capture, MACC, industrial, case study

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****Correspondence:***
Filip Johnsson
filip.johnsson@chalmers.se

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INTRODUCTION

In order to limit global warming in line with The Paris Agreement – to limit warming to well below 2°C – requires global emissions to become zero around the middle of the century. It is also likely that emissions has to be net-negative in the second half of the century since the global society most likely will overshoot the carbon budget required to stabilize climate at a temperature well below 2°C [e.g., (IEA, 2013; Rogelj et al., 2018)]. The basic industries, such as pulp and paper, cement, (petro) chemicals, and ferrous- and non-ferrous metal plants, are large point sources of CO2 emissions and deep cuts in their emissions are therefore required over the next decades. This is a challenge since it will not be sufficient with incremental measures such as improved efficiency and introduction of best available process technologies. Instead, transformative changes in the processes

are required. There are only a few such options of which carbon capture and storage (CCS) is one (De Pee et al., 2018). Since CCS can mitigate up to 80–95% of the CO_2 emissions from flue gases, it offers a promising mitigation option if applied to the basic industry. Since CCS requires significant amounts of energy, it is important to find ways to integrate the capture process with the rest of the process to achieve as efficient capture as possible.

In this work, we focus on amine-based carbon capture as a reference capture technology. Post combustion capture is a mature capture technology and the processes involved (amine scrubbing of CO_2) has been applied in industry for many years. Post combustion is applied in CCS schemes in a number of relatively large-scale projects around the world (Global CCS Institute, 2019), mainly to power plants, and can therefore be seen as proven technology with a TRL level of 8–9, although when applied to industrial emission sources it must be tested and demonstrated before full scale implementation. Other technologies for carbon capture are also promising in specific industrial applications. For example, although less mature, oxy-fuel combustion was evaluated as the least-cost option for a cement plant (Garðarsdóttir et al., 2019), and both oxy-fuel combustion and chemical looping combustion seem promising in terms of energy penalty when CO_2 is captured from fluid catalytic cracker plants in oil refineries (Güleç et al., 2020). However, amine-based post combustion is currently the only technology with a potential to be more generally viable, especially when retrofitting existing plants. Thus, the other capture technologies are either less mature, have not been tested at scale or would require that the existing industry process is replaced or redesigned making it difficult to assess not only the technology performance but also the cost of capture.

Yet, the specific capture cost (€/t CO_2) applying post combustion, will depend on which process to which it is applied, such as if there is access to internal excess heat to power part of the capture process and on the CO_2 concentration in the flue gas and the size of the flue gas flow. The capture cost typically decreases with increased concentration in the flue gas and increased size of the flue gas flow (Garðarsdóttir et al., 2018), although this is not necessarily valid in the cases where there is access to excess heat within the process to which CCS is applied. Two recent examples from the iron and steel industry are given by Sundqvist et al. (2018), who investigate alternatives for partial CO_2 capture in the steel industry by utilizing excess heat to power the capture process, and Mandova et al. (2019) who explore the CO_2 emission reduction potential of bio-CCS in European steel industry. An example from the cement industry is the techno-economic case study assessment presented by Jakobsen et al. (2017), who conclude, amongst other things, that economy of scale of full-scale capture (in terms of specific capture cost) is nearly outweighed by higher steam cost compared to partial capture, in which case the steam demand can be covered by excess heat.

Literature on carbon capture in petroleum refineries include, for example, a study by Andersson et al. (2016), who did a techno-economic case-study based assessment of excess heat-driven carbon capture, and showed how the specific cost for carbon capture increases with the amount of carbon captured due to decreasing availability of excess heat of sufficiently high temperature. Another example is the study of Berghout et al. (2019) who assessed deployment pathways for emissions reductions in refineries by considering carbon capture in combination with other mitigation options. Several studies have investigated the possibility for carbon capture in the pulp and paper industry [see e.g., Onarheim et al. (2017) and references therein]. Based on such studies it may be concluded that the potential for post-combustion technology is more promising for chemical market pulp mills than for integrated pulp and paper mills due to potentially larger amounts of excess heat available in chemical market pulp mills that can be used to cover the heat demand of the capture process. For systematic reviews of academic literature on industrial CCS including its cost, see Kuramochi et al. (2012) and Leeson et al. (2017). In their review they conclude that reported costs for CCS vary within a large range and that the uncertainty in future costs of industrial CCS is significant.

Onarheim et al. (2015) mapped the potential for CCS in the Nordic countries and highlight the sources with highest potential. Following their work, our recent study, (Garðarsdóttir et al., 2018), mapped the investment required to install carbon capture (amine absorption) at all industrial sites in Sweden with annual emissions of 500 kt CO_2 or more (fossil and biogenic), which corresponds to more than 80% of the CO_2 emissions from the basic industry. While site-specific conditions were considered for the estimation of capital costs, the steam cost was assumed to be the same for all sites in this study. The study concludes that there are large differences in the investment required between industrial sectors and even between industrial sites within the same sector where, as mentioned above, the size of the CO_2 source and the CO_2 concentration are important factors. In the case of Sweden, steel mills, cement plants, and the recovery boiler of large pulp mills require a relatively low specific investment. Although, the investment is a considerable share of the total CO_2 capture cost, the cost of steam is generally the dominating cost item. As discussed by Biermann et al. (2018), the steam cost depends on the current plant energy system, e.g., the amount of excess heat available, access to a steam cycle, and capacity of the present steam generation equipment. The cost of steam will also depend on energy market conditions and different steam generation options may be favored over time or dependent on time of the year or day. Consequently, and as also supported by several of the papers cited above, the cost of steam will be highly site specific and in cases where there is excess heat available to generate the steam required for the capture process, this has the potential to significantly reduce the cost of carbon capture.

This work follows our previous work (Garðarsdóttir et al., 2018) using Sweden as a case study. Sweden is a heavily industrialized region and in addition to being representative for a region with large industrial emission sources, there are also large biogenic emission sources whereas electricity and heat generation have low fossil-fuel based carbon emissions (23 g CO_2/kWh produced), with plans to phase out or shift fuel in the remaining fossil-fuel plants.

The long-term climate goal set by the Swedish Government is that Sweden should have net zero greenhouse gas emissions

by Year 2045, which translates to 85% reduction from domestic emissions where the remaining 15% can be met by measures abroad, so called negative emissions from bio-CCS (BECCS) or land use change measures (Swedish Ministry of the Environment, 2017). In 2017, the total Swedish emissions of fossil greenhouse gases were approximately 53 Mt of CO_2 equivalents per year of which 43 Mt are CO_2 emissions. More than one third of the fossil-fuel CO_2 emissions originates from the basic industry (oil refineries 3 Mt/year, minerals/cement 3 Mt/year, iron and steel 6 Mt/year, chemicals 1.5 Mt/year) [Naturvårdsverket (Swedish Environmental Protection Agency), 2018]. The large point sources of biogenic CO_2 emissions are market pulp mills and integrated pulp and paper mills. This adds another 20 Mt/year of CO_2 to the total emissions (Swedish Environmental Protection Agency [SEPA], 2016b). In Sweden, very few, if any, new industrial plants can be assumed to be built within the foreseeable future, which means that CCS should be considered as a retrofit option for existing sites. Due to the magnitude of emissions from the pulp and paper industry, there is significant potential for negative emissions by means of BECCS. The potentially significant contribution of BECCS for national greenhouse gas reduction is similar to a country like Brazil, for which it has been concluded that carbon capture from biogenic sources in ethanol production could play an important role for carbon mitigation provided sufficiently strong climate policy are put in place (Rochedo et al., 2016). However, an important difference between the Swedish biogenic emission sources investigated in this work and the Brazilian cases is that the Swedish emission sources are in the form of pulp and paper plants, which are much larger than the ethanol plants in Rochedo et al. (2016). This, together with their coastal location, makes transport (by ship) much less costly than the costs of the large (inland) pipeline network required to be established for ethanol plant capture in Brazil.

As in our previous work (Garðarsdóttir et al., 2018) we investigate industrial emission sources in Sweden of at least 500 kt CO_2/a. In this study we extend our previous study by also considering differences between the site's potential for using excess heat to cover the heat demand of an amine-based capture process. This is achieved by indicatively mapping the energy systems of the industrial plants to estimate the cost of steam at the individual sites. As a result, total CO_2 capture costs are presented as a marginal abatement cost curve (MACC) for all Swedish industrial sites with CO_2 emissions exceeding 500 kt/a. A curve indicating the cost for a transport and storage system connecting successively more emission sources is also generated. Thus, the work provides the societal cost for amine-based carbon capture based on site specific conditions for existing industrial sites within the basic industry.

MATERIALS AND METHODS

To estimate the availability of industrial low-cost heat for CO_2 capture, an inventory of Swedish industrial sites and their excess heat levels was conducted utilizing the Chalmers Industrial Case Study Portfolio (ChICaSP) (Svensson et al., 2019).

Chalmers Industrial Case Study Portfolio

A detailed description of the ChICaSP can be found in Svensson et al. (2019). In short, it includes the 65 industrial sites in Sweden totaling (fossil+biogenic) CO_2 emissions >50 kt/a in 2016 within the mineral extraction and manufacturing sectors and includes data with a focus on process heat use and carbon dioxide emissions. The type of data included in CHICaSP is reported annually and openly from government agencies, industry organizations and similar, as shown in **Table 1**. In addition, the database also contains site specific information available from various research projects as exemplified in **Table 2**, giving more detailed information on the energy system of individual sites, although the coverage and consistency between sites are lower.

In this study, ChICaSP was used to identify the industrial sites with total fossil and biogenic CO_2 emissions of above 500 kt per year or more, a limit which was chosen arbitrarily to include the majority of the emission and focus on the units for which the specific capture cost is expected to be the lowest. The 500 kt threshold give a total of 28 industrial plants investigated in this work and accounting for more than 80% of the CO_2 emissions from the basic industry and with the distribution of the CO_2 emissions between the sites given in **Table 3**. The estimation of the availability of low-cost heat for carbon capture at the investigated sites

TABLE 1 | Publicly available data categories summarized for all industry sites in the ChICaSP data base.

Data entry	Source
Site coordinates according to WGS84	European Pollutant Release and Transfer Register (PRTR) European Environment Agency [EEA], 2016
County and Municipality	Swedish PRTR Swedish Environmental Protection Agency [SEPA], 2016b
Industrial sector	Swedish Environmental Protection Agency. Same classification used for reporting of greenhouse gas emissions to Statistics Sweden (SCB) and for managing statistics related to the EU-ETS Swedish Environmental Protection Agency [SEPA], 2016a
Type of site/mill/plant	Various sources, incl. company environmental report, web pages, etc.,
Emitted CO_2: fossil, biogenic, total	Fossil emissions: Data reported within the EU-ETS, in Sweden compiled by the Swedish Environmental Protection Agency Swedish Environmental Protection Agency [SEPA], 2016a. Biogenic emissions and fossil emissions for sites not covered by the EU-ETS: Swedish PRTR, based on data reported to the Swedish Environmental Protection Agency Swedish Environmental Protection Agency [SEPA], 2016b
Net electricity consumption	Company environmental reports. For pulp and paper mills, data from environmental reports are available in the forestry industries' environmental database, which has been used as the primary source Skogsindustrierna, 2016. A few additional sources, such as company web sites, have been used when the environmental reports have not been available or are lacking information.
Gross heat exports	
Annual production	

by the case study portfolio as further described in the following section.

Mapping of Site-Specific Industrial Excess Heat Levels

In this work, we define the term excess heat as all heat that is or can be made available at the site at a lower cost than the cost required for new steam generation capacity. This implies that also heat that would require some investment, e.g., in waste heat boilers or retrofits of heat exchanger networks, is considered as a potential excess heat source. Consequently, excess heat may refer to heat generated from cooling of process streams as well as heat from waste heat boilers from currently unutilized off-gases, or from utilizing spare capacity in the site's existing utility system. We also include steam that is currently utilized for low-pressure condensing power generation. However, it is assumed that heat for carbon capture should not compete with current district heating deliveries.

The steam temperature required for regenerating the amine was considered to be 130°C (3 bar), which also sets the temperature requirement for the excess heat. The heat demand for carbon capture depends on a number of factors in solvent and process design and site conditions but is typically in the range of 2.5–3.5 MJ/kg CO_2 captured. The quantity of excess heat at a site expressed in MJ per kg of carbon emitted can be compared to the heat demand of carbon capture to give an indication of the feasibility of using excess heat for the capture process.

Since data on process heating and cooling demands were not available with the same level of detail for all industrial sites, and furthermore, may change with plant retrofits for increased heat recovery, only indicative estimations were sought for the excess heat assessments. In this work, excess heat-driven carbon capture was considered if the amount of excess heat at sufficient temperature was estimated to be at least around 1 MJ per kg CO_2 emitted, i.e., if about one third of the heat required for capture of all the emitted CO_2 could be provided by excess heat. The chosen value is considered a reasonable assumption to represent a trade-off, which does not exclude too many sites to be of interest for excess heat-driven capture (which would be the case with a higher cut-off value) and also ensures that partial capture plants sized by the availability of excess heat gets acceptable economy of scale or that sites with 90% capture attain a significant reduction in capital costs for new heat production when excess heat is considered.

The excess heat estimation was made based on the data available in ChICaSP. Of the 28 industrial sites included in the analysis, data on the plant energy system detailed enough for a *quantitative* (MJ/kg CO_2) or *descriptive* (above or below approximately 1 MJ/kg CO_2) estimate was available for 12 sites (43%). For the remaining 16 sites, the excess heat potential was estimated based on results and experience from studies of similar process plants and model mills. In particular, 14 of these remaining sites are of a type of pulp and paper mill for which detailed models are available (Kraft market pulp mills, TMP mills, integrated and non-integrated mills), developed mainly within the Swedish research program FRAM (Future Resource Adapted Mill) (Delin et al., 2005). An estimate of the excess heat available for capture was made using the process models for a standard mill and the information about the type of mill available from the ChICaSP. The energy system of the remaining two sites (a cement plant and an oil refinery) were estimated by extrapolating from similar sites in ChICaSP. It should, thus, be noted that the data quality of the estimated excess heat potential varies from actual site measurement data to data acquired from site modeling based on statistics for the type of industry.

TABLE 2 | Case specific data categories summarized in the ChICaSP data base when available for the specific industry site.

Data section	Description
General information	Sources, confidentiality and other types of general case file information
Overall balance	Overall mass and energy balances of the plant, including resource consumption, emissions, energy use, production levels and similar
Process description	Overview of the production processes at the site. Generally presented as a process flow sheet
CO_2 sources	Typically presents flue gas specifications for different stacks
Utility system	Description and data for the internal site energy system, which generally refers to the steam system with boilers, turbines etc.,
Heating and Cooling demand	Results from pinch analyses including stream data, pinch curves and the assumptions and system boundaries used for the analysis
Existing heat exchanger network	Information about the existing heat exchanger network structure, or the placement of existing heaters and coolers
Excess heat	Available assessments of excess heat

Cost Estimations

We evaluate the costs for CCS assuming a standard MEA-based CO_2 absorption process is adopted for all industrial processes. Consequently, we do not account for potential future technology development such as new absorbents or the adoption of more suitable capture technologies for specific industrial processes. The resulting marginal abatement cost curve may therefore be regarded as a conservative estimate of CCS in the Swedish industrial sector with respect to its focus on high TRL options.

The investment cost for CO_2 capture applied in this study is adopted from our previous work (Garðarsdóttir et al., 2018). In that work, the capital cost (CAPEX) was estimated with a detailed individual factor estimation method and considered the treated volume flow of gases and the flue gas CO_2 concentration of the individual stacks at each site. The costs were calculated for 90% capture rate. The annualized CAPEX is calculated with 25 years lifetime (out of which 3 years are for construction) and a 7.5% rate of return.

The transport and storage costs are estimated based on the work by Kjärstad et al. (2016) and adopted to the present analysis by Garðarsdóttir et al. (2018). The transport and storage solution includes storage in the Norwegian North Sea or Baltic

Sea[1] and transport by ship from five hubs distributed near the Swedish coast in proximity to large emission sources. As an approximation, these are assumed to correspond to Hub 1-2 and 4-6 in Kjärstad et al. (2016), [see also Figure 1 of Kjärstad et al. (2016)], which shows these transport hubs on a map). Note, however, that the costs of the transport hubs do not include the costs for an onshore collection system from sources to the hub. The cost estimation assumes that the entire investment cost for a transport hub that connects all relevant emission sources to a storage site is taken once the first source is connected to that hub. The specific investment cost for operating at a specific hub is, thus, decreased as more sources and larger flows of CO_2 is handled at each hub, respectively. The sources are assumed to be connected in order of specific capture cost, i.e., the source with the lowest specific capture cost is connected first. Each hub is also associated with a fixed specific operating cost, which in this work is set to 9 €/t CO_2 transported. The assumption that the transport cost is independent of the distance is reasonable for ship transports as, e.g., Kjärstad et al. (2016) showed that there is only a weak cost dependence on distance for ship transport. The storage cost differs depending on which storage location is connected to each hub and is either 7 or 15 €/t CO_2 (Garðarsdóttir et al., 2018). For more details on what is included in the cost of the transport and storage infrastructure see Kjärstad et al. (2016).

Operating expenditures (OPEX) are dominated by the cost of heat supply for solvent regeneration, but also include other utilities, maintenance, and labor. The operational costs are divided into fixed and variable OPEX. Fixed costs include maintenance and labor costs and are not dependent on the plant utilization. The annual maintenance cost is estimated as 4% of the investment. Labor cost for operators and engineers is set to 820 k€/a independent of plant size. All utilities are considered to be delivered by external systems and are, thus, considered as pure operational costs (i.e., no investments are required). Utilities include the cost of steam, electricity and cooling water required to run the process and are directly connected to the amount of CO_2 captured. The specific steam demand (D_{steam}; tonne of steam/kg CO_2 captured) depends on the initial CO_2 concentration and the capture rate as the energy to separate CO_2 from the gas

[1]It should be noted that storage in the Baltic Sea is not a near-term option due to lack of detailed geological data, in spite of significant storage potential.

TABLE 3 | Industrial plants considered in the study, i.e., all Swedish industrial plants with annual CO_2 emissions of 500 kt or more (Year 2016 data).

ID-#	Company/Plant	Industry	Emission source(s)	CO_2 Emissions (kt/year)		
				Biogenic	Fossil	Total
C-1	Borealis Stenungsund	Chemicals	Cracker	0	664	664
IS-1	Lulekraft Luleå	Iron and Steel	CHP integrated steel mill	0	1 795	1 795
IS-2	SSAB Luleå	Iron and Steel	Blast furnace, Hot Stoves	0	1 511	1 511
IS-3	SSAB Oxelösund	Iron and Steel	CHP, Hot stoves, Coke plant	0	1 502	1 502
Mi-1	Cementa Slite	Minerals	Cement kiln	162	1 742	1 904
PP-01	Södra Cell Mönsterås	Pulp	Recovery boiler, Lime kiln	1 811	23	1 834
PP-02	Stora Enso Skutskär	Pulp	Recovery boiler, Lime kiln	1 826	1	1 826
PP-03	Metsä Board Husum	Pulp and Paper	Recovery boiler, Lime kiln	1 483	60	1 543
PP-04	BillerudKorsnäs Gruvön	Pulp and Paper	Recovery boiler, Lime kiln	1 280	16	1 296
PP-05	BillerudKorsnäs Gävle	Pulp and Paper	Recovery boiler, Lime kiln	1 239	17	1 256
PP-06	SCA Östrand	Pulp	Recovery boiler, Lime kiln	1 135	32	1 166
PP-07	Smurfit Kappa Kraftliner Piteå	Pulp and Paper	Recovery boiler, Lime kiln	1 120	13	1 133
PP-08	BillerudKorsnäs Skärblacka	Pulp and Paper	Recovery boiler, Lime kiln	996	11	1 007
PP-09	Södra Cell Mörrum	Pulp	Recovery boiler, Lime kiln	952	17	969
PP-10	Södra Cell Värö	Pulp	Recovery boiler, Lime kiln	958	10	968
PP-11	Stora Enso Skoghall	Pulp and Paper	Recovery boiler, Lime kiln	889	53	943
PP-12	Holmen Iggesund	Pulp and Paper	Recovery boiler, Lime kiln	884	27	911
PP-13	BillerudKorsnäs Karlsborg	Pulp and Paper	Recovery boiler, Lime kiln	877	6	882
PP-14	Stora Enso Nymölla	Pulp and Paper	Recovery boiler	746	30	775
PP-15	SCA Munksund	Pulp and Paper	Recovery boiler, Lime kiln	689	17	706
PP-16	BillerudKorsnäs Frövi	Pulp and Paper	Recovery boiler, Lime kiln	682	14	696
PP-17	Mondi Dynäs	Pulp and Paper	Recovery boiler, Lime kiln	633	15	648
PP-18	Rottneros, Vallviks Bruk	Pulp	Recovery boiler, Lime kiln	604	6	610
PP-19	Nordic Paper, Bäckhammar	Pulp and Paper	Recovery boiler, Lime kiln	539	7	546
PP-20	Domsjö Fabriker	Pulp and Biorefinery	Recovery boiler	476	11	487
R-1	Preemraff Lysekil	Refinery	SMR, Heaters, Cracker	0	1 428	1 428
R-2	St1 Refinery	Refinery	Heaters	0	535	535
R-3	Preemraff Göteborg	Refinery	Heaters	0	504	504

The total amount of CO_2 emissions considered is 29.5 Mt/year out of which 20.0 Mt/year is of biogenic origin.

stream is higher the lower the CO_2 concentration. The specific steam demand will also depend on the design of the absorption process and the solvent used; however, only simple cycle with MEA is considered in this work. The price of steam (P_{steam}; €/t) depends on the site and energy market conditions. The specific steam cost (C_{steam}; €/kg CO_2 captured) is given by the following correlation with the steam demand derived from the estimates in Garðarsdóttir et al. (2018).

$$C_{steam} = P_{steam} D_{steam}$$

$$D_{steam} = 1.1 X_{CO_2}^{-0.13}$$

where X_{CO_2} is the volume fraction in percent of CO_2 in the inlet stream. The electricity and cooling duty are not as dependent on the CO_2 concentration of the inlet stream and the site-specific conditions as the steam demand and therefore their specific costs are kept constant in the cost estimation.

The price of steam (P_{steam}) was estimated based on the indicative availability of excess heat estimated for the sites. The cost for erecting a new boiler and steam cycle on site results in a cost of steam of 20 €/MWh with the assumptions used in Ali et al. (2018). However, if excess heat can be used to generate parts of the required steam, the cost is obviously lower. **Table 4** gives one example for each type of industry of how the cost of steam may be affected depending on the steam demand. The pulp mill as well as the steel mill have relatively large steam cycles on site from which steam could be bled. For these plants, the cost is related to the loss in electricity production from the steam cycles. The cement plant and the refinery have some excess heat in the form of warm off-gases that could be used to generate low-pressure steam. In these cases, steam costs are related to the cost of the waste heat boilers. The steel mill also has excess heat within the process that may be recovered, e.g., from flue gas heat recovery, coke dry quenching, and dry slag granulation. The excess heat sources are, thus, more diversified for the steel mill than for the other plants.

The cost levels indicated in **Table 4** were applied for estimating site-specific steam costs according to the identified excess heat classifications. Note, however, that **Table 4** is based only on an example of one particular site per industrial sector. If the excess heat potential was estimated to be low, the steam cost was taken at the level of 20 €/MWh, corresponding to the costs of new boiler and steam cycle capacity.

TABLE 4 | Example for one particular site of each industrial sector of the assumed cost of steam for carbon capture through amine absorption for plants with excess heat above 1 MJ/kg CO_2 generated depending on type of industry and degree of capture.

	Partial capture (€/MWh)	90% capture(€/MWh)
Pulp mill	10.0	16.7
Steel mill	5.2	15.1
Cement plant	2.5	14.2
Refinery	9.5	16.5

For plants without excess heat the steam cost is 20 €/MWh. Based on the case studies in Sundqvist et al. (2018); Andersson et al. (2014), Mathisen et al. (2018); Skagestad et al. (2018).

If the excess heat potential for a particular site was estimated to be high (i.e., higher than the above mentioned threshold of 1 MJ/kg emitted CO_2), the steam cost for capturing up to 1/3 of the site emissions was taken at a cost level corresponding to the average cost of steam up to 1 MJ/kg while the steam cost for the rest of the CO_2 emissions captured was taken as the cost assumed for 90% capture from the entire site (20 €/MWh). The petrochemical plant was assumed to follow the same steam cost profile as the refineries. In case of partial capture, the 1/3 of the CO_2 at the site with lowest specific capture cost was captured utilizing the available excess heat. It is worth noting that the steam cost model neglects the fact that specific investment costs depend on the capacity needed, and instead follows the assumption that steam cost is included as a utility cost.

RESULTS

Figure 1 gives the marginal abatement cost curve (MACC) for capture for the 28 plants in **Table 3** (with 90% capture rate) together with the corresponding curve for transport and storage from these sites. The reason for the number of emission sources (steps in the figure) being much higher than 28 is that several of the sites contain multiple emission sources.

Applying capture to the 28 industrial units investigated in this work corresponds to a reduced emission of around 23 Mt CO_2/a, which is more than 50% of Swedish total CO_2 emissions (from all sectors). Another way to see it is that since the Swedish forestry management currently gives an increase in the carbon stock in the forests, Sweden's 20 Mt of fossil fuel emissions are more than offset by applying capture on the 28 plants. From **Figure 1** it can be seen that the cost of applying CO_2 capture, transport and storage (adding the two curves) to the 28 industrial units is ranging from around 80–135 €/t CO_2. Yet, due to that a transport infrastructure consisting of hubs and ship transport can be organized in different ways – during a ramp up of CCS – adding the curves in this way will only give an approximate cost at a certain amount of CO_2 captured (abscissa value). The details of the capture costs are presented in **Table 5**.

The difference in capture cost of 40–110 €/t CO_2 is considerable, although not surprising given the heterogeneity of the emission sources. Low-cost sources typically have high CO_2 concentrations, large volume flows, and availability of excess heat and are found, e.g., in the iron and steel and cement industry (such as IS-1, IS-2 and Mi-1 in **Table 5**). The sources with highest cost correspond to low-volume sources for which no excess heat is available for capture. In this study, these are mainly the lime kilns in the pulp and paper mills, which stand for only a minor share of total site emissions and therefore suffer from poor economy of scale. As can be seen, a considerable part of the total emissions captured can be captured at capture costs below 70 €/t CO_2. It should be noted that 15 Mt out of the 23 Mt CO_2 captured are of biogenic origin.

As shown in **Figure 1**, the transport and storage costs range from around 40 €/t CO_2 for a small system to around 25 €/t CO_2 for a large system. These cost estimates are based on the assumptions described in section "Materials and Methods." For

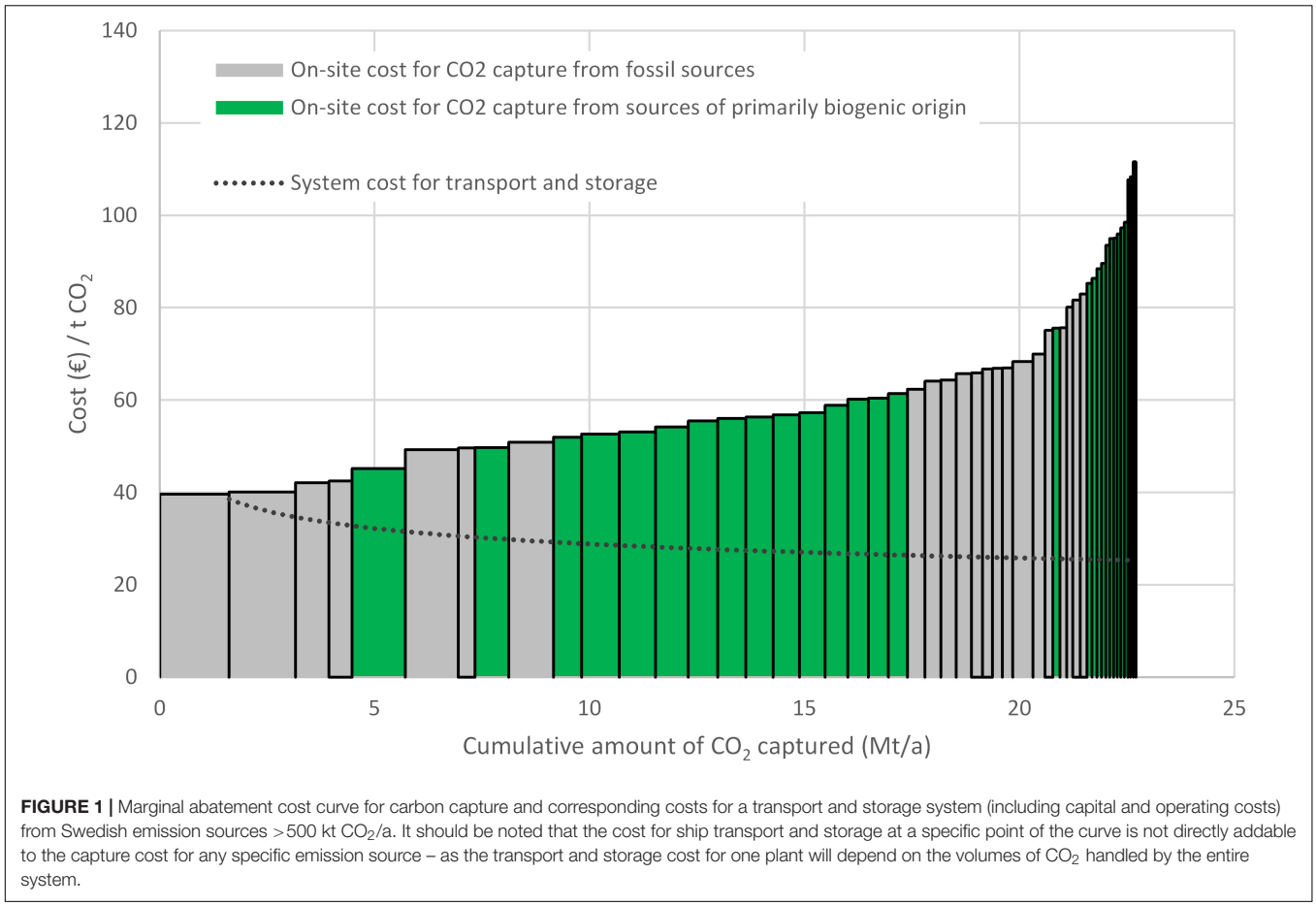

FIGURE 1 | Marginal abatement cost curve for carbon capture and corresponding costs for a transport and storage system (including capital and operating costs) from Swedish emission sources >500 kt CO_2/a. It should be noted that the cost for ship transport and storage at a specific point of the curve is not directly addable to the capture cost for any specific emission source – as the transport and storage cost for one plant will depend on the volumes of CO_2 handled by the entire system.

further clarification, it should be noted that the cost for ship transport and storage is not directly addable to the capture cost – as the specific cost for the specific plant will depend on the volumes of CO_2 handled by the entire system. The cost for transport and storage should correspond to the volume treated by the system and not the volume of the specific plant. These costs also assume that the sources are implemented in the order presented in the MACC.

Figure 2 illustrates the impact of excess heat utilization on the capture cost for the emission sources. The consideration of excess heat availability (black dotted line) in the cost estimations yields only moderate cost reductions for total site carbon capture (red dashed line) The reason for this is that it is not possible to power 90% capture for the total site emissions by excess heat alone, but an investment in new steam generation capability to cover the remaining heat demand is required and this steam will come at full-cost. This cost assessment considers 1 MJ of excess heat per kg of CO_2 emitted for all plants with excess heat even if for some sites, significantly more heat could be available. The fact that excess heat is not capable of powering 90% capture of the site emissions is, however, true for all sites considered.

The effect on the capture cost by being able to fully exclude new steam generation capacity is illustrated by the cost for partial capture, which is the amount of CO_2 possible to capture by using excess heat (Biermann et al., 2018). This allows for more significant capture cost reductions, as also shown in **Figure 2** (see blue line). To derive the results shown in **Figure 2**, capture was considered only for the sites estimated to have more than 1 MJ of excess heat available per kg of CO_2 emitted. This level of excess heat availability was used to determine the amount of CO_2 captured for these sites also if more excess heat may be available. Note that industry-specific, and not site-specific, costs of excess heat were considered. The avoidance potential is naturally reduced by only considering excess heat-driven carbon capture, resulting in about 4.5 Mt/year captured (blue solid curve in **Figure 2**) at capture costs below 30 €/t CO_2 as can be seen from the solid blue curve in **Figure 2**. Partial capture is to be considered as an early mover option that may develop over time or to be combined with other low-carbon technologies. It should be noted that the total system costs might be increased if later deciding to capture the remaining emissions.

DISCUSSION

For the refineries and the petrochemical cluster in Stenungsund, the potential of excess heat utilization was found to be heavily temperature dependent. For example, considering process streams that are currently cooled in air or water coolers in Stenungsund, about 10 MW of heat is available >130°C (used in

TABLE 5 | Mapping of potential for implementing carbon capture and storage at Swedish emission sources >500 kt/a.

ID-#/heat potential	CAPEX	OPEX		TOTAL	Transport Hub[2]	Distr. Heat[4]	Heat estimate[5]
	M€/a[1]	Fixed, M€/a	Variable, M€/a	Spec., €/tCO_2			
C-1 [6,7]	13	6	10	61	#6		ChICaSP Quant.
IS-1 [3]	22	9	33	40	#1	yes	ChICaSP Quant.
IS-2 [3]	13	6	14	42	#1		ChICaSP Quant.
IS-3					#4		ChICaSP Desc.
St. 1	6	3	6	67			
St. 2	6	3	6	67			
St. 3	10	5	8	43			
Mi-1	22	10	30	40	#4	yes	Other
PP-01					#4	yes	ChICaSP Quant.
St. 1	20	9	27	45			
St. 2	5	3	4	76			
PP-02					#2		Other
St. 1	20	9	32	49			
St. 2	5	3	4	76			
PP-03					#2		Other
St. 1	18	8	27	51			
St. 2	5	3	4	80			
PP-04					#6	yes	Other
St. 1	16	7	23	53			
St. 2	4	3	3	85			
PP-05					#2	yes	Other
St. 1	16	7	22	53			
St. 2	4	3	3	86			
PP-06 [8]					#2	yes	ChICaSP Quant.
St. 1	15	7	17	50			
St. 2	4	2	3	89			
PP-07					#1	yes	Other
St. 1	15	7	20	54			
St. 2	4	2	3	90			
PP-08					#4	yes	Other
St. 1	14	6	18	56			
St. 2	4	2	2	94			
PP-09					#5	yes	Other
St. 1	13	6	17	56			
St. 2	4	2	2	95			
PP-10 [8]					#6	yes	ChICaSP Desc.
St. 1	13	6	14	52			
St. 2	4	2	2	95			
PP-11					#6	yes	Other
St. 1	13	6	17	56			
St. 2	4	2	2	96			
PP-12					#2	yes	ChICaSP Quant.
St. 1	13	6	16	57			
St. 2	4	2	2	97			
PP-13					#1		ChICaSP Desc.
St. 1	13	6	16	57			
St. 2	4	2	2	99			
PP-14	12	5	14	59	#5	yes	Other
PP-15					#1	yes	Other
St. 1	11	5	12	60			
St. 2	3	2	2	108			

(Continued)

TABLE 5 | Continued

ID-#/heat potential	CAPEX	OPEX		TOTAL	Transport Hub[2]	Distr. Heat[4]	Heat estimate[5]
	M€/a[1]	Fixed, M€/a	Variable, M€/a	Spec., €/tCO_2			
PP-16					#4	yes	Other
St. 1	11	5	12	60			
St. 2	3	2	2	108			
PP-17					#2		ChlCaSP Desc.
St. 1	10	5	11	61			
St. 2	3	2	1	112			
PP-18					#2		Other
St. 1	10	5	11	62			
St. 2	3	2	1	114			
PP-19					#6		Other
St. 1	9	5	10	64			
St. 2	3	2	1	120			
PP-20	9	4	9	64	#2		Other
R-1 [7]							
St. 1	8	4	7	50			
St. 2	10	5	9	66			
St. 3	8	4	8	70	#6		ChlCaSP Quant.
St. 4	6	3	5	75			
R-2 [7]					#6	yes	Other
St. 1	8	4	5	66			
St. 2	6	3	5	82			
R-3 [7]					#6	yes	ChlCaSP Quant.
St. 1	7	4	5	67			
St. 2	6	3	4	83			

Heat availability: Green >1MJ/kg CO_2 emitted, Red no significant potential for low-cost steam generation.
[1]Adopted from the work by Garðarsdóttir et al. (2018). [2]Adopted from the work by Kjärstad et al. (2016). [3]IS-1 is a CHP plant integrated with the IS-2 steel mill. [4]Potential competition with district heating. [5]Method for excess heat estimation: ChlCaSP Quant.) Quantitative estimate based on data available in case study portfolio, ChlCaSP Desc.) Descriptive assessment based on information in case study portfolio Other) Estimate based on comparison with models or similar sites. [6]Part of industrial cluster. Excess heat assumed to be available also from neighboring process plants. [7]Excess heat potential strongly dependent on temperature requirement. [8]Mill increased capacity significantly after 2016. Excess heat estimation made for prospective future production levels and site energy system.

this work), while 20 MW and 60 MW is available at temperatures >110°C and >95°C, respectively. Thus, at >130°C, Stenungsund is not deemed to have potential for low-cost steam generation above 1 MJ per kg of CO_2 emitted. However, at >110°C or >95°C there is a potential. For these types of industrial processes, new solvents that allows for lower regeneration temperatures could significantly increase the potential for excess heat-driven carbon capture.

Utilization of excess heat for carbon capture competes with other heat utilization. In particular, in Sweden today, heat is often delivered to district heating networks. However, it should be noted that CCS and district heating does not necessarily compete about heat from the same temperature levels. District heating generation is non-phase changing and can be supplied by low-temperature sensible heat while the reboiler of the capture process requires heat at constant temperature for evaporation. Consequently, heat may still remain available for district heating after the full potential for excess heat-driven carbon capture has been exploited. A more direct competition for the heat is observed between carbon capture and power generation in low-pressure steam turbines. In this aspect, the development of the decarbonization of the electricity market is important to consider in the decision between using excess heat for electricity generation or for carbon capture. In a decarbonized electricity system, more emissions are avoided by using the heat for the capture process.

In this study, we considered site-specific conditions such as geographic location, characteristics of individual emission sources and excess heat availability. However, the effect of other criteria such as space availability at the industrial sites, and seasonal variations in heat availability and/or emissions remain to be investigated. In regions with water scarcity, this may be a critical factor to consider [see e.g., (Merschmann et al., 2013)], but this is not critical in the Swedish context.

Furthermore, the impact of partial capture on CO_2 transportation costs have not been investigated in detail in this work. It was assumed that the entire cost of a transport hub was taken as soon as the first emission source was connected to that hub. This results in high specific investment costs for CO_2 transport if only low volumes of CO_2 (e.g., few sources, partial capture) are transported to storage. This assumption corresponds well with the fact that transportation costs are

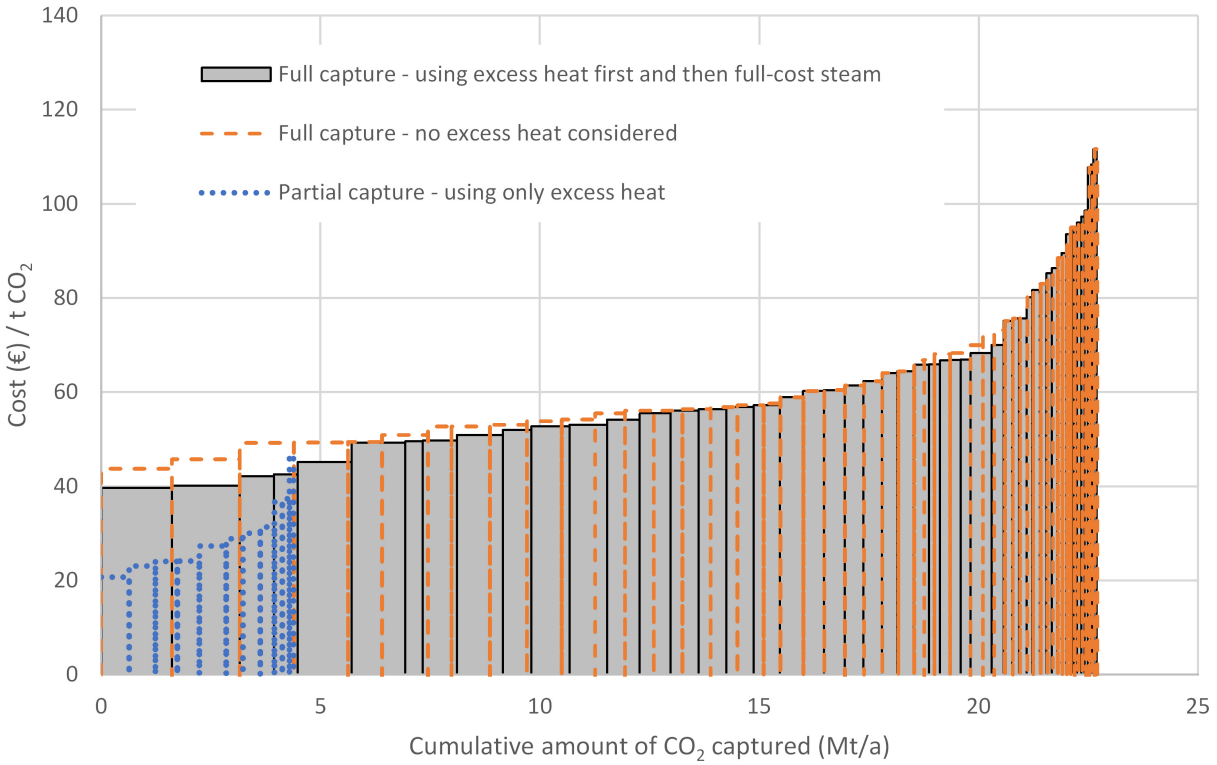

FIGURE 2 | Effect of excess heat on capture costs for Swedish emission sources >500 kt CO_2/a. The black dotted line is the same as in **Figure 1**. The red dashed line represents 90% capture of total site emissions using only full-cost steam. The blue line represents partial capture of the CO_2 that can be captured by means of 1 MJ of excess heat per kg CO_2 emitted at a given site.

considerably higher for partial CO_2 capture due to poor economy of scale of transport infrastructure (particularly from emission sources to transport hubs).

The transformation required in the industrial sector for reaching not only required emission reductions, but also energy efficiency and renewable energy targets, is likely to involve major changes in the existing industrial processes and its associated infrastructure including the close down of some plants. Besides these changes, new products, processes and technologies can be expected to emerge. This includes, for example, the integration of new biobased processes in (petro) chemical process plants (causing a shift from fossil to more biogenic sources of CO_2), improvements in energy efficiency (reducing the amount of excess heat), and process electrification (reducing or eliminating process CO_2 emission as well as affecting excess heat availability). The analysis in this study does not provide a picture of the costs of carbon capture and storage to the future zero-emitting industry but to the present industry. This picture is to serve as an indication of potential cost levels, and how these are affected by various site-specific conditions, for the starting point rather than for the end-game. The results show that to achieve cost efficient carbon capture CCS should be considered in the transformation of the industrial sector. Furthermore, policy instruments that are efficiently strong to allow for CCS are crucial for its implementation; sufficiently high costs of emission allowances within the EU-ETS system for the fossil-fuel based emissions and that policy instruments (EU-ETS or other instrument) need to recognize negative emissions so as to allow for capture and storage of biogenic emissions.

CONCLUSION

This work estimates the total costs for amine-based CO_2 capture at all (28) Swedish industrial plants that emits 500 kt CO_2 or more per year. The costs and potential captured emissions are presented in the form of a marginal abatement cost curve (MACC) for industrial post-combustion capture in Sweden. The work maps the plants' energy systems and estimates the cost of steam required for carbon capture at each specific site. The mapping considers the potential for low-cost steam generation by utilizing excess heat from process cooling, and available capacity in the existing on-site energy system.

The MACC shows that CO_2 capture applied to the 28 industrial sites capture CO_2 emissions corresponding to more than 50% of Swedish total CO_2 emissions (from all sectors). When costs for a transport and storage system is included, this can be achieved at a cost ranging from around 80 €/t CO_2 to 135 €/t CO_2, depending on emission source. The results show a considerable difference in capture cost between emission sources (40–110 €/t) and that around 2/3 of the emission from the >500 kt/a sources could be captured at a cost of 70 €/t. Partial

capture can reduce capture cost and, thus, may serve as a low-cost option for introducing CCS.

Applying the estimations of available excess heat for powering capture in the cost estimations, only yield moderate cost reductions at 90% capture rate. The main reason is that 90% carbon capture is not possible to power without investment in new steam generation capacity in any of the cases considered. The effect on the capture cost by only capturing the amount of CO_2 which can be covered by excess process heat – the partial capture cases – yield capture costs in the range of 20–40 €/t. This is, however, only an option for a limited amount of the emissions (around 4.5 Mt/a compared to 23 Mt/a in the 90% capture case).

The case study portfolio and database, ChICaSP, utilized is considered a valuable tool including detailed site data for more than 40% of the plants considered and data for an indirect assessment for the remaining plants utilizing experience and external sources. To further improve the estimation more case studies should be performed along with an assessment of mitigation options besides carbon capture, like electrification and increased biomass utilization.

DATA AVAILABILITY STATEMENT

The datasets for this study can be found in the cited articles as well as in the tables provided.

AUTHOR CONTRIBUTIONS

FJ and FN conceived the study together and ES provided significant parts of the data processing and evaluation. All authors discussed and interpreted results and jointly wrote the manuscript.

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Conflict of Interest: The authors declare that the research was conducted in the absence of any commercial or financial relationships that could be construed as a potential conflict of interest.

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CORRECTION
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Corrigendum: Marginal Abatement Cost Curve of Industrial CO_2 Capture and Storage – A Swedish Case Study

Filip Johnsson, Fredrik Normann and Elin Svensson*

Department of Space, Earth and Environment, Chalmers University of Technology, Gothenburg, Sweden

Keywords: CCS, CO_2 capture, MACC, industrial, case study

A Corrigendum on

Marginal Abatement Cost Curve of Industrial CO_2 Capture and Storage – A Swedish Case Study
by Johnsson, F., Normann, F., and Svensson, E. (2020). Front. Energy Res. 8:175. doi: 10.3389/fenrg.2020.00175

In the original article, there were two typographical errors in the citations included in the foot notes of **Table 5** as published. **In foot note 1, the citation to Garðarsdóttir et al. (2018) was incorrectly written as Güleç et al. (2020). In footnote 2, the citation to Kjärstad et al. (2016) was incorrectly written as Skogsindustrierna (2016).** The corrected **Table 5** appears below.

In the original article, information was missing in the reference for **European Environment Agency [EEA] (2016),** which was incorrectly written as **European Environment Agency [EEA] (2016). *European Pollutant Release and Transfer Register (E-PRTR).* Copenhagen: European Environment Agency.** It should be **European Environment Agency [EEA] (2016). *European Pollutant Release and Transfer Register (E-PRTR).* Copenhagen: European Environment Agency. Available online at: http://prtr.eea.europa.eu/#/facilitylevels (accessed September 30, 2018).**

In the original article, the reference for **Swedish Ministry of the Environment (2017)** was incorrectly written as **Government Offices of Sweden, and Ministry of the Environment and Energy (2017). *The Swedish Climate Policy Framework.* Stockholm: Ministry of the Environment.** It should be **Swedish Ministry of the Environment (2017). *The Swedish Climate Policy Framework.* Stockholm: Government Offices of Sweden; Ministry of the Environment.**

In the original article, the reference for **Skogsindustrierna (2016)** was incorrectly written as **Skogsindustrierna, (2016). *Skogsindustriernas Miljödatabas (Forest Industries Environmental Database.* Bentley, WA: Forest Industries Federation.** It should be **Skogsindustrierna (2016). *Skogsindustriernas Miljödatabas Forest Industries Environmental Database.* Stockholm: Swedish Forest Industries Federation. Available online at: http://miljodatabas.skogsindustrierna.org/ (accessed August 31, 2018).**

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****Correspondence:***
Filip Johnsson
filip.johnsson@chalmers.se

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The authors apologize for these errors and state that this does not change the scientific conclusions of the article in any way. The original article has been updated.

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TABLE 5 | Mapping of potential for implementing carbon capture and storage at Swedish emission sources >500 kt/a.

ID-#/Heat Potential	CAPEX	OPEX		TOTAL	Transport Hub[2]	Distr. Heat[4]	Heat estimate[5]
	M€/a[1]	Fixed, M€/a	Variable, M€/a	Spec., €/tCO_2			
C-1[6,7]	13	6	10	61	#6		ChICaSP Quant.
IS-1[3]	22	9	33	40	#1	yes	ChICaSP Quant.
IS-2[3]	13	6	14	42	#1		ChICaSP Quant.
IS-3					#4		ChICaSP Desc.
St. 1	6	3	6	67			
St. 2	6	3	6	67			
St. 3	10	5	8	43			
Mi-1	22	10	30	40	#4	yes	Other
PP-01					#4	yes	ChICaSP Quant.
St. 1	20	9	27	45			
St. 2	5	3	4	76			
PP-02					#2		Other
St. 1	20	9	32	49			
St. 2	5	3	4	76			
PP-03					#2		Other
St. 1	18	8	27	51			
St. 2	5	3	4	80			
PP-04					#6	yes	Other
St. 1	16	7	23	53			
St. 2	4	3	3	85			
PP-05					#2	yes	Other
St. 1	16	7	22	53			
St. 2	4	3	3	86			
PP-06[8]					#2	yes	ChICaSP Quant.
St. 1	15	7	17	50			
St. 2	4	2	3	89			
PP-07					#1	yes	Other
St. 1	15	7	20	54			
St. 2	4	2	3	90			
PP-08					#4	yes	Other
St. 1	14	6	18	56			
St. 2	4	2	2	94			
PP-09					#5	yes	Other
St. 1	13	6	17	56			
St. 2	4	2	2	95			
PP-10[8]					#6	yes	ChICaSP Desc.
St. 1	13	6	14	52			
St. 2	4	2	2	95			
PP-11					#6	yes	Other
St. 1	13	6	17	56			
St. 2	4	2	2	96			
PP-12					#2	yes	ChICaSP Quant.
St. 1	13	6	16	57			
St. 2	4	2	2	97			
PP-13					#1		ChICaSP Desc.
St. 1	13	6	16	57			
St. 2	4	2	2	99			

(Continued)

TABLE 5 | Continued

ID-#/Heat Potential	CAPEX	OPEX		TOTAL	Transport Hub[2]	Distr. Heat[4]	Heat estimate[5]
	M€/a[1]	Fixed, M€/a	Variable, M€/a	Spec., €/tCO_2			
PP-14	12	5	14	59	#5	yes	Other
PP-15					#1	yes	Other
St. 1	11	5	12	60			
St. 2	3	2	2	108			
PP-16					#4	yes	Other
St. 1	11	5	12	60			
St. 2	3	2	2	108			
PP-17					#2		ChICaSP Desc.
St. 1	10	5	11	61			
St. 2	3	2	1	112			
PP-18					#2		Other
St. 1	10	5	11	62			
St. 2	3	2	1	114			
PP-19					#6		Other
St. 1	9	5	10	64			
St. 2	3	2	1	120			
PP-20	9	4	9	64	#2		Other
R-1[7]					#6		ChICaSP Quant.
St. 1	8	4	7	50			
St. 2	10	5	9	66			
St. 3	8	4	8	70			
St. 4	6	3	5	75			
R-2[7]					#6	yes	Other
St. 1	8	4	5	66			
St. 2	6	3	5	82			
R-3[7]					#6	yes	ChICaSP Quant.
St. 1	7	4	5	67			
St. 2	6	3	4	83			

Heat availability: Green >1 MJ/kg CO_2 emitted, Red no significant potential for low-cost steam generation.
[1]Adopted from the work by Garðarsdóttir et al. (2018). [2]Adopted from the work by Kjärstad et al. (2016). [3]IS-1 is a CHP plant integrated with the IS-2 steel mill. [4]Potential competition with district heating. [5]Method for excess heat estimation: ChICaSP Quant.) Quantitative estimate based on data available in case study portfolio, ChICaSP Desc.) Descriptive assessment based on information in case study portfolio Other) Estimate based on comparison with models or similar sites. [6]Part of industrial cluster. Excess heat assumed to be available also from neighboring process plants. [7]Excess heat potential strongly dependent on temperature requirement. [8]Mill increased capacity significantly after 2016. Excess heat estimation made for prospective future production levels and site energy system.

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Sequential Combustion in Steam Methane Reformers for Hydrogen and Power Production With CCUS in Decarbonized Industrial Clusters

Laura Herraiz[1], Mathieu Lucquiaud[1], Hannah Chalmers[1] and Jon Gibbins[2]*

[1] School of Engineering, The University of Edinburgh, Edinburgh, United Kingdom, [2] Department of Mechanical Engineering, The University of Sheffield, Sheffield, United Kingdom

In future energy supply systems, hydrogen and electricity may be generated in decarbonized industrial clusters using a common infrastructure for natural gas supply, electricity grid and transport and geological storage of CO_2. The novel contribution of this article consists of using sequential combustion in a steam methane reforming (SMR) hydrogen plant to allow for capital and operating cost reduction by using a single post-combustion carbon capture system for both the hydrogen process and the combined cycle gas turbine (CCGT) power plant, plus appropriate integration for this new equipment combination. The concept would be widely applied to any post-combustion CO_2 capture process. A newly developed, rigorous, gPROMs model of two hydrogen production technologies, covering a wide range of hydrogen production capacities, thermodynamically integrated with commercially available gas turbine engines quantifies the step change in thermal efficiency and hydrogen production efficiency. It includes a generic post-combustion capture technology – a conventional 30%wt MEA process - to quantify the reduction in size of CO_2 absorber columns, the most capital intensive part of solvent-based capture systems. For a conventional SMR located downstream of an H-class gas turbine engine, followed by a three-pressure level HRSG and a capture plant with two absorbers, the integrated system produces ca. 696,400 Nm^3/h of H_2 with a net power output of 651 MWe at a net thermal efficiency of 38.9%$_{LHV}$. This corresponds to 34 MWe of additional power, increasing efficiency by 4.9% points, and makes one absorber redundant compared to the equivalent non-integrated system producing the same volume of H_2. For a dedicated gas heated reformer (GHR) located downstream of an aeroderivative gas turbine engine, followed by a two-pressure level HRSG and a capture plant with one absorber, the integrated system produces ca. 80,750 Nm^3/h of H_2 with a net power output of 73 MWe and a net thermal efficiency of 54.7%$_{LHV}$. This corresponds to 13 MWe of additional power output, increasing efficiency by 13.5% points and also makes one absorber redundant. The article also presents new insights for the design and operation of reformers integrated with gas turbines and with CO_2 capture.

Keywords: sequential combustion, low-carbon hydrogen, steam methane reformer, gas heated reformer, carbon capture and storage, gas turbine combined cycle

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****Correspondence:***
Laura Herraiz
l.herraiz@ed.ac.uk

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INTRODUCTION

Electricity and hydrogen are two low-carbon energy vectors expected to play key roles in a zero carbon economy, for example to decarbonize power, buildings (heating and cooling), transport and industry sectors. In future energy supply systems there will be a number of examples of both vectors being generated from natural gas at the same location, where a common infrastructure is available for natural gas supply, electricity grid connection and transport and geological storage of CO_2 in carbon capture, utilization and storage (CCUS) industrial clusters (BEIS, 2018).

The possibility of producing hydrogen by a low-carbon route and storing it at scale makes it a potentially valuable complement in the long-term decarbonization of parts of the energy system where electrification is not feasible and/or more expensive. Besides being a fuel or raw material for some energy intensive industries, low-carbon hydrogen can replace natural gas for space heating in buildings, industrial processes and back-up power generation and be used as a fuel in heavy transport. Hydrogen distribution networks are also anticipated, provided that sufficient volumes of hydrogen can be produced at a competitive price (Committee on Climate Change [CCC], 2018).

Natural gas reforming with carbon capture and storage (CCS) is expected to be a cost-effective option for industrial scale production of low-carbon hydrogen and can therefore help lay the foundation for much higher use of hydrogen across the whole economy (Committee on Climate Change [CCC], 2018). Currently steam reforming of natural gas or light hydrocarbons at an appropriate temperature and pressure in the presence of a suitable metal-based catalyst is the leading source of hydrogen used in petrochemical and petroleum refining applications, yet it has high emissions of carbon dioxide, at approximately 7 to 10 kg_{CO2}/kg_{H2} on average. Modern steam methane reformers (SMRs) are widely used for hydrogen production and have achieved high efficiencies, reducing CO_2 emissions down to nearly 10% above the theoretical minimum and further reduction would only be possible with CCS (IEAGHG, 2017b). In addition to the supply of natural gas as feedstock for synthesis gas and hydrogen production in a SMR, the combustion of natural gas and the tail gas from hydrogen production and separation provides the thermal energy for the high temperature heat transfer necessary to drive the endothermic reforming reactions in the catalytic reactor.

The novel contribution of this article consists of a technique for modifying the combustion in an SMR to allow for capital and operating cost reduction by integration to use a single post-combustion carbon capture (PCC) system for both the SMR and a combined cycle gas turbine (CCGT) power plant, plus appropriate integration for this new equipment combination. A review of other types of hydrogen production facilities with CCS that are also currently being considered for imminent deployment is beyond the scope of this study, but the SMR with PCC in its current form appears competitive (e.g., see Element Energy Ltd, 2018) and thus a description of possible improvements through such integration is topical because it could provide additional options for potential industrial users to consider.

Sharing the CO_2 capture process is possible via sequential combustion of the SMR fuel gases in the gas turbine exhaust flue gas. The relatively large amount of excess oxygen in the flue gas is used as the source of oxygen for the combustion taking place in the furnace or combustion chamber of the SMR.

The concept of sequential combustion is critical to the thermodynamic integration of hydrogen production with a gas turbine. Sequential combustion makes use of the excess oxygen in exhaust gases to complete a further stage of combustion; it has previously been investigated for coal and gas-fired power plants with CCS with the objective of maintaining the site power output and achieving capital cost reduction in the CO_2 capture process.

For markets with access to competitive natural gas prices and the possibility of using the CO_2 for enhanced oil recovery (EOR), González Díaz and co-workers (González Díaz et al., 2016) propose the use of sequential supplementary firing (SSF) of natural gas in the heat recovery steam generator (HRSG) of a CCGT power plant to achieve a ca. 50% reduction in the total volume of flue gas generated, which leads to a ca. 15% reduction in capital cost while maintaining the net power output of a CCGT power plant with CCS. Oxygen levels as low as 1 vol% may be practically achievable in a CCGT with sequential supplementary firing (Kitto and Stultz, 1992).

Sánchez del Río and co-workers (Sanchez del Rio et al., 2017) investigate the use of a gas turbine for re-powering a pulverized coal power plant retrofitted with CCS. After recovering heat from a gas turbine exhaust to increase steam production, the exhaust flue gas enters the hot windbox of the pulverized coal boiler, where it replaces secondary air to allow for sequential combustion to take place. In this case, oxygen levels are brought down as low as practically possible at 3 vol% (Kitto and Stultz, 1992).

Sequential Combustion in Steam Methane Reforming Hydrogen Plants

For sequential combustion to be applied for the integration of hydrogen and electricity production with CO_2 capture, a fairly conventional steam methane reformer is located downstream of a commercially available gas turbine engine. The reformer must be sized so that the oxidant stream for combustion matches the flue gas volume of an available gas turbine; the former are typically specially made while gas turbines are standard products. The fuel in the SMR is a mixture of the tail gas from hydrogen production and additional natural gas. The SMR furnace is followed by a heat recovery steam generator (HRSG), which generates the steam required for process use and for electricity generation in the steam turbine of a combined power cycle.

The cooled flue gas exiting the HRSG enters a post-combustion carbon capture system, where the CO_2 generated

Abbreviations: CCGT, combined cycle gas turbine; CCS, carbon capture and storage; CCUS, carbon capture, utilization and storage; GHR, gas heated reformer; GT, gas turbine; HP, high pressure; HRSG, heat recovery steam generation; IP, intermediate pressure; *LHV*, low heating value (MJ kg^{-1}); LP, low pressure; η_{H2}, hydrogen production efficiency (%); η_{th}, thermal efficiency (%); $\dot{m}$, mass flow rate (kg/s); PCC, post-combustion CO_2 capture; PSA, pressure swing adsorption; $\dot{Q}$, heat input (MW_{th}); SC, steam cycle; SMR, steam methane reformer; ST, steam turbine; VSA, vacuum swing adsorption; $\dot{W}$, power output/power consumption (MWe); WGS, water-gas-shift.

in the SMR furnace, including carbon species in the tail gas from hydrogen production, and in the gas turbine combustor is removed. Cost reduction in the capture process is achieved by reducing the number and the size of absorbers due to a reduction in the overall volume of the flue gas entering the carbon capture plant, a direct consequence of the use of the GT flue gas for sequential combustion. The integrated configuration can produce a combination of low-carbon hydrogen and low-carbon electricity with a reduction in total flue gas flow of approximately 30% and a favorable CO_2 concentration, i.e., 10 to 15 vol% CO_2 in this case compared to 6.5 to 10 vol% by mixing the two flue gas streams in a non-integrated configuration.

Sequential combustion of natural gas in gas turbine combustion gases in the furnace of a SMR is demonstrated at commercial scale at Air Products' hydrogen production facilities on site of the Valero Port Arthur Refinery in Texas, United States (Santos, 2015; Preston, 2018) in operation since 2013. The facility consists of an integrated hydrogen and cogeneration plant where a fraction of the gas turbine exhaust gas goes to the SMR furnace and the remainder to a newly added conventional HRSG. A new vacuum-swing adsorption (VSA) system for capturing CO_2 from the syngas stream is located downstream of the water-gas shift reactor and upstream of the existing pressure-swing adsorption (PSA) facility for H_2 purification, to achieve partial CO_2 capture from the plant as part of a US DOE CCUS demonstration program (Air Products, 2011). The SMR furnace was retrofitted with low-NO_x burners to avoid an increase in NO_x emissions caused by a higher flame temperature as the result of the lower CO_2 concentration in the tail gas from the hydrogen purification system used as fuel when CO_2 is captured from the syngas stream. Additional steam generation in the new-built HRSG offsets the reduction in power and steam production due to the addition of CO_2 capture. The facility continued to produce hydrogen, steam and power in order to meet pre-existing contractual commitments and be able to operate up to 100% design capacity. Although the facility captures 90% of the CO_2 in the synthesis gas stream, the overall CO_2 capture level is limited to 60% since there is no post-combustion capture taking place downstream of the

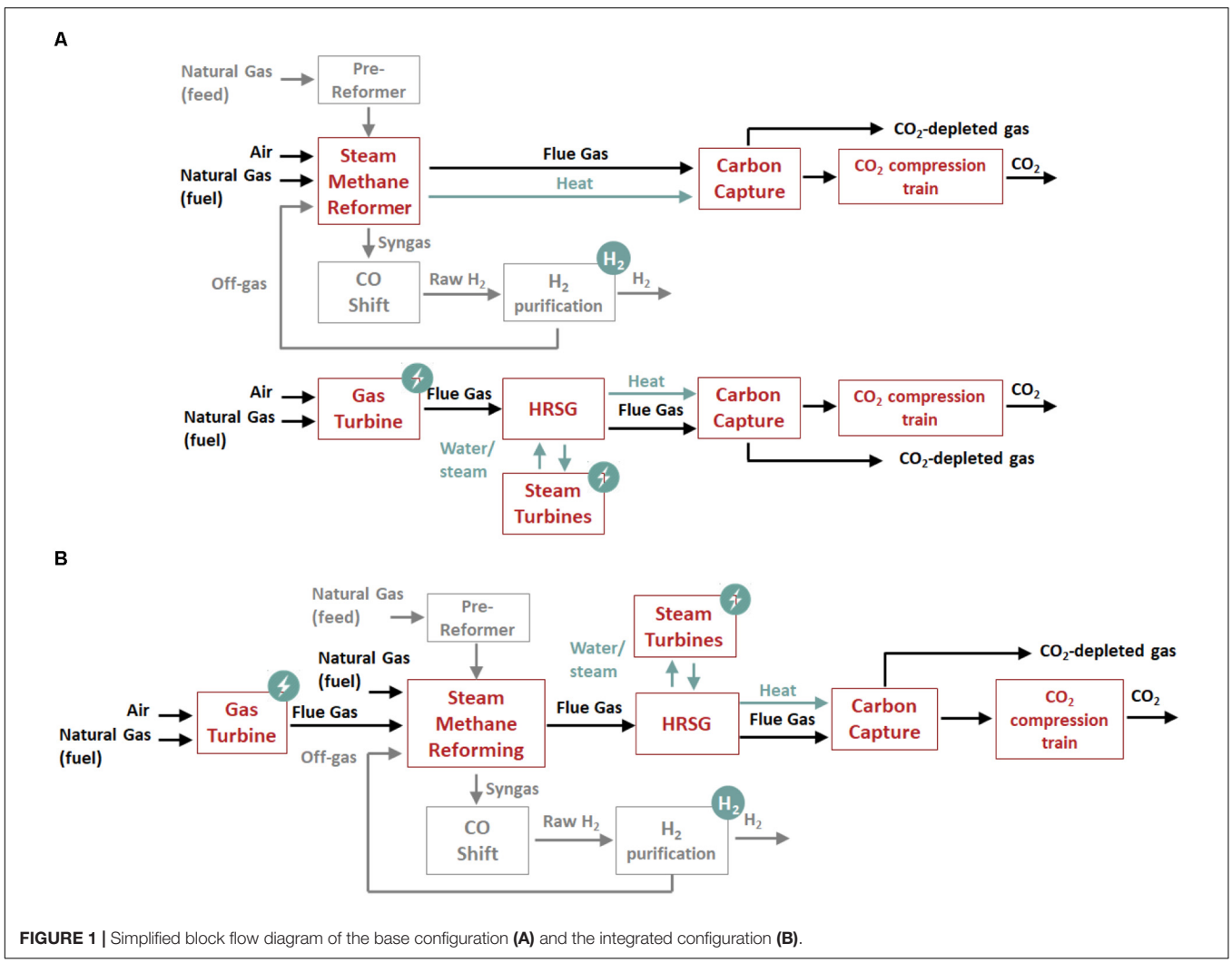

FIGURE 1 | Simplified block flow diagram of the base configuration **(A)** and the integrated configuration **(B)**.

SMR furnace for CO_2 from the combustion of natural gas and PSA tail gas.

Figure 1 shows schematic diagrams of the proposed integrated system consisting of an SMR hydrogen plant and a CCGT power plant with a shared post-combustion carbon capture system (**Figure 1B**), and an alternative base case counterfactual where a hydrogen plant and a CCGT power plant are each equipped with their respective carbon capture plants and produce hydrogen and electricity independently (**Figure 1A**).

The performance assessment of the thermodynamic integration is conducted for two reforming technologies widely considered for synthesis gas production in a hydrogen production plant:

- A steam methane reformer (SMR) with the endothermic reforming reactions being carried out in catalyst-filled tubes placed in a gas-fired radiative furnace as the source of energy. Radiation is the primary heat-transfer mechanism along with convection heat transfer from the furnace gas to the catalytic tubes to provide the thermal energy required for the reforming reactions. Typical hydrogen production volumes are between 2,000 and 300,000 Nm^3/h (Corso, 2019).
- A gas heated reformer (GHR) or convective reformer consisting of a combustion chamber followed by a tubular reactor packed with catalyst. The steam reforming process is similar to the conventional SMR described above, but heat is mainly transferred by convection from the combustion gases to the catalyst-filled tubes (Wesenberg et al., 2007). Convective reformers are stated to allow a more compact design and higher efficiencies. It is possible to minimize steam generation in the process, resulting a reforming section without export of steam. Typical hydrogen production volumes are between 5,000 and 50,000 Nm^3/h (Haldor Topsoe, 2007).

These two reforming technologies allow for investigation of a wide range of hydrogen production capacities and integration options for a reformer with different sizes of standard commercial gas turbine engines, i.e., a heavy duty gas turbine and an aeroderivative gas turbine. The selection of the appropriate standard gas turbine is based on the typical volume of exhaust flue gases and thus the oxygen content required for the integration with each hydrogen process with the size of the steam methane reformer and the gas heated reformer then matched to the GT based on the amount of heat released during combustion. An overview of the investigated configurations is presented in **Table 1**. They are compared in terms of net power output and thermal efficiency on the basis of the same hydrogen production. The hydrogen production volume of the SMR and GHR in the integrated configurations are respectively 3.5 and 2.5 higher than the largest commercial unit, at the time of writing, but there is a likely drive toward larger units, since worldwide hydrogen demand is expected to increase from 35 to 1,100 TWh per annum in 2030 (up to 1% of global primary energy demand), scaling up to 300 - 19,000 TWh per annum in 2050 (up to 8% of global primary energy demand), as reported in Committee on Climate Change [CCC] (2018).

The reduction in size of the capture plant is evaluated in terms of number of absorber columns and packing volume. The base case configurations for an SMR and a GHR based hydrogen plant are described in **Supplementary Appendices A, B**

A STEAM METHANE REFORMING HYDROGEN PLANT INTEGRATED WITH A H-CLASS GAS TURBINE COMBINED CYCLE

Process Description of the Hydrogen Plant and the CCGT Power Plant Equipped With CO_2 Capture

SMR Hydrogen Process and CCGT Power Plant

Figure 2 shows a schematic diagram of a purpose-built steam methane reformer (SMR) furnace where sequential combustion of natural gas and reformer tail gas takes place, using the excess oxygen in the gas turbine exhaust flue gas. The process flow diagram of the integrated configuration consisting of a purpose-built SMR for hydrogen production located downstream of a commercially available H-class gas turbine engine is illustrated in **Figure 3**. The hydrogen plant produces ca. 696,400 Nm^3/h (16 kg/s) of H_2 at 25 bar and 40°C.

The gas turbine exhaust flue gas is therefore used as the source of oxygen for the combustion of the tail gas from the hydrogen purification unit, as primary fuel, and natural gas, for additional fuel as required, in the burners of the SMR furnace. The heat released in the combustion is used to provide the sensible heat to increase the natural gas feedstock temperature up to the reaction temperature and the heat for the endothermic methane reforming process. The main heat transfer mechanism is radiation from the furnace walls and the flame itself, along with convection from the hot combustion gas to the catalyst-filled tubes.

The syngas production process is identical to that of the conventional SMR hydrogen plant of the base case configuration described in **Supplementary Appendix A**. A desulfurized and pre-heated natural gas stream is mixed with steam to achieve a steam to carbon ratio of 3 in the feed stream of the main reformer. Excess steam needs to be provided to drive the reforming reactions toward CO_2 and H_2 rather than CO and H_2O, and to avoid thermal cracking of the hydrocarbons and coke formation. The mixture of natural gas and steam enters first the pre-reformer, an adiabatic reactor where light hydrocarbons, i.e., mainly C2 + and olefins, are fully converted to CO and H_2. It then enters the catalyst-filled tubes of the main reformer at ca. 600 °C. Inside the catalytic tubes, methane reacts with steam at a relatively high temperature and moderate pressure of ca. 35 bar to generate synthesis gas, so called syngas, which contains essentially equilibrium proportions of H_2, CO, CO_2 and H_2O.

The product gas from the reformer tubes at ca. 920°C is first cooled down to ca. 320°C in a waste heat boiler, since lower temperatures push the shift toward CO_2 and H_2. It is then fed

TABLE 1 | An overview of the investigated configurations.

Hydrogen production technology/ Configurations	Steam methane reforming (SMR)	Gas Heated Reformer (GHR)
Base Case	SMR + PCC	GHR + PCC
	CCGT (with a H-class GT) + PCC	CCGT (with an aero-derivative GT) + PCC
Integrated	H-Class GT + SMR + Steam Cycle with PCC	Aero-derivative GT + GHR + Steam Cycle with PCC
Hydrogen production	696,400 Nm^3/h (1930 MW_{LHV} H_2)	80,700 Nm^3/h (225 MW_{LHV} H_2)
Electricity generation	650 MWe	73 MWe

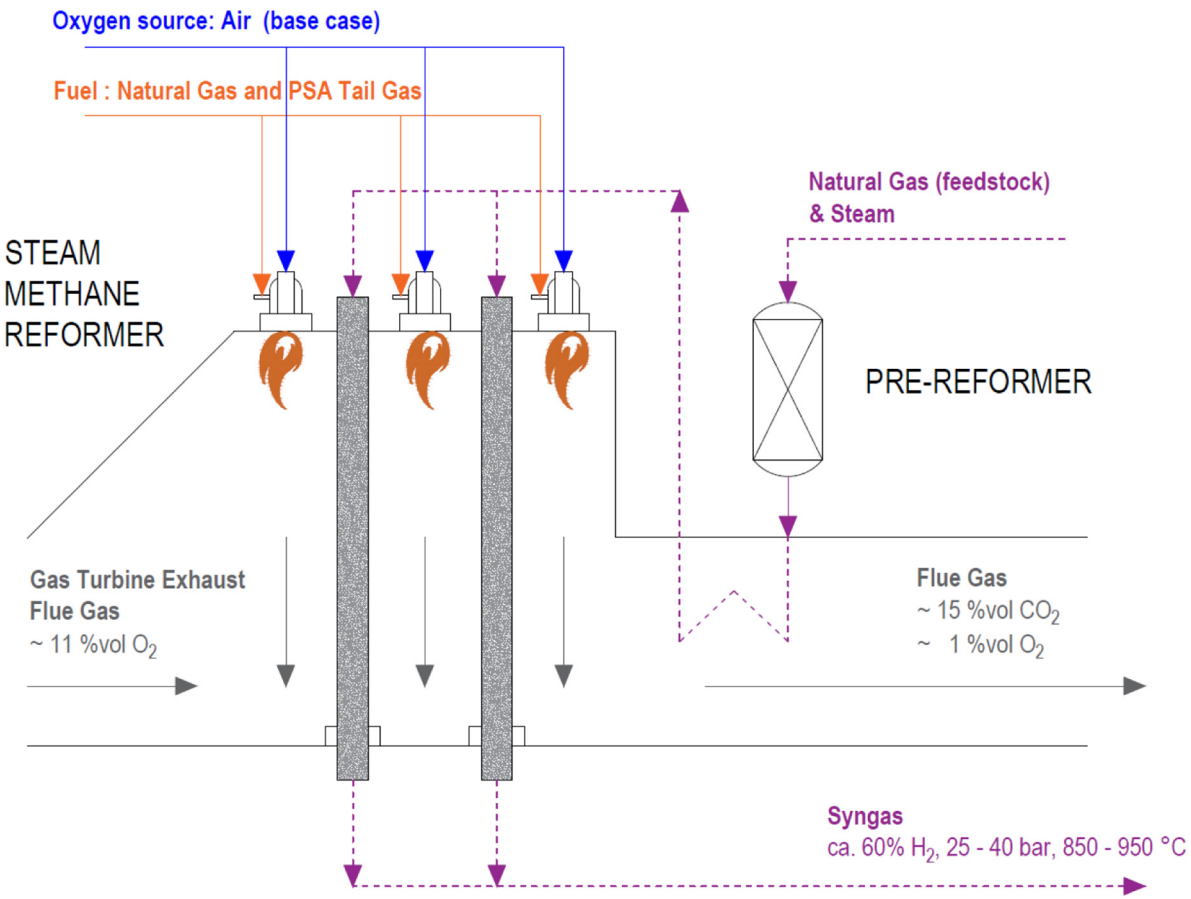

FIGURE 2 | Schematic diagram of the sequential combustion of natural gas and tail gas in a steam methane reformer furnace using the excess oxygen in a gas turbine exhaust flue gas.

to the high-temperature water-gas-shift (WGS) reactor, where steam converts most of the CO to CO_2 and H_2 over a bed of catalyst, producing a syngas with a residual CO concentration of ca. 3.6 vol%. The shifted syngas is then cooled down to ca. 35 °C, which is below its water dew point. Condensed water is recirculated back to the feed water circuit. Hydrogen is separated in the hydrogen purification unit by pressure swing adsorption (PSA) to recover typically 90% of the hydrogen at > 99.9 vol% purity. The PSA tail gas, containing mainly CH_4, CO and CO_2, is used as the primary fuel in the burners of the reformer furnace.

The flue gas leaves the reformer furnace at ca. 1260°C and sensible heat is recovered for preheating the natural gas feedstock and producing superheated steam at 400°C and 43 bar. Additional steam is generated from the syngas upstream and downstream of the WGS reactor. Part of the steam is used for the reforming process and the rest is exported to a back pressure steam turbine for electricity generation. In the steam turbine, superheated steam expands from 43 bar to 4 bar and it is then used to supply part of the reboiler duty required for solvent regeneration in the CO_2 capture system. Two independent water/steam cycles are proposed, one for the hydrogen process and one for the power cycle, due to the higher steam purity required to drive the steam turbines of the combined cycle. Importantly, this steam cycle approach would also allow operation of the gas turbine without hydrogen production and operation of the SMR, under air-firing, without the gas turbine.

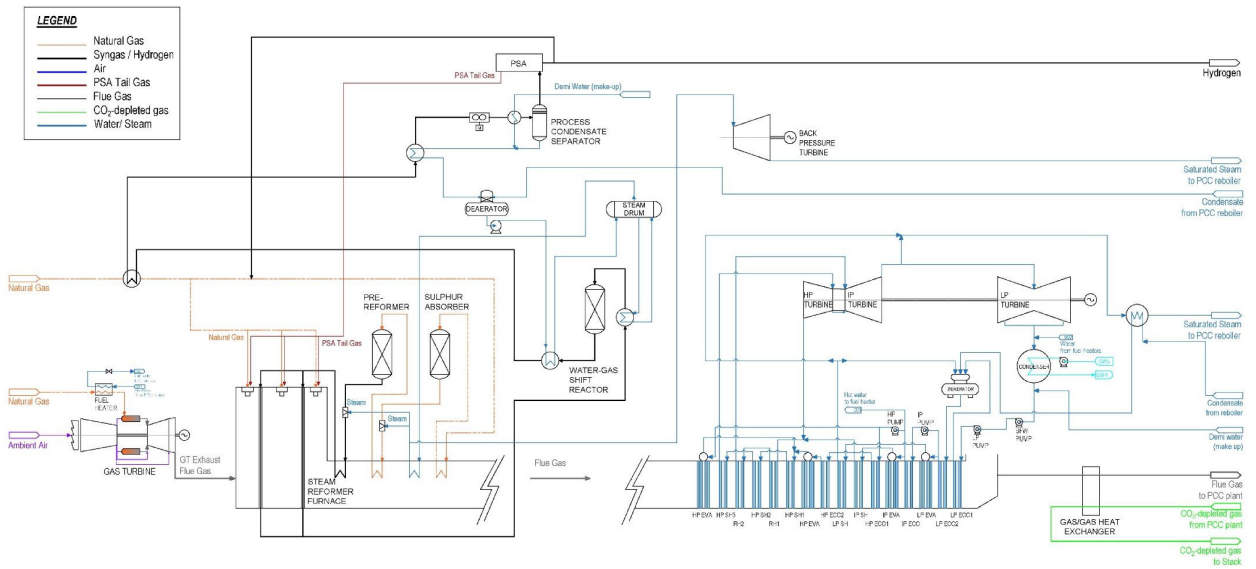

FIGURE 3 | Process flow diagram of the integrated configuration consisting of a H-class gas turbine, a steam methane reforming hydrogen plant and a steam cycle with post-combustion CO_2 capture.

The remaining heat in the exhaust flue gas is recovered in a three-pressure level HRSG with reheater located downstream of the reforming section, which supplies steam at 179 bar, 44 bar and 3.7 bar to a subcritical triple pressure steam turbine train to generate electricity.

The flue gas exiting the HRSG is cooled down first in a gas/gas rotary heat exchanger, where heat is transferred to the CO_2-depleted gas stream from the top of the absorber, and then in a direct contact cooler, entering the bottom of the absorber of the carbon capture plant at ca. 45°C saturated with water vapor.

CO_2 Capture and Compression System

The integrated configuration is equipped with a single carbon capture system to remove CO_2 from the resulting flue gas stream leaving the HRSG. One of the two carbon capture systems required in the reference configuration, i.e., one for the SMR based hydrogen plant and one for the CCGT power plant, therefore becomes redundant.

The carbon capture system consists of a conventional chemical absorption process using a 30 wt% monoethanolamine (MEA) aqueous solution as benchmark solvent for CO_2 capture processes. The thermodynamic integration of the hydrogen production and electricity generation is obviously not solvent specific or carbon capture technology specific. A detailed description of the carbon capture plant and the technical design and operational parameters are included in **Supplementary Appendix C**.

The thermal energy for solvent regeneration is provided by steam from the power plant cycle. Superheated steam is extracted between the intermediate and low pressure turbine at 3.7 bar to overcome an estimated pressure drop of 0.7 bar. The steam is conditioned and supplied to the reboiler, which is designed for saturated steam at 3 bar and 133°C, with a temperature difference of 7°C. The rest of the steam expands in the LP steam turbine to the condenser pressure at 0.038 bar. A recirculated wet cooling system is considered with a cooling water supply temperature of 15°C and a temperature rise in the cooling water return limited to 10 °C.

The CO_2-rich gas leaves the condenser at the top of the stripper column at 40°C and ca. 1.7 bar, with a CO_2 purity of 95 vol% and is conditioned prior to transport and storage/utilization to achieve a CO_2 purity of > 99 vol%. The stripper column pressure is optimized according to flue gas CO_2 content to minimize the reboiler duty for each configuration. The CO_2-rich gas stream is compressed up to the critical pressure (73.8 bar) in the compression train, which consists of three compression stages with intercooling and water separation between stages. Liquid phase CO_2 at 73 bar and 28°C is pumped to 110 bar for transport and storage in supercritical/dense phase. A detailed description of the CO_2 compression train is presented in **Supplementary Appendix D**.

Modeling Methodology

The optimization of the thermodynamic integration has the objective of minimizing the volume of the flue gas treated in the post-combustion carbon capture system and of enhancing heat recovery from the flue gas in the HRSG to maximize the steam production for power generation.

An integrated model of the power plant and the hydrogen plant equipped with CO_2 capture and compression was developed in gPROMS Model Builder (PSE, 2019). It is a process modeling platform that allows creating customized models for each unitary operation, using the property method of Peng-Robinson as equation of state for mixtures of gases and the Steam Tables (IEAPWS-95) for water and steam. The process flow diagram as implemented in gPROMS is presented in **Figure 3**.

The model of the carbon capture system based on chemical absorption with 30 wt% MEA solution is developed using gCCS library and gSAFT advanced thermodynamics to evaluate the physical properties of MEA aqueous solutions (Chapman et al., 1990, 1989; Bui et al., 2018).

A GE H-class gas turbine engine (GE 9HA.01) is considered in this work and it is modeled according to GE's design and operating specifications available in the public domain (Matta et al., 2010; General Electric Thermal Power Generation, 2019). The gas turbine operates at a pressure ratio of 23.5, a turbine inlet temperature (TIT) of 1430°C and an air fuel ratio (AFR) of 37.2 on mass basis at ISO ambient conditions and 100% load, with a mechanical power output of 446 MWe and 43.2%$_{LHV}$ thermal efficiency. The flue gas exits the gas turbine at ca. 632°C with a flow rate of ca. 850 kg/s and an oxygen concentration of 11.3 vol%, and it is used for sequential combustion of PSA tail gas and natural gas in the SMR furnace.

The model of the SMR is developed based on the technical and operating parameters of a conventional SMR described in a report commissioned by the IEAGHG (2017a), with the process modified slightly for the purpose of the thermodynamic integration with subsequent heat recovery in a three-pressure level HRSG for steam generation. The pre-reformer is simulated as an adiabatic reactor and the reformer and the water-gas-shift reactor are simulated as equilibrium reactors based on a Gibbs energy minimization approach. The SMR hydrogen plant is sized to meet the following requirements:

- The gas turbine exhaust flue gas completely replaces the combustion air and an excess oxygen of 1 vol% (wet basis) is required in the combustion gas to ensure complete combustion. The amount of natural gas burnt as auxiliary fuel in the SMR furnace is accordingly evaluated.
- The amount of natural gas feedstock is set to achieve a hydrogen production volume of ca. 696,000 Nm^3/h (16 kg/s), four times the hydrogen production volume of the SMR in the base case configuration (to match the size of the GT).
- The operating conditions in the catalytic-filled tubes are set at 912°C, with a steam to carbon ratio of 3 and a total pressure of 33.9 bar to achieve a methane conversion of 84% in the reformer (IEAGHG, 2017a). For the same values as in the base case equilibrium reactor and the same hydrogen production, the natural gas feedstock flow rate remains the same.
- A temperature of 600°C is set at the inlet of the catalytic-filled tubes. An energy balance in the furnace will define the flue gas exit temperature and therefore the pinch temperature in the reformer, defined here as the temperature difference between the process gas temperature at the inlet of the catalytic tubes, i.e., 600°C, and the furnace exit temperature.

The steam cycle downstream of the reformer section is modeled considering design and operating parameters from a study commissioned by the IEAGHG (2012). It consists of a subcritical three-pressure level HRSG, with double reheat and a screen evaporation section upstream of the high-pressure superheater and reheater surface, supplying steam to a triple pressure steam turbine. The screen evaporation section reduces the flue gas temperature down to ca. 850°C upstream of the superheater in order to maintain the tube metal temperature below acceptable limits. The pressure levels at the high, intermediate and low pressure drums are set at 179 bar, 44 bar and 3.7 bar respectively and the steam temperature to the HP and IP steam turbine cylinders is limited to 602 °C.

The CO_2 capture plant is designed and operated to achieve a generic 90% overall CO_2 capture level, i.e., 90% of the CO_2 generated in the gas turbine and in the hydrogen process as the product of the reforming reactions and the combustion of natural gas and PSA tail gas is captured from the flue gas before exiting through the stack. Although this is not the focus of this article, higher capture levels up to 95 to 99.5% could be achieve if necessary, as reported in MHI (2019).

For the purpose of the comparative performance assessment between the integrated configuration and the base case configuration, the net power output, the net thermal efficiency and the reduction in the absorber size are reported. The net power output $(\dot{W}_{net})$ and the net thermal efficiency (η_{th}) are evaluated according to Equations (1) and (2) respectively, where $\dot{W}_{GT}$ is the gas turbine power output, $\dot{W}_{BPT}$ is the back pressure turbine power output, $\dot{W}_{ST}$ is the steam turbine power output, $\dot{W}_{auxiliary}$ is the auxiliary power consumption in the feed water and cooling water pumps, $\dot{W}_{PCC}$ is the power consumption in the forced draft fan and solvent pumps of the carbon capture plant, $\dot{W}_{CO2\ compression}$ is the power consumption in the CO_2 compression train. The net thermal input takes into account the thermal energy in the natural gas streams used as fuel for the reformer burner ($\dot{Q}_{NG\ fuel\ SMR}$) and fuel for the gas turbine combustor ($\dot{Q}_{NG\ \ GT}$).

The hydrogen production efficiency (η_{H2}) used for comparing configurations is evaluated according to Equation (3), where $\dot{m}_{H2}$ is the hydrogen mass flow rate, LHV_{H2} is the low heating value of hydrogen on mass basis, and $\dot{Q}_{NG\ feedstock}$ is the thermal energy in the natural gas stream used as feedstock.

$$\dot{W}_{net} = \dot{W}_{GT} + \dot{W}_{BPT} + \dot{W}_{ST} - \dot{W}_{auxiliary} - \dot{W}_{PCC} - \dot{W}_{CO2\ compression} \tag{1}$$

$$\eta_{th} = \frac{\dot{W}_{GT} + \dot{W}_{BPT} + \dot{W}_{ST} - \dot{W}_{auxiliary} - \dot{W}_{PCC} - \dot{W}_{CO2\ compression}}{\dot{Q}_{NG\ fuel\ SMR} + \dot{Q}_{NG\ GT}} \tag{2}$$

$$\eta_{H2} = \frac{\dot{m}_{H2} \cdot LHV_{H2}}{\dot{Q}_{NG\ feedstock} + \dot{Q}_{NG\ fuel\ SMR}} \tag{3}$$

Results and Discussion

Overall Performance of the Integrated System

Since sequential combustion takes place in the burners of the reformer and the catalyst-filled tubes are located inside the flue

gas duct, the performance of the gas turbine is not affected. It operates with a mechanical power output of 446 MWe and 43.2%$_{LHV}$ thermal efficiency at ISO ambient conditions and 100% load, with the assumption that the pressure drop across the reformer is compensated by the forced draft fan of the carbon capture plant.

The steam methane reformer is, however, designed for a change in the comburent composition. The oxygen concentration in the GT exhaust flue gas is 11.3 vol%, compared to 21 vol% in ambient air. A large volume of oxygen-containing flue gas is therefore necessary to supply the amount of oxygen for complete combustion with 1 vol% excess oxygen at the exit of the furnace. This results in a relatively low firing temperature compared to that in a conventional SMR. The firing temperature decreases from 1829°C in the base case configuration to 1526°C in the integrated configuration. Consequently, the contribution of thermal radiation decreases, increasing the convective heat transfer rate. Moreover, the reformer pinch temperature, defined here as the difference between the temperature of the process gas entering the catalytic tubes and the furnace exit temperature, decreases by 100°C to 538°C. The SMR furnace requires therefore to be designed accordingly for larger heat transfer surface areas to achieve the equilibrium temperature of 912°C that leads to a methane conversion of 84%. Although this has not been studied in detail in this article, the operation of gas heated reformer in Section "A Gas-Heated Reformer Integrated With an Aeroderivative Gas Turbine Combined Cycle" suggests that this is practically achievable. **Figure 4** illustrates the flue gas temperature profile in the reforming section of the integrated configuration, which can be compared with **Supplementary Figure A.3** for the reference reformer of the base case configuration.

In order to maximize the steam generation in the HRSG, the amount of steam produced is limited to the heat recovered from the hydrogen process upstream and downstream of the WGS reactor and, thus, the amount of steam exported to the back pressure turbine is smaller than in the reference hydrogen plant. The back pressure turbine power output is ca. 20 MWe in the integrated configuration compared to 90 MWe in the base case configuration. A larger volume of flue gas enters the HRSG at a higher temperature, i.e., 920°C compared to 630°C at the exit of the gas turbine of the reference CCGT power plant, allowing for a higher steam flow rate and hence for an increase in the steam turbine power output. **Figure 5** illustrates the pinch temperature diagram in the HRSG, located immediately downstream of the SMR furnace in the integrated configuration, which can be compared with that of the HSRG of the reference CCGT power plant illustrated in **Supplementary Figure A.4.** Unlike in a conventional HRSG, a screen evaporation section is used to reduce the flue gas temperature from ca. 920°C to ca. 840°C, protecting the superheater tubes from excess temperatures.

The net power output in the integrated system is 652 MWe with a natural gas thermal input of 1673 MWth on LHV basis, which results in a thermal efficiency of 38.9%$_{LHV}$. This constitutes 34 MWe of additional power with an increase in efficiency of 4.9 perceptual points, compared to the based case configuration. Key performance parameters are presented in **Table 2**.

Effect on the CO_2 Capture System

The integrated configuration results in a single CO_2 emission source, and therefore a single carbon capture plant is required to treat the resulting flue gas stream of 970 kg/s with 14.8 vol% CO_2 and 1 vol% excess oxygen. For water saturation conditions at 45°C at the inlet of the absorber, the CO_2 concentration is 16.3 vol%, compared 10.5 vol% by mixing the two flue gas streams in the non-integrated configuration. One of the two carbon capture plants, one for the hydrogen plant and one for the CCGT power plant, in the base case configuration therefore becomes redundant, with a potential reduction in investment and operation costs associated to the CO_2 capture system. The key performance parameters of the carbon capture plant are presented in **Table 3**.

With the flue gas flow rate being approximately 34% lower than the total flow rate of the two flue gas streams from the CCGT power plant and from the SMR hydrogen plant in the base case configuration, a reduction in the absorber diameter is possible at constant gas velocity. In the integrated configuration, the capture plant comprises two absorber columns of 20 m internal diameter and 30 m packing height to operate at 80% of the flooding velocity and to achieve 90% CO_2 capture rate. It results in a packing volume of approximately 18,850 m^3, which constitutes a 17.5 vol% reduction compared to the total packing volume in the absorbers of the two carbon capture systems, i.e., one for the hydrogen plant and another for the CCGT power plant.

The high CO_2 concentration in the flue gas entering the absorber leads to a higher driving force for mass transfer and displaces the equilibrium toward a higher CO_2 loading in the rich solvent, moderately increasing the solvent capacity. Yet, according to the work of Li et al. (2011), most of the benefits occur from increasing CO_2 concentration from 4 vol% to the nominal value of 9 vol%. Compared to the capture system of the CCGT power plant of the base case configuration, the CO_2 loading of the rich solvent leaving the bottom of the absorber increases marginally from 0.480 mol_{CO2}/mol_{MEA} to 0.496 mol_{CO2}/mol_{MEA} in the integrated configuration. The optimal lean loading minimizing reboiler duty is 0.262 mol_{CO2}/mol_{MEA}. The moderate increase in solvent capacity and the lower solvent flow results in a reduction of the specific reboiler duty of approximately 4.3%, from 3.26 GJ/tCO_2 in the capture plant of the CCGT power plant, to 3.12 GJ/tCO_2, in the capture plant of the integrated configuration.

A GAS-HEATED REFORMER INTEGRATED WITH AN AERODERIVATIVE GAS TURBINE COMBINED CYCLE

A gas heated reformer or convective steam reformer is a compact alternative to the conventional bottom, top, terrace wall or side fired steam reformer furnaces for the production of synthesis gas from natural gas. Convective reformers were developed to improve the energy efficiency and reduce the investment costs due to their compact design and modularization, and

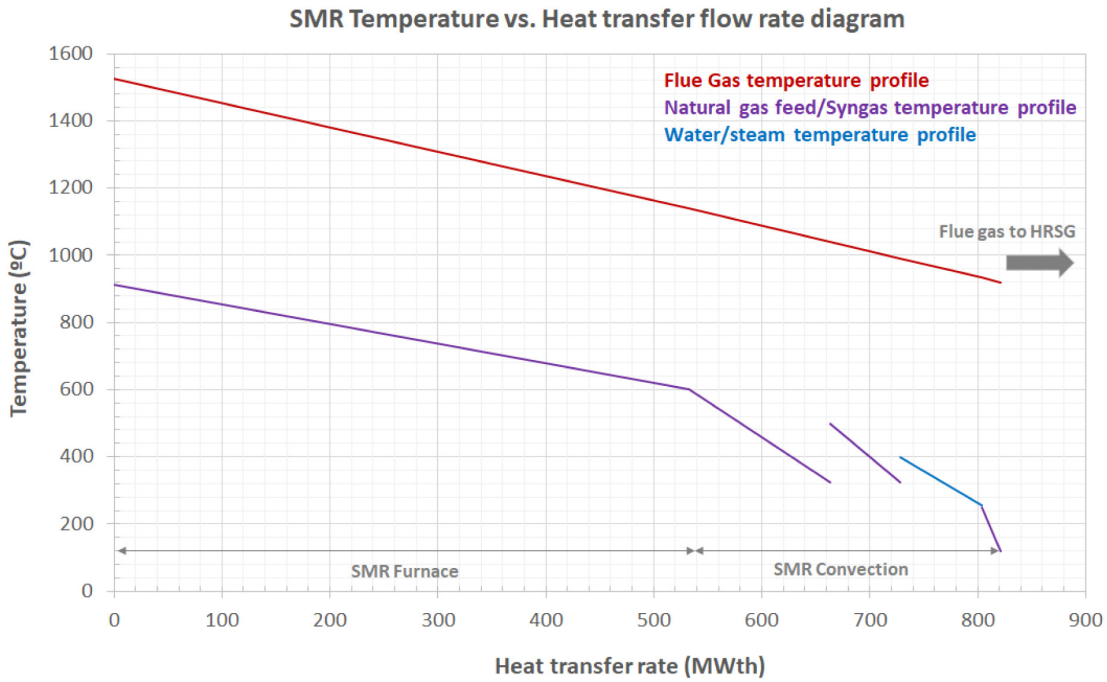

FIGURE 4 | Temperature vs. heat transfer flow rate diagram in the steam methane reforming of the integrated GT-SMR-HRSG configuration.

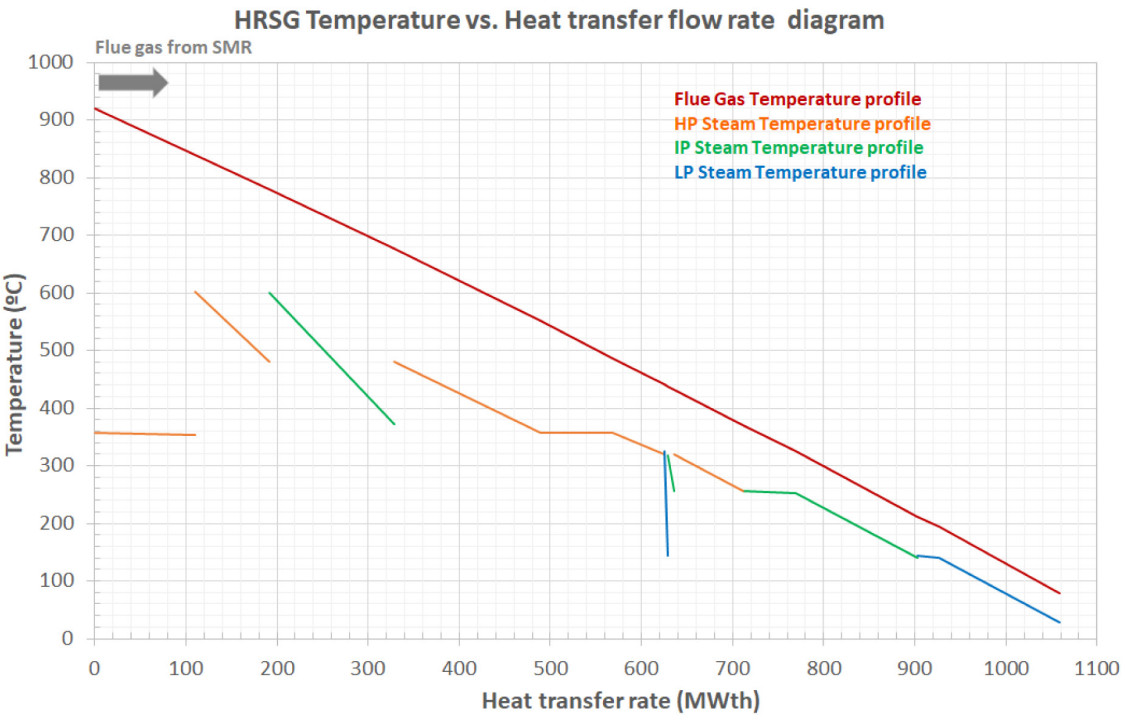

FIGURE 5 | Temperature vs. heat transfer flow rate diagram in the heat recovery steam generation section of the integrated GT-SMR-HRSG configuration.

they are preferred for smaller capacities up to 50,000 Nm^3/h (Wesenberg et al., 2007). Thermal convection is the dominant heat transfer mechanism in the tubular reactor and, thus, the results of integration with a CCGT power plant are of particular interest. For the purpose of this study, the use of a GHR allows a wider range of hydrogen production capacities to be

TABLE 2 | Performance parameters of the integrated system consisting of a steam methane reformer downstream of a H-class gas turbine and of the hydrogen plant and the CCGT power plant of the base case configuration.

Hydrogen technology:		**Steam Methane Reformer (SMR)**		
Configuration:		**H_2 Plant**	**Power Plant**	**Integrated system**
		SMR + PCC	H-class GT + SC + PCC	H-class GT + SMR + SC + PCC
Hydrogen production				
H_2 production	Nm^3/h	692920	–	696366
H_2 production	kg/s	16.0	–	16.1
Total energy in product	MWth	1919.4	–	1928.9
Natural gas (feedstock) flow rate	kg/s	47	–	48
H_2 production efficiency	%	64.8	–	66.6
Power generation				
Gas Turbine power output	MWe	–	446.0	446.0
Back pressure turbine power output	MWe	89.8	–	20.1
Steam turbine power output	MWe	–	161.8	270.9
Feed water pumps power consumption	MWe	–	2.9	5.9
Booster fan power consumption	MWe	3.3	4.8	11.5
Solvent pumps power consumption	MWe	0.5	0.2	1.9
CO_2 compression train power consumption	MWe	50.7	17.9	66.3
Net power output	**MWe**	**35.2**	**582.0**	**651.5**
Additional power output	MWe			34.3
Thermal input - NG fuel	MWth	782	1033	1673
Net thermal efficiency	**%**	**3**	**56.58**	**38.93**
Overall thermal efficiency	**%**	34.00		38.93
Fuel Thermal input				
Natural gas fuel to SMR	kg/s	15	–	14
Natural gas fuel to GT	kg/s	–	22.23	22.23
Additional fuel	kg/s			−1.51

explorer, with the use of different gas turbine engines in the integrated configuration.

Gas heated reformers are designed and sized to maximize the hydrogen yield whilst minimizing the fuel consumption and the steam production. The integration of a stand-alone GHR with a post-combustion carbon capture system using flue gas scrubbing technology would therefore require an external source of steam to provide the heat for solvent regeneration.

Process Description of the GHR Based Hydrogen Plant and the CCGT Power Plant Equipped With CO_2 Capture

GHR Hydrogen Process and CCGT Power Plant

The process flow diagram of the integrated configuration consisting of a conventional gas heated reformer (GHR), as illustrated in **Figure 6**, located downstream of a commercially available aeroderivative gas turbine. The integrated system is illustrated in **Figure 7**. The hydrogen plant procures ca. 80,750 Nm^3/h (1.86 kg/s) of H_2 at 25 bar and 35°C. As previously discussed, the gas turbine exhaust flue gas is used as the source of oxygen for the combustion of tail gas from the hydrogen purification unit, as primary fuel, and natural gas, as auxiliary fuel, replacing the combustion air in the burners of the reformer combustion chamber. The combustion gas at approximately 1200°C then enters the convective reformer which consists of a multi-tubular reactor where heat is mainly transferred by convection from the hot flue gas stream to the catalyst-filled tubes, as shown in the schematic diagram of **Figure 6**. Unlike in the furnace of a fired SMR, convective heat transfer is the dominant form of heat transfer in the reactor.

The heat released in the combustion supplies the sensible heat required to increase the natural gas feedstock temperature up to the equilibrium temperature of approximately 850°C and the heat for the endothermic reforming reactions. The remaining sensible heat in the flue gas is used first to pre-heat the feed stream containing natural gas and steam and then to generate steam for power generation in an HRSG located downstream of the convective reformer. Superheated steam is supplied to a double pressure steam turbine generator at 54 bar and 3.7 bar. Unlike H-class gas turbines, aeroderivative gas turbines are typically integrated with a two-pressure level HRSG since the smaller power output drives the economics toward a lower capital cost system.

With the exception of possible changes in the combustion taking place in the burner of the combustion chamber, the remaining of the hydrogen process is consistent with an air-fired conventional gas heated reformer of the base case configuration described in **Supplementary Appendix B.1.** A desulfurized and pre-heated natural gas stream is mixed with steam. The steam flow rate is set to achieve a steam to carbon ratio of 3 in the reformer feed to avoid thermal cracking of the hydrocarbons and

TABLE 3 | Performance parameters of the carbon capture plant of the integrated system and of the hydrogen plant and the CCGT power plant of the base case configuration.

Hydrogen technology		**Steam Methane Reformer (SMR)**		
Configuration		**H_2 Plant**	**Power Plant**	**Integrated system**
		SMR + PCC	H-class GT + SC + PCC	H-class GT + SMR + SC + PCC
Carbon capture plants no.		1 PCC plant	1 PCC plant	1 PCC plant
Solvent		30 wt% MEA	30 wt% MEA	30 wt% MEA
Overall CO_2 capture level	%	90.0	90.0	90.0
Absorber				
Flue gas flow rate [1]	kg/s	624.6	848.9	971.2
CO_2 concentration [1]	vol%	17.96	4.50	14.81
CO_2 concentration BOT [2]				
CO_2 concentration TOP	vol%	1.80	0.45	1.48
Lean solvent flow rate	kg/s	2369.4	1102.1	4094.4
Rich solvent CO_2 loading	molCO_2/molMEA	0.496	0.480	0.497
Lean solvent CO_2 loading	molCO_2/molMEA	0.262	0.264	0.262
Solvent capacity	molCO_2/molMEA	0.234	0.216	0.235
Stripper Column				
Stripper pressure	Bar	1.79	1.79	1.79
Steam specific consumption	kg/kg CO_2	1.42	1.49	1.43
Sp. Reboiler duty	GJ/tCO_2	3.12	3.26	3.12
CO_2 compression train				
CO_2 flow rate to pipeline	kg/s	159.9	54.5	220.0
Specific compression work	kWh/kgCO_2	92.85	93.31	92.85
Power consumption	MWe	13.08	35.84	22.98
Packing dimensions				
Absorber packing volume	m^3	11146	11690	18850
Number of absorbents	–	1	2	2
Stripper packing volume	m^3	1963	1018	3578
Number of stripper columns	–	1	2	2

Note [1]: CO_2 concentration and flow rate upstream the direct contact cooler of the capture plant. Note [2]: CO_2 concentration for saturation conditions at 45°C.

coke formation. The mixture of natural gas and steam is further preheated and enters the gas heated reformer at ca. 450°C, flows downward through the catalyst bed and reaches equilibrium at the bottom of the reactor. The reformed gas enters the center tube and continues upward leaving the reactor at ca. 600°C to enter the heat recovery section.

In the air-fired GHR of the base case configuration, a methane conversion of 73% is possible with a steam to carbon ratio of 3, an equilibrium temperature of 850°C and a total pressure of 33.9 bar. The introduction of sequential combustion requires modifications to the process to accommodate for changes in the composition of the comburent with a higher CO_2 and H_2O concentration than in ambient air. The reactor is therefore designed for the same carbon ratio and total pressure, yet for a lower equilibrium temperature of ca. 815°C. A lower equilibrium temperature leads to a lower methane conversion, shifting the chemical equilibrium, which leads to a higher volume of recycled PSA tail gas with a higher calorific value sent to the burner of the GHR. Although this lowers the specific hydrogen production per unit of volume of fuel, it has the advantage of increasing the steam generation and meet the steam requirements in the capture system for high CO_2 capture rates.

The product gas from the steam reformer, containing equilibrium amounts of H_2, CO_2, CO and CH_4, is then cooled down and fed to the WGS reactor where steam converts most of the CO to CO_2 and H_2 over a bed of catalyst, producing a syngas with a residual CO concentration of ca. 1 vol%. The raw hydrogen steam is fed to the hydrogen purification system by PSA to recover typically 90% of the hydrogen at > 99.9% purity. The PSA tail gas, containing mainly CH_4, CO_2 and CO, is recirculated to be used as the primary fuel in the combustion chamber.

Sensible heat is recovered from the reformed gas stream upstream and downstream of the WGS reactor to produce saturated steam at 42.3 bar and 254°C. The waste heat recovery system is typically designed to produce only the steam required for the reforming reactions, unlike in a conventional steam methane reformer where more steam is produced for co-generation. Equipped with carbon capture, a stand-alone hydrogen plant with a GHR would therefore need to import steam or to generate team on-site in an ancillary boiler or a combined heat and power (CHP) plant.

CO_2 Capture and Compression System

The CO_2 capture system and compression train are size according to the flow rate of combustion gas and CO_2 flow, using the principles described in Section "CO2 Capture and Compression System." The reader is referred to Appendices C and D for further details and relevant design and operational parameters.

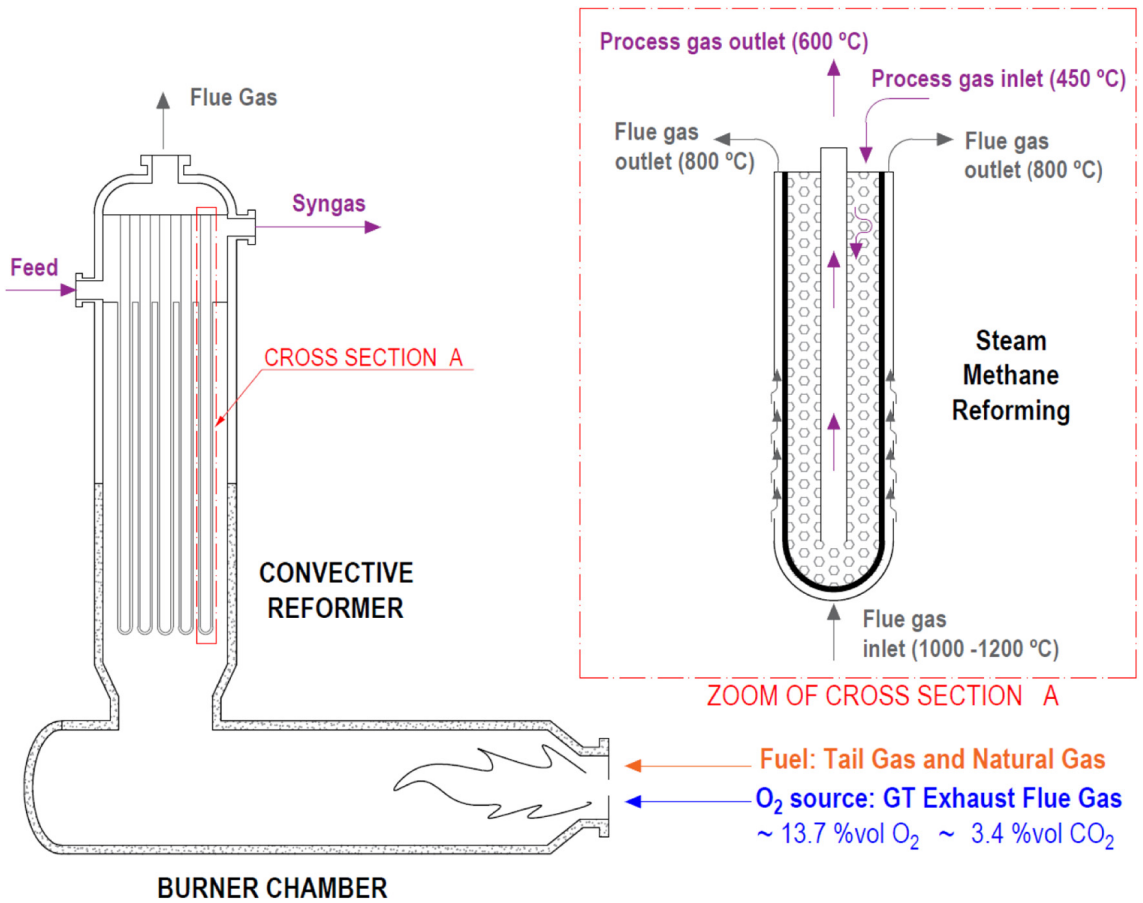

FIGURE 6 | Schematic diagram of the gas heated reformer in the integrated configuration.

Modeling Methodology

Customized models for each unit of the integrated gas heated reformer are developed in gPROMS Model Builder (PSE, 2019) using the library and the thermodynamic models described in Section "Modeling Methodology." The process flow diagram as implemented in gPROMS is presented in **Figure 7**.

The model of the GHR reformer is based on the technical and operation specifications reported in a Haldor Topsøe's report for the 6,000 Nm^3/h Topsøe low-energy HTCR hydrogen plant at BorsodChem MCHZ's facilities in Ostrava in the Czechia (Haldor Topsoe, 2007). The reformer and the WGS reactor are simulated as equilibrium reactors based on Gibbs energy minimization approach.

The gas turbine upstream of the gas heated reformer is a GE's LM6000 aeroderivative gas turbine modeled according to GE's design and operation specifications available in the public domain (Badeer, 2000; General Electric Thermal Power Generation, 2017). The gas turbine engine operates at a pressure ratio of 30, a turbine inlet temperature (TIT) of 1250°C and an air fuel ratio (AFR) of 50 on mass basis at ISO ambient conditions and 100% load, with a power output of 57 MWe and a thermal efficiency of 42.6%$_{LHV}$. An exhaust flue gas flow rate of 148 kg/s, exiting the gas turbine at 490°C and with oxygen concentration of 13.7 vol%, is used as the source of oxygen for the combustion of PSA tail gas and natural gas in the combustion chamber of the GHR.

The size and flow rate of the GE LM 6000 is compatible with the mass balance and energy balance of sequential combustion in the combustion chamber and the reactor of a gas heated reformer. An energy balance in the reformer allows to determine the maximum possible hydrogen production of ca. 80,750 Nm^3/h (1.86 kg/s), and the performance comparison with the air-fired GHR in the base case configuration is conducted on the basis of the same hydrogen production capacity.

The steam cycle is modeled on the basis of design parameters from the report commissioned by the IEAGHG (2012). As previously discussed, the shared carbon capture system in the integrated configuration is sized for a 90% CO_2 capture rate.

Key Metric for Comparative Assessment With the Base Case Air-Fired GHR Hydrogen Plant With CO_2 Capture

Since the gas heated reformers are designed to minimize steam production, they are not particularly suited for CO_2 capture as stand-alone units, unless an external source of steam provides heat for the solvent regeneration. In the base case configuration with an air-fired GHR, steam is generated from

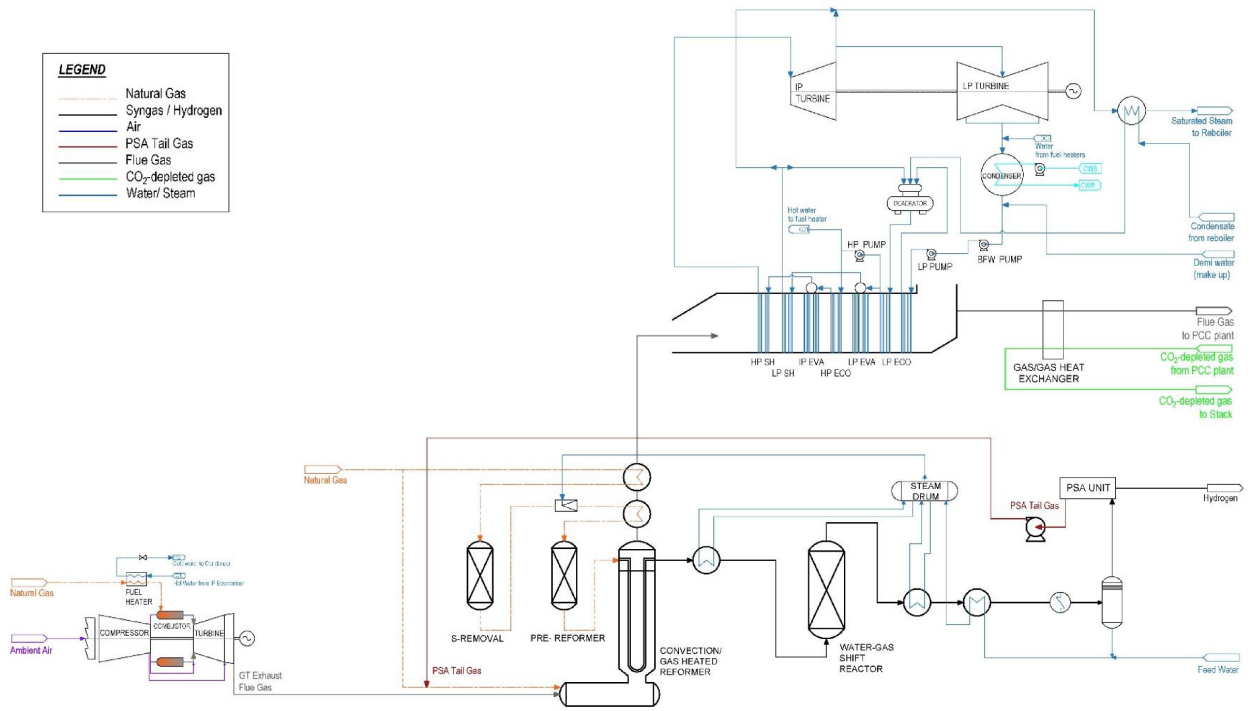

FIGURE 7 | Process flow diagram of the integrated configuration consisting of an aeroderivative gas turbine, a gas heated reformer and a steam cycle with post-combustion capture.

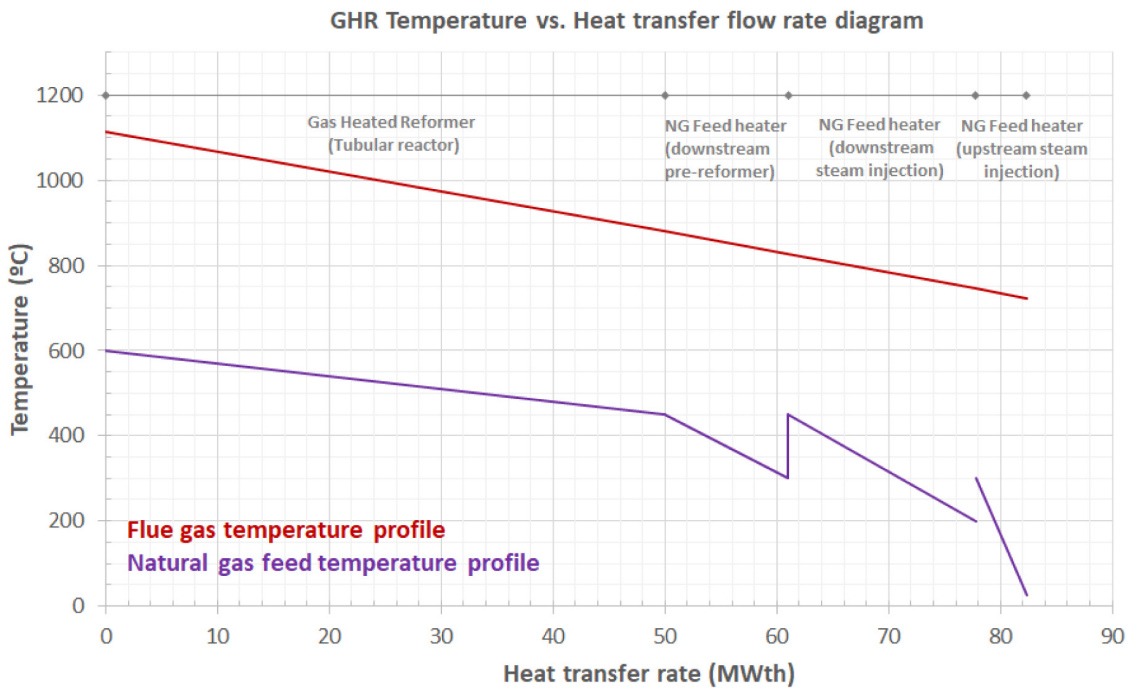

FIGURE 8 | Temperature vs. heat transfer flow rate diagram in the reformer of the integrated configuration consisting of a aeroderivative gas turbine and a gas heated reformer, for 90% CO_2 capture level in the post-combustion carbon capture system.

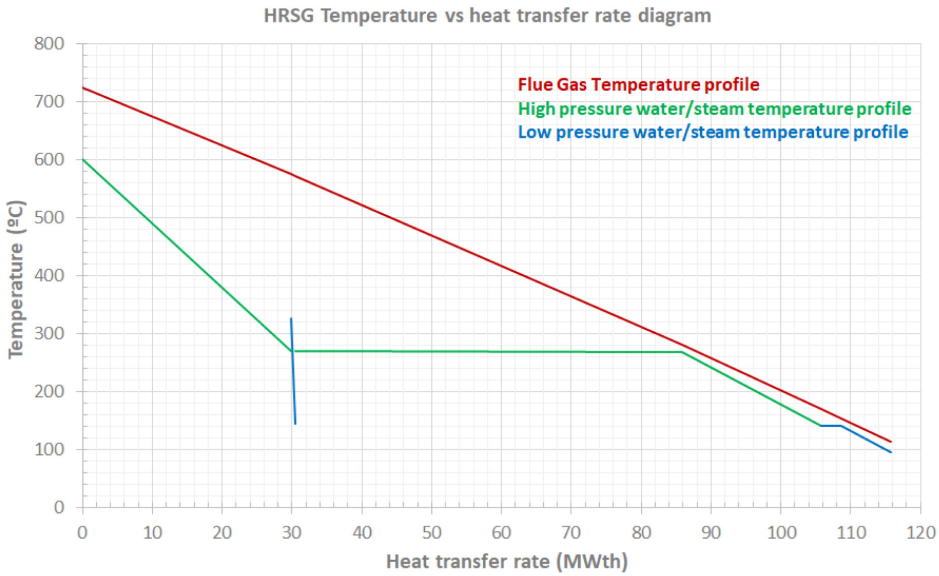

FIGURE 9 | Temperature vs. heat transfer flow rate diagram in the heat recovery steam generation section of the integrated configuration consisting of a aeroderivative gas turbine and a gas heated reformer, for 90% CO_2 capture level in the post-combustion carbon capture system.

heat recovery from the flue gases, yet additional steam extraction from the combined cycle is needed. Steam extraction from the combined cycle therefore supplies the thermal energy for the two carbon capture plants.

Limited steam availability in the combined cycle results in an overall CO_2 capture rate of 84.5%. In this instance, the absorber columns are respectively sized for 90% capture rate from the CCGT flue gas and 82% capture rate from the GHR flue gas, although other permutations would be possible. The overall CO_2 capture rate is also directly determined by the size of the aeroderivative gas turbine and the hydrogen production volume, 57 MWe and 80,750 Nm^3/h in this case. The reader is referred to **Supplementary Appendices B.1, B.2** respectively for all relevant details on the technical design and operating parameters of the hydrogen plant and the CCGT power plant equipped with their respective carbon capture systems in the base case configuration.

Results and Discussion

Overall Performance of the Integrated System

Since the aeroderivative gas turbine is located upstream of the GHR, the operation of the gas turbine is unaffected and operates with a power output of 57 MWe and 42.6%$_{LHV}$ thermal efficiency at ISO ambient conditions and 100% load, with, as previously stated, the assumption that the additional pressure drop in the reformer is compensated by the forced draft fan of the carbon capture plant.

The design and operation of the GHR deviates, however, from the design conditions for air-firing. The relatively low oxygen concentration in the GT exhaust flue gas, i.e., 13.7 vol% compared to 21 vol% in ambient air, results in a large volume of flue gas to supply the amount of oxygen needed for complete combustion of the PSA tail gas and natural gas, and to ensure flame stability. Unlike SMRs were the excess oxygen level is as low as 1 vol%, gas heated reformers operate with much higher excess air resulting in a 8 vol% excess oxygen at the exhaust, as indicated in **Supplementary Appendix B.1**. With sequential combustion, the excess oxygen at the exit of the GHR combustor chamber is ca. 6.7 vol%.

Due to the large volume of flue gas, the combustion chamber exit temperature and, thus, the temperature of the combustion gas entering the convective reformer is lower than 1200°C, i.e., the combustor exit temperature in a stand-alone GHR with air-firing. This results in a lower equilibrium temperature in the reformer for a given heat transfer area and a given pinch temperature, defined here as the difference between the combustion gas temperature and the equilibrium temperature. Although the lower equilibrium temperature shifts the equilibrium toward a lower hydrogen yield, the content of unreacted methane in the PSA tail gas increases, raising the fuel heating value and thus the temperature of combustion.

Ultimately, the operating conditions and the reactor equilibrium temperature are optimized so that enough steam is produced in the HRSG to achieve a CO_2 capture rate of 90% for a hydrogen production of ca. 80,750 Nm^3/h. Using as the comburent the gas turbine flue gas with an exhaust flue rate of 148 kg/s and an excess oxygen of 13.5 vol%, the GHR operates at a combustion gas temperature of 1115°C and an equilibrium temperature of 815°C. The relatively small pinch temperature of 300°C would require increasing the heat transfer area compared to an air-fired GHR with a pinch temperature of 350°C. Due to the smaller methane conversion in the catalytic tubes, the natural gas flow rate used as feedstock increases from 5.9 kg/s to 6.6 kg/s.

Sequential combustion of additional fuel in a GT exhaust flue gas also leads to a higher temperature of the flue gas entering

TABLE 4 | Performance parameters of the hydrogen plant with a gas heated reformer and the CCGT power plant for both the base case configuration and the integrated configuration.

Hydrogen technology		**GAS HEATED REFORMER**			
Configuration		**H_2 plant**	**Power plant**	**Integrated**	**Integrated**
		GHR + PCC	CCGT with aero-GT + PCC	aero GT + GHR + SC + PCC 84.5% CO_2 capture rate	aero GT + GHR + SC + PCC 90% CO_2 capture rate
Hydrogen production					
Hydrogen production	Nm^3/h	80749	–	80749	80749
Hydrogen production	kg/s	1.86	–	1.86	1.86
Total Energy in product	MWth	224	–	224	224
NG Feedstock flow rate	kg/s	5.90	–	6.59	6.59
H_2 production efficiency [1]	%	78.91	–	70.56	70.56
Power generation					
Gas Turbine power output	MWe	–	57.00	57.00	57.00
Steam turbine power output	MWe	–	8.65	27.91	26.62
Feed water pumps power consumption	MWe	–	0.11	0.24	0.24
Booster fan power consumption	MWe	0.49	0.83	0.90	0.90
Solvent pumps power consumption	MWe	0.07	0.03	0.11	0.11
CO_2 compression train power consumption	MWe	–	6.78	7.31	7.79
Net power output	**MWe**	**0**	**57.34**	**76.36**	**74.59**
Additional power output	*MWe*	–	–	*19.01*	–
Thermal input - NG fuel	MWth	23.59	133.76	146.92	146.92
Net thermal efficiency [2]	**$\%_{LHV}$**	**0**	**42.87**	**57.09**	**55.76**
Overall thermal efficiency [2]	*$\%_{LHV}$*	*39.51*		*57.09*	*55.76*
Fuel thermal input					
NG Fuel to GHR flow rate	kg/s	0.24	–	0.24	0.24
NG Fuel to GT flow rate	kg/s	–	2.88	2.88	2.88
Additional fuel	*kg/s*	–	–	0	0
Carbon capture system					
Flue gas flow rate	kg/s	77.74	147.73	162.21	162.21
Flue gas CO_2 concentration	%vol CO_2	14.06	3.37	10.41	10.41
Steam from combined cycle	kg/s	0	20.15	35.54	35.54
Steam to PCC reboiler	kg/s	9.64	20.15	31.21	33.24
CO_2 capture level	%	81.86	90.00	84.50	90.00
Overall CO_2 capture level	%	84.5		84.5	90.0
Reboiler duty	GJ/tCO_2	3.17	3.36	3.17	3.17
CO_2 flow rate to pipeline	kg/s	13.35	6.92	22	23.3

Note [1] Hydrogen production (MWth)/thermal input as NG fuel and NG feedstock (MWth). Note [2] Electrical power output (MWe)/thermal input as NG fuel to both the GT burner and the GHR burner (MWth).

the heat recovery section. The flue gas enters the HRSG at ca. 724°C, increasing the rate of steam flow and hence the steam turbine power output. The maximum steam temperature is, however, limited to a typical 600°C at the inlet of the high pressure steam turbine cylinder. The temperature profile along the flue gas pathway is illustrated in **Figures 8**, **9**. **Figure 8** shows the temperature pinch diagram of the reformer and **Figure 9** shows the temperature pinch diagram of the heat recovery steam generator. For a hydrogen production of ca. 80,750 Nm^3/h and 90% overall CO_2 capture rate, the integrated configuration of a GHR and a CCGT with an aeroderivative gas turbine operates at 73 MWe power output and presents a thermal efficiency of 54.7%$_{LHV}$. Key performance parameters are included in **Table 4**.

In order to conduct the comparative performance assessment on a consistent basis, two cases of the integrated configuration are reported in **Table 4**. The first case operates at an overall CO_2 capture rate of 84.5%, i.e., identical to the highest possible capture rate achievable in the base case configuration using the remaining steam from the CCGT power plant. This level of capture is unlikely to be acceptable and is used solely for the purpose of a rigorous comparison on the basis of capture levels. The second case achieves a nominal 90% CO_2 capture rate.

For the overall CO_2 capture rate of 84.5%, the integrated configuration presents a higher net power output of 76.4 MWe due to the increase in the steam turbine power output, and a higher net thermal efficiency of 57.1%$_{LHV}$, compared to

TABLE 5 | Performance parameters of the shared CO_2 capture system for a hydrogen plant with a GHR and a CCGT with an aeroderivative gas turbine.

Hydrogen technology		**GAS HEATED REFORMER**
Configuration		**Integrated aeroderivative GT + GHR + SC**
Solvent		30 wt% MEA aq
Overall CO_2 capture level	%	90.0
Flue gas flow rate (to DCC)	kg/s	162.2
CO_2 concentration (to DCC)	vol%	10.41
Absorber		
Flue gas flow rate sat @ 45°C	kg/s	157.9
CO_2 conc. - bottom	%vol	10.88
CO_2 conc. - top	%vol	1.21
Lean solvent flow rate	kg/s	445.5
Solvent to gas ratio	–	2.9
Rich solvent CO_2 loading	molCO_2/molMEA	0.488
Lean solvent CO_2 loading	molCO_2/molMEA	0.263
Solvent capacity	molCO_2/molMEA	0.225
Stripper Column		
Stripper pressure	bar	1.79
Steam specific consumption	kg/kg CO_2	1.45
Sp. Reboiler duty	GJ/tCO_2	3.17
CO_2 compression train		
CO_2 flow rate to pipeline	kg/s	23.3
Specific compression work	kWh/kgCO_2	93.31
Power consumption	MWe	7.79
Packing dimensions		
Absorber packing volume	m^3	1543
Number of absorbents	–	1
Stripper packing volume	m^3	475
Number of stripper columns	–	1

57.3 MWe and 39.5%$_{LHV}$ in the base case configuration. Key parameters for the performance assessment comparison of the two configurations are presented in **Table 4**.

In the integrated system with sequential combustion and 90% capture, the hydrogen production is ca. 80,750 Nm^3/h, the power output is 74.6 MWe and the net thermal efficiency is 55.8%$_{LHV}$. An increase in natural gas feedstock flow rate of ca 10% reduces the H_2 production efficiency in the integrated system. The increase is necessary to increase steam production in the HRSG to provide additional low-pressure steam for the capture plant. This is achieved by a reduction of the equilibrium temperature in the reformer, making unreacted CH_4 available in the tail gas from hydrogen production in the fuel to the GHR combustion chamber and enhancing the heat recovery from the exhaust flue gas at a higher temperature for steam generation.

Effect on the CO_2 Capture System

Since the integrated configuration results in a single CO_2 emission source, a single carbon capture plant is required to treat the resulting flue gas stream of 162 kg/s with 10.4 vol% CO_2 and 6.7 vol% excess oxygen. Similarly to the thermal integration explained in Section "Results and Discussion," the flow rate of the resulting flue gas with sequential combustion is therefore 28% smaller than in the base case configuration and the integration allows for a smaller total cross-section of the absorber in the capture plant.

The CO_2 concentration in the flue gas is higher than the concentration that would result from mixing the two flue gas stream from the gas turbine engine and the reformer, i.e., 10.9 vol% CO_2 compared to 6.9 vol% CO_2 for a flue gas saturated at 45°C. It allows operation at a higher rich solvent loading of 0.49 mol_{CO2}/mol_{MEA}, resulting in a moderately higher solvent working capacity of 0.225 mol_{CO2}/mol_{MEA}. The specific reboiler duty is ca. 3.17 GJ/t_{CO2}, similar to that in the capture plant for the GHR of the base case configuration, which is supplied by steam extracted from the combined cycle.

The technical design and operation parameters of the carbon capture system of the integrated configuration for a 90% overall CO_2 capture rate are presented in **Table 5**. In addition to an increase of 19% net power output at constant hydrogen production, the other major benefit of the integrated configuration for a GHR is that a nominal 90% CO_2 capture rate is now achievable unlike a much lower 84.5% capture rate without sequential combustion.

CONCLUSION

Sequential combustion of natural gas in the exhaust flue gas of a gas turbine is proposed for the first time in this work to reduce the capital and operating cost of post-combustion CO_2 capture (PCC) in hydrogen production via steam methane reforming integrated with in electricity generation using combined cycle gas turbine (CCGT) power plants.

Effective thermodynamic integration significantly increases net power output in at constant hydrogen production volume, reducing operating costs, whilst the use of a shared CO_2 capture system is expected to contribute to significant capital cost reduction.

A newly developed rigorous model in gPROMS of gas turbine power generation systems integrated with examples of two hydrogen production technologies quantifies the step change in thermal efficiency and hydrogen production efficiency. It uses a conventional 30 wt% MEA capture process as a generic capture technology to quantify the reduction in size of absorber columns, the most capital intensive part of solvent-based post-combustion capture systems. The thermodynamic integration of sequential combustion between hydrogen production and power generation is, however, not solvent specific or capture technology specific and are applicable to other processes of post-combustion CO_2 capture.

Two hydrogen production technologies, a conventional steam methane reformer (SMR) and a gas heated reformer (GHR), cover a wide range of hydrogen capacities, and in the example cases these are thermodynamically integrated with standard commercially available gas turbine engines, selected on the basis of their exhaust gas flow rate. When sequential combustion of natural gas, mixed with the tail gas from hydrogen separation,

in the gas turbine exhaust gas takes place in the burner of the reformers, a single CO_2 emission source with significantly lower flow rates by 34%, in the SMR, and by 28%, in the GHR, reduces the number of absorber columns compared to equivalent non-integrated systems. In addition, the flow rate and the temperature of the flue gas entering the heat recovery steam generator (HRSG) increase, leading to additional steam production for electricity generation.

The conventional SMR is located downstream of an H-class gas turbine engine followed by a three-pressure level HRSG, supplying steam for power generation in the combined cycle, and a capture plant with two absorber columns. The integrated system produces ca. 696,400 Nm^3/h of H_2 with a net power output of 652 MWe at a net thermal efficiency of $38.9\%_{LHV}$. This corresponds to 34 MWe of additional power output, increasing efficiency by 4.9% points, and makes one absorber column redundant, compared to the equivalent non-integrated system producing the same volumes of H_2. A CO_2 concentration of 15 vol% allows effective operation of the 30 wt% MEA capture process at high solvent capacity, resulting in a reduction of absorber structured packing volume of 18% and a lower thermal energy for solvent regeneration by 4.3%.

The dedicated GHR is located downstream of an aeroderivative gas turbine engine followed by a two-pressure level HRSG, supplying steam for power generation in the combined cycle, and capture plant with one absorber column. The integrated system produces ca. 80,750 Nm^3/h of H_2 with a net power output of 73 MWe and a net thermal efficiency of $54.7\%_{LHV}$. This corresponds to 13 MWe of additional power output, increasing efficiency by 13.5% points, and reduces the number of absorber columns necessary from two to one, compared to the equivalent non-integrated system producing the same volumes of H_2.

The article also presents new insights for the design and operation of reformers integrated with gas turbines. First, sequential combustion enables additional steam production in the gas turbine/GHR system to achieve CO_2 capture rates of 90%, or higher if necessary, compared to 84.5% in the equivalent non-integrated system. This is achieved by lowering the reactor temperature to increase the non-reacted methane concentration in the recirculated tail gas. Second, the operation of the gas turbine engine is unaffected since sequential combustion takes place in the reformer furnace or combustion chamber. This would make operating the gas turbine, HRSG and capture when the reformer is turned off possible.

The reformer is, however, designed for a change in the comburent composition and, in the case of a SMR, an increase of convective heat transfer rate over the radiative heat transfer rate. The lower oxygen concentration in the gas turbine exhaust flue gas, i.e., 11.3 vol% in a H-class gas turbine and 13.7 vol% in an aeroderivative gas turbine, compared to 21 vol% in ambient air, results in larger flow rates to supply the necessary amount of oxygen. This leads to a lower firing temperature and, thus, a smaller pinch temperature in the reformer, reducing the driving force for heat transfer. A large heat transfer surface area is likely to be required in the catalytic tubes of the reformer to maintain the equilibrium temperature at the design values and achieve a high hydrogen yield. Further work would be required to examine the operation of the reformer and the capture plant when the gas turbine is turned off.

These are important design considerations, to allow for flexible operating strategies for the generation of low-carbon hydrogen independently of low-carbon electricity, and vice-versa, when it makes economic sense to do so. Designing for flexible operation could be used to achieve further cost reduction via an increase of the utilization factor of the CO_2 capture plant, since in future energy systems, seasonal variation in demand for hydrogen may indeed follow, to some extent, the seasonal patterns currently observed for natural gas, whilst electricity is expected to continue to be traded as a volatile commodity on a daily or hourly basis.

DATA AVAILABILITY STATEMENT

All datasets generated for this study are included in the article/**Supplementary Material**.

AUTHOR CONTRIBUTIONS

JG, ML, and LH conceived the present idea. LH developed the model and performed the simulations and wrote the manuscript with support from ML and HC. ML and JG contributed to the discussion of the results and the findings. ML, JG, and HC contributed to the final manuscript. All authors provided critical feedback and helped shape the research, analysis and manuscript.

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The BECCS Implementation Gap –A Swedish Case Study

Sabine Fuss[1,2,3]* *and Filip Johnsson*[2]

[1]*Mercator Research Institute on Global Commons and Climate Change, Berlin, Germany,* [2]*Department of Space, Earth and Environment, Chalmers University of Technology, Göteborg, Sweden,* [3]*Geographisches Institut, Humboldt-Universität Zu Berlin, Berlin, Germany*

The IPCC has assessed a variety of pathways that could still lead to achievement of the ambitious climate targets set in the Paris Agreement. However, the longer time that climate action is delayed, the more the achievement of this goal will depend on Carbon Dioxide Removal (CDR) technologies and practices. In the models behind these pathways, the main CDR technology is Bioenergy combined with Carbon Capture and Storage (BECCS). We review the role that BECCS could play in reaching net-zero targets based on the existing 1.5°C scenarios. Such scenarios presented in the literature typically have BECCS at a $GtCO_2$ per year scale. We also assess the potentials and obstacles for BECCS implementation at the national level, applying Sweden as a case study. Given that BECCS deployment has scarcely started and, thus, is far from capturing 1 $GtCO_2$ per year, with lead times on the scale of multiple years, we conclude that there will be a large implementation gap unless BECCS development is immediately intensified, emissions are reduced at a much faster pace or removals realized through other CDR measures. In the national case study, we show that Sweden has favorable conditions for BECCS in that it has large point sources of biogenic emissions, and that BECCS has been identified as one potential "supplementary measure" for reaching the Swedish target of net-zero emissions in 2045. Yet, work on planning for BECCS implementation has started only recently and would need to be accelerated to close the implementation gap between the present advancement and the targets for BECCS proposed in a recent public inquiry on the roles of supplementary measures. An assessment of two ramp-up scenarios for BECCS demonstrates that it should in principle be possible to reach the currently envisaged deployment scales, but this will require prompt introduction of political and economic incentives. The main barriers are thus not due to technological immaturity, but are rather of a socio-economic, political and institutional nature.

Keywords: carbon capture and storage, bioenergy, paris climate targets, sweden, net-zero

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Northwestern University, Philippines

***Correspondence:**
Sabine Fuss
fuss@mcc-berlin.net

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INTRODUCTION

An analysis of the 1.5°C pathways assessed in the recent IPCC Special Report on 1.5°C Global Warming reveals that CO_2 capture and storage (CCS) can reach up to 460 $GtCO_2$ cumulatively by mid-century, noting that this includes also CCS from coal and gas plants and that some pathways will still derive more than 20 EJ per year from coal in 2050 (Rogelj et al., 2018). In addition, Bioenergy with CCS (BECCS) remains as the major technology for removing CO_2 in the vast majority of

scenarios associated with a high likelihood of achieving ambitious climate targets, such as those laid out in the Paris Agreement (Rogelj et al., 2018). BECCS is a carbon removal technology that is considered as promising for the near future, as the technologies on which it is based–bioenergy as well as capture, transport and Storage of CO_2–have all been demonstrated at scale. Other important CDR methods include Direct Air Carbon Capture and Storage (DACCS) and afforestation or reforestation. Application of BECCS serves two purposes in terms of mitigating emissions: 1) it can offset 'hard-to-abate' sector emissions (Davis et al., 2018; Royal Society and Royal Academy of Engineering, 2018; Tong et al., 2019); and 2) in the longer run, it can create net-negative emissions, which would be required to return from a likely overshoot of the target (Luderer et al., 2018; Minx et al., 2018).

It is of course indispensable that fossil fuel reserves stay in the ground or are only used in association with CCS (see e.g., Johnsson et al., 2019), and that the application of CDR is not used as an excuse to postpone other mitigation measures. Currently, far more fossil carbon is used (80% of the primary energy supply) than biogenic carbon (around 12%). Moreover, a substantial share of the biomass uses is from so-called 'traditional' biomass (International Energy Agency, 2017), which means that the actual share is associated with large uncertainties. Nevertheless, there are countries with large forests, some of which have well-developed forest management systems with high productivity and with a net growth of the carbon stock. In addition, there is significant potential for establishing new biomass production systems, although there are substantial variations in the estimates of their potential contributions (Creutzig et al., 2015).

Still, there has been little progress toward the implementation of CCS and even less so in the case of BECCS (Peters et al., 2017). This has been confirmed by Fridahl (2017) who, based on survey responses from 711 delegates at a UN climate change conference, has reported that BECCS is not prioritized compared to alternative mitigation technologies. Therefore, we conclude that there is a large *implementation gap* between the dramatic ramp-up of BECCS (or alternative CDR options) in most of the ambitious climate stabilization pathways that are mainly generated by Integrated Assessment Models (IAMs) (Clarke et al., 2014; Smith et al., 2016; Minx et al., 2018; Rogelj et al., 2018) and the current development of BECCS at both the global and regional scales. This gap is unlikely to be closed in the absence of strongly enhanced climate policies. Currently, the price signal for CO_2 is too weak for CCS (e.g., in the EU emissions trading system; EU ETS) and no climate policy presently exists that provides incentives strong enough for BECCS to be deployed at scale.

In this work, we focus on BECCS and compare its timeframes in key global scenarios with the timeframe of implementation at the national scale, applying Sweden as a case study. We use Sweden because: 1) in theory, it holds favorable conditions for BECCS, having a well-developed forest industry and net growth of carbon stock in the forests; 2) it has strong ambitions to become a forerunner in climate action, having established a national target of achieving net-zero emissions by 2045, after which emissions should be net-negative; and 3) a public inquiry (SOU, 2020) recently conducted in Sweden has proposed actions to accelerate CDR upscaling (in particular, BECCS) and has suggested explicit targets for BECCS in 2030 and 2045. Bellamy and Geden (2019) cite Stockholm Exergi, which is the provider of district heating for the capital of Sweden and which is currently using biochar (a byproduct of heat generation from biogenic waste) to remove CO_2 and is planning for BECCS (currently having a small test unit in operation) (Gustafsson, 2018) as an example of companies that are acting as early movers to comply with the Swedish net-zero greenhouse gas (GHG) target by 2045. Similarly, Honegger and Reiner (2018) have pointed out that it will be up to potentially progressive industrialized countries to take the first steps toward mobilizing CDR, including BECCS. Considering the above three points, and considering its national political rhetoric, Sweden appears to be well placed to take on such a role.

The present study addresses two important questions related to BECCS in the national context: *Under what conditions can BECCS be ramped up in Sweden and can that knowledge help us understand other regions and focus attention on the leverage points needed for BECCS scale-up?* In tackling these questions, we refer to the BECCS implementation gap as the difference between–on the one hand–the rates of BECCS deployment observed in the global 1.5°C pathways (see *Bioenergy Combined With Carbon Capture and Storage in the 1.5°C pathways*) and–on the other hand–the actual progress of implementation with respect to technology, policy and economics, governance and society (*The potential role of BECCS in Sweden*). Fridahl (2017) has stressed the need for studies of the sociopolitical preconditions for large-scale CDR deployment. The present paper also contributes to revealing the corresponding knowledge gaps, while also identifying areas for direct action. The latter is important, since there is an urgency related to developing concrete strategies for CDR implementation, and direct action is required in parallel with research if net-zero targets and, subsequently, net-negative levels of emissions are to be reached in time.

METHODOLOGY

To answer the research questions outlined above, we adopted a mixed-methods approach, starting with global climate stabilization pathways, primarily on the basis of the literature based on the use of IAMs. As already indicated, these models allow for assessments of the implications of and sensitivity to a wide range of parameters at global scales, and they complement national models that inform the implementation with greater granularity of the top-line policy requirements discovered by IAMs (Fuhrman et al., 2019). Thus, the resulting global pathways represent a natural point of departure for motivating our national case study, which represents a comprehensive exploration of the potential with higher granularity for policymaking. This may not only translate the acquired knowledge to countries with similar conditions, but may also serve to identify aspects that can be

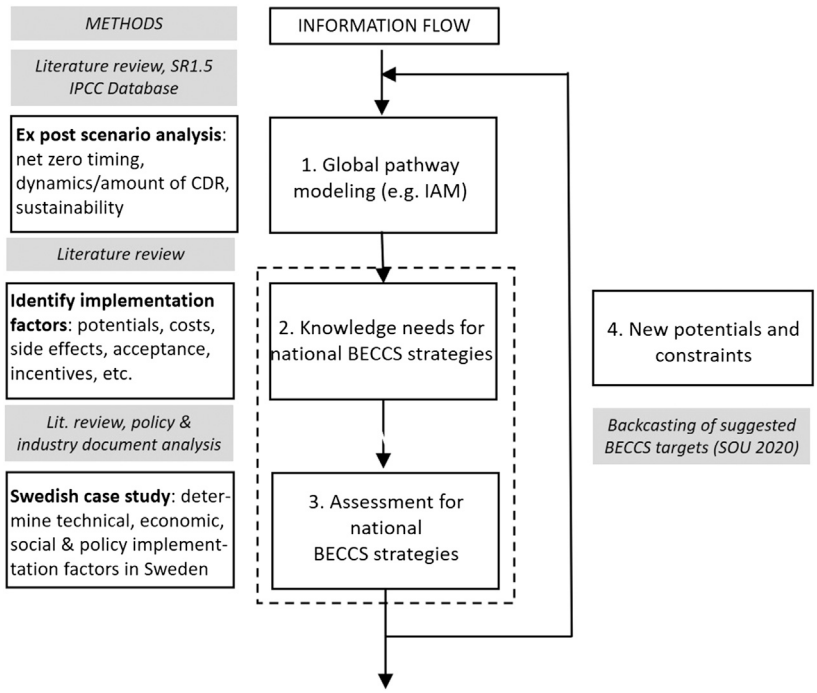

FIGURE 1 | Schematic of the procedure for assessing the role of BECCS through linking national strategies to global pathway modeling systems such as Integrated Assessment Modeling (IAM).

improved in global models, such as including hitherto unexplored BECCS potentials for industry. In this section, we outline the steps of our approach, following a schematic representation (**Figure 1**).

First, we assess the timeline for the required ramp-up of BECCS on a global scale, as obtained from the global 1.5°C pathways, taking these dynamics as guidance for national CDR strategies (Step 1 in **Figure 1**). Subsequently, this is complemented with a review of the literature on the lack of connection between global pathways and national strategies, and identifying knowledge needs for the latter (Step 2 in **Figure 1**). We then examine Sweden as a regional BECCS case study (Step 3 in **Figure 1**) by using qualitative analysis, underpinned with quantitative data when possible: 1) analyzing the technical conditions for BECCS rollout in Sweden; 2) assessing the potentials and costs of Swedish BECCS based on the peer-reviewed literature and information obtained from industry; 3) distilling insights into Swedish policy planning for BECCS from the recently issued SOU 2020:4 report titled *The road toward a climate positive future*, which emerged from a public inquiry; and 4) eliciting potential barriers related to social acceptance based on the peer-reviewed literature. These steps allow us to characterize more definitively the BECCS implementation gap for the Swedish regional case and to identify the initial entry points for actions to close this gap. In particular, we develop two hypothetical roadmaps for upscaling BECCS in Sweden, based on observations of existing industry plans, and use these roadmaps to assess the BECCS targets suggested in the SOU 2020:4 report. Thus, the targets serve as a starting point and we backcast the pathways to reach these targets, in the process of which we attain a better understanding of the underlying conditions that need to be in place for the roadmaps to be realized. These underlying conditions are thereafter highlighted in the conclusion.

Finally, as depicted in the flow diagram in **Figure 1**, this chain of analyses does not need to culminate in informing national strategy. Instead, newly identified potentials and constraints can be fed back into the modeling of global pathways (Step 4 in **Figure 1**), so as to provide more realistic assumptions for IAMs concerned with the prospects of BECCS. In order for a comprehensive feedback loop to be established, the procedure obviously has to be carried out for all countries and regions for which BECCS can be identified as a potentially important technology. The latter is clearly beyond the scope of the present study and is to be understood as indicative of future research on this topic.

BIOENERGY COMBINED WITH CARBON CAPTURE AND STORAGE IN THE 1.5°C PATHWAYS

While this study focuses on BECCS, it is important to note that for a complete analysis, fossil fuel CCS has to be considered also, given that many of the inhibiting factors that lead to the BECCS implementation gap are inextricably linked to the development of

fossil fuel CCS. There are also several emissions sources that use a mixture of fossil and biogenic feedstocks, such that if they are equipped with CCS they will to some extent be a BECCS application. In addition, as CCS and BECCS are typically based on the same technologies, their demonstration and scale-up should not be treated separately but in an integrated manner to accelerate the learning process toward large-scale implementation. The 1.5°C pathways that have been assessed in the IPCC Special Report on 1.5°C Global Warming feature quantities of CO_2 stored through CCS until 2100 that range from zero to 1900 $GtCO_2$ depending on the portfolio of mitigation measures (Rogelj et al., 2018). The 1.5°C pathways that exclude CCS completely–such as the one by Grubler et al. (2018)–foresee much higher potentials for demand-side mitigation measures than the previously described pathways and, in particular, much lower energy demand. All the 1.5 °C pathways obviously require a comprehensive phasing out of the use of fossil fuels, in particular coal. CCS could allow a smoother transition for countries that have large endowments of fossil fuel reserves, which represent an important component of their economies (Johnsson et al., 2019), while complying with strict emission reductions. Since CCS can also be applied to biogenic emission sources, it represents a versatile mitigation technology. It can, on the one hand, limit CO_2 emissions from fossil fuels used for electricity generation, liquids production and industrial applications, and on the other hand, potentially remove CO_2 from the atmosphere when combined with bioenergy (Kriegler et al., 2014).

Of the up to 460 $GtCO_2$ captured and stored up to 2050 in the above-mentioned IPCC Special Report on 1.5°C Global Warming (IPCC, 2018a), up to 190 $GtCO_2$ are derived from biogenic sources and that fraction will typically increase in the second half of the century (Rogelj et al., 2018). In particular, pathways that limit global warming to 1.5°C *with limited or no overshoot* feature BECCS deployment of up to 1, 8, and 16 $GtCO_2$ per year in 2030, 2050, and 2100, respectively (IPCC, 2018b). BECCS that results in the removal of 16 $GtCO_2$ per year would deliver ~225 EJ per year of primary energy (assuming BECCS is used in electricity generation) in 2100 (Smith et al., 2016), as compared to the current level of about 50 EJ of biomass energy per year. In addition to scaling up BECCS, this would obviously require a substantial scaling up of the biomass supply from agricultural and forestry residues, as well as from dedicated bioenergy crops grown on abandoned agricultural land and expansion into grasslands (Vaughan et al., 2018). While the estimates vary widely, most of the literature indicates that biomass energy could be scaled to something between 100 and 300 EJ per year by mid-century (Smith et al., 2014; Vaughan et al., 2018). This level would be exceeded in pathways that stabilize at 1.5°C in 2100 but that overshoot the target during the century.

The nature of the side-effects from BECCS crucially depends on the mode of implementation and the scale. Thus, the planting of monocultures for increased use of biomass, for example, could indeed result in carbon removal but might also be at odds with other societal and environmental goals, e.g., other Sustainable Development Goals (SDGs) related to food security and biodiversity conservation (Smith et al., 2019). There is a vast body of literature testifying to an increased demand for land from large-scale BECCS, putting food production, biodiversity, etc. at risk (see Fuss et al., 2018a and references therein). Resorting to marginal land or using residues as well as dedicated crops, as shown by Vaughan et al. (2018), could mitigate some of this risk. Yet, at carbon removal levels in the double-digit Gigatonne range, as given above, fewer and fewer opportunities for careful implementation remain, resulting in increasingly severe trade-offs for different land uses. This comes on top of the uncertainties associated with the availability of marginal and degraded land globally. Obviously, the associated ramping up of the biomass supply would be a tremendous challenge.

A systematic literature review of more than 1,000 studies (Robledo-Abad et al., 2017) regarding the side-effects of bioenergy reveals that there can be both trade-offs and co-benefits. However, negative effects are more often reported in the literature that focuses on the social and environmental dimensions, mostly in relation to land use changes that have impacts on ecosystems and food security. Positive effects of bioenergy are more often observed in techno-economic studies, emphasizing the technological opportunities, such as yield increases, and economic benefits (e.g., employment opportunities). Similarly, the majority of the non-IAM literature on BECCS is more concerned with the negative side-effects that a large-scale rollout would have for different dimensions of sustainability, with most of the research being concerned with the land footprint, highlighting the detrimental impacts on the safeguarding of terrestrial ecosystems and the provision of food security for a growing population (Fuss et al., 2018b; Smith et al., 2019). Other CDR options, such as Enhanced Weathering or increasing ocean alkalinity, do not feature a large land footprint, although they are associated with other uncertainties and, thus, not widely included in IAMs to date, making an integrated assessment difficult. In fact, since model intercomparison of wider CDR portfolios in IAMs has only recently started (e.g., Realmonte et al., 2019) and many IAM experts themselves are critical of the notion that IAMs can be expanded to many CDR methods beyond BECCS (Rickels et al., 2019), the discussion is still very much focused on the environmental sustainability of BECCS.[1] However, since IAMs have a rather crude representation of the supply chains associated with many BECCS technologies and lack regional detail, many of the low-hanging fruits in the area of BECCS are still not accounted for–in the same way that the lack of reconciliation between top-down and bottom-up approaches has been identified as leading to important tradeoffs being overlooked in the related context of bioenergy (Creutzig et al., 2012). IAMs thus may also overestimate realistic BECCS deployment rates due to a lack of realistic regional assumptions related to, for example, a sustainable and socially acceptable biomass supply. In general, the missing granularity of top-line policy requirements uncovered by IAMs (Fuhrman et al., 2019) reflects the difficulties

[1]Note, however, that recent work examining the impact of a larger roll-out of DACCS still finds an important role for BECCS in the mitigation portfolio (Fuhrman et al., 2020).

TABLE 1 | Key messages from the analysis of global BECCS pathways.

Key messages	*Selected key references*
BECCS is a key CDR element of global pathways aiming to reach the Paris Agreement targets: Up to 190 $GtCO_2$ from biogenic sources are stored in 1.5°C pathways until mid-century.	Rogelj et al. (2018)
BECCS has been under severe scrutiny on account of the implied land use competition.	Vaughan et al. (2018), de Coninck et al. (2018), Robledo-Abad et al. (2017), and Butnar et al. (2020)
The potentials of countries with existing biogenic emission point sources and possibilities for access to storage and experience with CCS are often not captured in global pathways and *ex post* sustainability assessments, but there is growing evidence on their existence and significant extent.	Johnsson et al. (2020), Johnsson and Kjärstad (2019), Klement et al. (2021), and Garðarsdóttir et al. (2018)
Global pathways, mostly derived from IAMs, can provide guidance for national policymaking, although they need to be accompanied by higher-granularity analyses for a multitude of factors, ranging from societal preferences to models for innovation.	Forster et al. (2020), Gambhir et al. (2019), Gough and Mander (2019), Laude (2020), Fuhrman et al. (2019), and Bellamy and Geden (2019)

associated with assessing geologic suitability and feasibility from the perspectives of other SDGs.

Another dimension of implementation that is not well-represented in global IAM modeling is the absence of good governance systems for the management of biomass systems across the globe. As Vaughan et al. (2018) have pointed out very clearly, only one-third of bioenergy crops are grown in regions associated with more-developed governance frameworks. This could impact negatively both the environmental and social sustainability aspects if even more biomass was to be needed in the future, as confirmed in IAM studies such as that carried out by Butnar et al. (2020). Global climate pathways might also create the impression that governance will have to be jurisdictional or even global, in particular when considering the removal of tens of Gigatonnes of CO_2. Yet, while there may be aspects associated with, for example, the sustainability of large-scale land use change that would need at least global coordination, there is increasing recognition that CDR will primarily emerge as a bottom-up strategy that is governed by companies and cities, which means that it cannot be comprehensively coordinated in a top-down fashion globally (Bellamy and Geden, 2019). This indicates opportunities for nested governance approaches, which have often been recommended in the context of Reduced Emissions from Deforestation and Degradation (REDD+) (Kashwan and Holahan, 2014).

Finally (heterogeneous) societal preferences are not yet captured in IAMs (Forster et al., 2020). Whether and to what extent different types of CDR technologies and practices will be acceptable to society are issues that do not yet feature in IAMs. Nonetheless, the scenario space has recently started to widen in this respect, both in terms of constraining contested technologies and land use change and through the explicit integration of the mitigation potentials of hitherto largely unexploited opportunities associated with processes such as innovation and behavioral changes (Grubler et al., 2018; Rogelj et al., 2018; van Vuuren et al., 2018).

Given that BECCS deployment has scarcely started and, thus, is far from being capable of capturing 1 $GtCO_2$ per year and that lead times are on the scale of multiple years (see also *The potential role of Bioenergy Combined With Carbon Capture and Storage in Sweden*), there will be a large implementation gap if emissions cannot be reduced at a much faster pace and removals cannot be realized through other CDR measures, such as afforestation. This implementation gap is further exacerbated by the paucity of knowledge regarding the efficient ramping up of BECCS (Nemet et al., 2018). As this will depend on local conditions, there is a great need to assess the national context for the upscaling of BECCS. Otherwise, there is a risk that BECCS will largely remain a hypothetical technology (e.g., in IAM models), resulting in an underestimation of the actual implementation gap and, consequently, too much faith being placed in BECCS as a straightforward solution for achieving national net-zero goals (Laude, 2020). To date few countries and states, e.g., Sweden, the United Kingdom, and California, are actively looking into the definitive CDR portfolios to be deployed in order to fulfill their national (or federal) climate neutrality goals, including the policy framework (Committee on Climate Change, 2019; Baker et al., 2020; SOU, 2020). **Table 1** summarizes the key messages from the analysis of the global pathways for BECCS.

We take an initial step toward addressing this knowledge gap by focusing on the case of Sweden, which has many existing biogenic emission sources, access to a sustainable biomass supply chain, technological experience with carbon capture in research and demonstration, and ties to the Northern Lights Project on storage infrastructure. Thus, there should exist in principle good conditions for a relatively rapid ramping up of BECCS, which would significantly contribute to the national net-zero (or, in this case, even net-negative) emissions goals. It is important to emphasize the need for such national case studies to complement IAM policy pathways (for the reasons outlined above). The analysis conducted herein should, therefore, not be understood as a substitute for IAMs, in line with what has been concluded by others (Gambhir et al., 2019).

THE POTENTIAL ROLE OF BIOENERGY COMBINED WITH CARBON CAPTURE AND STORAGE IN SWEDEN

Entry Points for a National Bioenergy Combined With Carbon Capture and Storage Strategy: Technical Potentials

Sweden is a highly industrialized country with several basic-material industries, such as iron and steel, cement, and pulp and

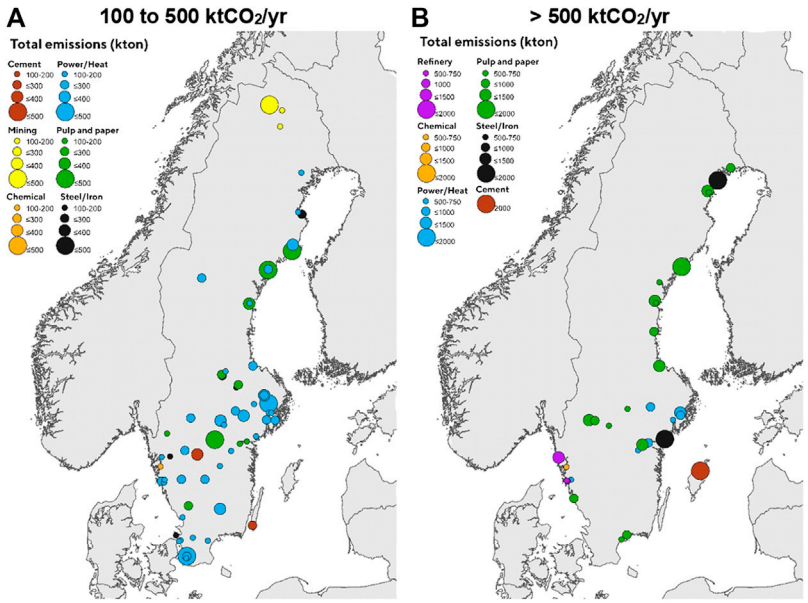

FIGURE 2 | Swedish emissions sources from different types of plants with: **(A)** emissions in the range of 100–500 $ktCO_2$/year; and **(B)** emissions >500 $ktCO_2$/year. Reproduced from (Johnsson and Kjärstad, 2019).

paper (P&P), all of which emit substantial amounts of CO_2. At the same time, the electricity generation system is to a large extent CO_2-free, since hydro power and nuclear power each provide around 40% of the electricity generation, with the remaining 20% being mainly from wind power and the power generated in combined heat and power (CHP) plants.

Sweden has a well-developed forest industry with high-level production of various biomass-based products, such as saw timber, P&P, and different wood products. The Swedish forest industry is established around large forestry resources and a well-developed forest management system with a growing carbon stock in the forests (Swedish Environmental Protection Agency, 2017). In addition, there is the potential to enhance forest productivity, so as to increase the output levels of forest products while enhancing carbon sequestration in the forests (Cintas et al., 2017). The waste from the forest industry (branches and stumps from the forests and wood waste from the timber industry) is used in the energy system, typically in heat only and CHP plants in district heating systems. Thus, current biomass use follows a cascading principle from long-lived products to paper products to the biomass waste fractions used for energy purposes. Since the 1990s, there has been an increase in the use of biomass in the transportation sector, with biofuels mainly produced from biogenic waste from the P&P industry in the form of tall oil, together with imported biofuels. The current share of biomass in road transportation is around 20%. However, the major share of biomass is used in industry, mainly for saw timber (46%) and pulpwood (42%), with the remaining share (including residues from industrial use) being used in the energy sector. Thus, there are large biogenic point sources from these biomass conversion processes, mainly P&P plants and CHP plants (Garðarsdóttir et al., 2018). This can be concluded from **Figure 2**, which shows a map of the Swedish large point sources of CO_2 emissions (including both fossil and biogenic). **Figure 2a** shows the sources with emissions in the range of 100–500 $ktCO_2$ per year and **Figure 2B** shows those sources with emissions that exceed 500 kt per year. As for the BECCS potential, there are around 70 facilities with biogenic CO_2 emissions of >100 kt per year, which together exceed 30 $MtCO_2$ per year.

If applying CO_2 capture to these emission sources, storage can most likely be "purchased" from Norway, as that country has well-documented storage (Anthonsen et al., 2013; Lyng Anthonsen et al., 2016) and advanced plans for the establishment of a transboundary storage infrastructure, although this will result in a dependency on foreign infrastructure operators. Work on establishing the Norwegian storage infrastructure has already started (the Northern Lights Project for storage in the North Sea). This project should be favorable for reducing lead times once capture projects are initiated in Sweden. In particular, Northern Lights, which is being developed by Equinor (formerly Statoil), includes intermediate storage facilities for receiving CO_2 transport by ships (Equinor, 2019; Furre et al., 2019). The realization of this infrastructure is linked to the execution of the first two Norwegian large-scale, on-shore CCS projects. These projects will each capture around 400 $ktCO_2$ per year: from the Norcem cement plant in Brevik (south of Norway); and from the waste-fired CHP plant in Klemetsrud (south of Oslo). The Norwegian Oil and Gas Ministry has recently proposed (Det Kongelege Olje- og Energidepartementet, 2020) that the cement plant should receive State funding (with the Norwegian Government covering the major part of the cost over 10 years), and that the CHP plant should receive funding provided that 50% of the total can be raised from sources

other than the State (a decision on this was taken in December 2020, forming the so-called "Langskip"-project).

Figure 2 clearly shows that a substantial proportion of the largest emission sources in Sweden is located along the coastline which, in a future CCS/BECCS system, will facilitate transport of the captured CO_2 by ship to geologic storage sites located beneath the North Sea. It is not clear what the lower limit in terms of the size of flue gas flow will be for applying CO_2 capture. This will depend on the concentration of CO_2 in the flue gases, climate policy, the value of the product, and customers' willingness to pay for climate-neutral or climate-positive products, which in turn will depend on which value chain is considered. It seems likely that the initial projects (beyond demonstration projects) will target large emissions sources, e.g., those exceeding 500 $ktCO_2$ per year (**Figure 2B**). Once there is sufficient experience of using the CCS technology and a transport and storage infrastructure has been established that can be shared with additional capture plants, capture could be applied to smaller sources of emissions, perhaps those with emissions of 100-500 $ktCO_2$ per year (**Figure 2A**).

The combination of the many existing biogenic emission sources and the access to well-established biomass markets, supply chains, and forest management system should provide favorable conditions for BECCS. Thus, Sweden can be expected to be an early driving force for implementing BECCS, in particular if it teams up with Norway for storage in connection with the Northern Lights Project (or possibly with other upcoming Dutch or UK storage projects in the North Sea). The challenge will be to establish policies that create incentives for mitigating biogenic emissions. Such policies are lacking at present but have been proposed, as discussed in *Climate targets*.

The Economic Potential

Johnsson et al. (2020) have generated a marginal abatement cost curve for CCS (post-combustion using amine scrubbing) applied to the largest industrial emissions sources in Sweden (excluding CHP plants in the energy sector), with emissions exceeding 500 $ktCO_2$ per year (**Figure 2B**). These include 28 units, representing cement (1 plant), chemicals (1 plant), iron and steel (3 plants, including a CHP unit), refineries (3 plants), and P&P plants (20 plants). These plants constitute a mix of fossil fuel and biogenic emissions (several of them having multiple stacks). The total emissions captured from the 28 industrial units amount to 23 $MtCO_2$ per year, which corresponds to more than half of Sweden's total (fossil fuel) CO_2 emissions from all sectors (around 43 $MtCO_2$ per year).[2] This level of capture is achieved at an average cost of 80–135 €/tCO_2 if one includes the costs for transport and storage (Johnsson et al., 2020). If the same level of emissions was to be captured solely from fossil fuel emissions, capture would have to be included also for smaller sources of emissions, thereby driving up the cost significantly. This shows that BECCS should not be treated in isolation. Instead, it should be integrated with CCS in order to follow a cost-efficient ramping up of CO_2 capture. In addition, there are opportunities to capture CO_2 from CHP plants that are mainly burning biomass (branches and tops from forestry), including waste-fired units that typically burn a mixture of renewable and fossil (plastic waste) fuels. All in all, it can be concluded that Sweden has strong potential for BECCS with the already existing point sources of biogenic emissions. Thus, capturing CO_2 from industrial emissions sources represents a powerful approach in that it can remove a substantial portion of CO_2 emissions through implementing CCS at a limited number of plants. It should be noted that maintaining the outputs from plants when adding BECCS will require increased sources of biomass supply (to compensate for the loss of efficiency of the process), although the degree to which this supplementation is necessary depends on the type of process, including the availability of waste heat to power part of the capture process.

When it comes to the potential for storage, there is, on the one hand, a large storage potential in Norway and, as mentioned in the previous section, work has already been initiated to establish a storage infrastructure. On the other hand, Sweden has limited storage capacity within its own territory and there is little geologic information on the storage conditions. As a consequence, determining the actual storage capacity would require substantial geologic surveying (see Mortensen et al. (2016) and Mortensen et al. (2017) for overviews of the Swedish storage potential).

Climate Targets

In 2017, Sweden adopted a climate policy framework that consists of a climate act, climate targets, and a climate policy council. Sweden's long-term target is to have net-zero GHG emissions by 2045 at the latest, after which the emissions should be at net-negative levels (Swedish Environmental Protection Agency, 2017). Net-zero emissions by 2045 are specified as at least an 85% reduction in domestic emissions, as compared to the corresponding levels in 1990. Thus, up to 15% of the reductions can be met by so-called 'supplementary measures', which can involve carbon removal through BECCS or other technical measures (e.g., DACCS[3]), increased carbon uptake by the terrestrial biosphere (e.g., afforestation), and the implementation of offsetting measures abroad. That is, these removals are designed to compensate for the residual emissions that are expected to occur in 'hard-to-abate' sectors (cf. Davis et al., 2018; Luderer et al., 2018 on compensation of residual emissions at the global level), such as agriculture and the use of fossil fuels in transport, most notably aviation. The requirement for measures to be taken in other countries (offsets, so to say) is that they must be above and beyond what would otherwise have been done in those countries. Concerning the 'supplementary measures', it is reasonable to

[2]Sweden's total GHG emissions were 53 $MtCO_2$ in 2018.

[3]In the Swedish Climate Political framework of 2017 only BECCS is mentioned as possible CDR avenue. In the Governmental Inquiry (SOU, 2020) it is proposed that negative emissions can also be obtained by means of other technical measures which are verifiable.

assume that BECCS, owing to its favorable conditions, will be a suitable candidate technology.

The recently published inquiry conducted for the Government of Sweden (SOU 2020:4) regarding supplementary measures has proposed that such measures should be created to account for the equivalent of at least 3.7 $MtCO_2$ of CDR by 2030. Up to 2045, the corresponding level is set at 10.7 $MtCO_2$. The inquiry (SOU2020:4) has concluded that it will be much more costly to reach the target of net-zero emissions in the absence of such supplementary measures, since that would require a comprehensive transformation of the agricultural sector (e.g., to mitigate non-CO_2 emissions such as methane and nitrous oxide). The SOU2020:4 inquiry report proposes that BECCS is critical for meeting the target of net-negative emissions after 2045. The report also indicates that the climate policy action plans, which the Government of Sweden submits to the Parliament every 4 years, should include how the work on the supplementary measures is progressing. The system for collecting data and reporting of the removals should be carried out by the Swedish Environmental Protection Agency, which is already monitoring progress toward reaching the national climate goals.

Incentives

From the work conducted by Johnsson et al. (2020), the average cost for capture, transport and storage can, for the sake of simplicity, be averaged at 100 €/tCO_2–a cost level that is almost identical to the Swedish CO_2 tax (somewhat exceeding 100 €/tCO_2). However, only selected parts of the economy, such as the transportation sector and the heating sector, are in reality exposed to this tax. Incentives for mitigating the above-mentioned large point sources of fossil fuel emissions (**Figure 2**), for which CO_2 capture is an option, are manifested through the EU ETS. However, the present allowance price of around 30 €/tCO_2 is considerably lower than the cost of CCS, and previous research has shown that political uncertainty can have a detrimental impact on future price developments (Koch et al., 2016; Fuss et al., 2018a). For the biogenic emissions, there are as of yet no economic mitigation incentives. Thus, a ramp-up of BECCS will obviously require governmental intervention in order to establish incentives and, thereby, reduce the risks for the investor. As for CCS, there is a need to reform the EU ETS to increase allowance prices or to provide governmental intervention until allowance prices have reached a sufficiently high level. Examples of accompanying measures that foster CCS from other parts of the world include Low Carbon Fuel Standard (LCFS) policies and the 45Q tax credit for US industrial manufacturers that capture carbon from their operations. The latter would earn US$50 per metric tonne of CO_2 stored permanently or $35 per metric tonne if the CO_2 is put to use, which could mean that the balance does not remain negative (Hepburn et al., 2019). Finally, it is also important to devise incentive schemes that gain strong acceptance within society (see also the discussion of Bellamy et al. (2019) in *Incentives*), as well as from industry.

When it comes to Sweden creating incentives for CDR, the report proposes a reverse-auctioning process (one buyer–the Government–and many sellers–those who can offer carbon removal). It is proposed in the SOU2020:4 report that the reverse auctions would result in differentiated guarantee prices for actors who win the auctions for storing CO_2 from biogenic sources. The auctioning system aims to serve as an initial support and it would by 2030 be limited to 2 $MtCO_2$ per year, which would correspond to 3–5 BECCS plants. The system will thereafter be evaluated to decide what continued governance is required for BECCS. Furthermore, it is stated in SOU2020:4 that "*the compensation paid out should be the difference between the agreed guarantee price and the value of any EU funding and national funding to promote bio-CCS that an actor receives. To have funds paid out, it is required that the project owner has applied for relevant support from the EU*". Thus, if no EU funding is secured, the system gives a contracted guarantee price that will be paid in full. If EU funding is secured, the difference between the EU funding and the guaranteed price will be paid by the Swedish State, i.e., corresponding to a contract-for-difference scheme. At present, it is not known when there will be any incentives to mitigate biogenic emissions within the EU ETS. Integration of CDR into the EU ETS would require an amendment to the EU ETS Directive (installations only using biomass are not covered by the ETS Directive); see Rickels et al. (2020) for a discussion of CDR and EU emissions trading.

While the details of the reverse-auctioning system are not yet established (and other incentive schemes are being evaluated), it seems likely that it will only apply as long as there is a positive difference between the guaranteed price from the auctioning and any EU funding (such as emission credits or support from the EU innovation fund or other investment or operational support schemes). If such funding is greater than the contracted guarantee price, the system can be designed so that the difference will not have to be paid to the State (corresponding to a price floor but not a price ceiling) or so that it has to be paid back to the State (in that case, corresponding to both a price floor and a price ceiling). There are obviously also other design issues that must still be outlined, e.g., when payments should be issued (SOU2020:4 suggests that partial payments be made in advance, to act as a form of investment aid and with a binding period of 10–20 years, thereby enabling long-term planning for the parties involved).

Assuming that the auctioning scheme proposed in SOU2020:4 will be implemented, there will be a level of predictability associated with the funding of BECCS, thereby compensating for the uncertainty emanating from the EU level, where there are still no incentives for CDR. It is also not clear–and probably not an obvious task–as to how to coordinate the national auctioning system with any EU measure for supporting CDR. Perhaps for that reason, it is (in SOU2020:4) proposed to develop a common, long-term instrument to promote BECCS either in a technology-neutral manner or by altering the EU ETS so that BECCS gives rise to emission credits that may be used within the EU ETS. However, this would require that measures are taken to adjust the number of emission allowances in the system, to avoid undermining incentives to reduce fossil-fuel emissions. In the SOU2020:4 report, it is concluded that the development of a common instrument to promote BECCS may be the easiest way forward, since it will not require renegotiation of the EU's main legal provisions.

Although SOU2020:4 proposes that the reverse-auctioning system be limited to a maximum of 2 $MtCO_2$ captured and stored annually by 2030, it expects a certain shortfall of this level and assumes instead that 1.8 $MtCO_2$ can be reached. Assuming an average cost of 100 €/tCO_2[4] and no other EU policy measures are in place to create incentives for BECCS or other CDR methods with lower cost significantly contributing to carbon removal, this would mean that the Government of Sweden would have to pay out up to 180 million € per year[5]. This can be compared to the annual intake from the Swedish CO_2 tax, which amounts to 2.3 billion €. If capture was applied to all biogenic emissions from the above-mentioned industrial plants, around 10 Mt/year (cf. Johnsson et al., 2020), the associated governmental financing would amount to around 1 billion €/year. The latter seems unlikely, although it is a reasonable assumption that 10 Mt/year will only be reached in the longer term when other financing instruments have been found and costs have been decreased further. These figures can also be placed in the context of the substantial economic recovery packages being applied for restarting the economy after the COVID-19 pandemic, with one of the Swedish recovery packages being worth up to 10 billion €. Thus, it is not so obvious what constitutes a high or a low cost for climate mitigation, as this depends both on the value of the avoided externalities if climate targets can be met and the influence on the economy in a wider sense (such as job creation or job losses resulting from mitigation measures). In general, there are indications that the levels of governmental spending on recovery packages (globally) are much higher than the spending required to change course so to be in line with the Paris Agreement (Andrijevic et al., 2020).

Assuming that the auctioning (possibly together with other support measures) will cover the cost of BECCS (around 100€/tCO_2, as mentioned above), this may result in a higher value of CDR compared to the cost of causing fossil fuel emissions, at least up to 2030, since the allowance price within the EU ETS is at present around 30€/tCO_2. There is an obvious difference between fossil and biogenic carbon emissions in that removing carbon from the atmosphere is a benefit for society, although it confers no extra benefit on the BECCS operator, whereas fossil emissions generate economic benefits for the operator but result in external costs. One has to be conscious of the risk of making it more profitable to establish CDR by means of bioenergy with capture than to avoid fossil fuel emissions in the first place (i.e., the value of CDR would exceed the penalty of emitting fossil emissions). In this case, there would, for example, be incentives to install inefficient BECCS plants because more CO_2 could be captured (cf. Fajardy et al., 2018), which would result in enhancement of undesirable side-effects from increasing the biomass demand for BECCS. This is important to avoid, since CCS and BECCS are still representing 'linear' systems, and are not necessarily promoting a circular economy. It will obviously always be beneficial for the climate that measures are taken to store carbon that would otherwise have been emitted to the atmosphere. However, with a scarcity of climate-neutral carbon atoms, combustion processes with heat losses are not favorable and, thus, losses should at least be minimized.

The SOU2020:4 inquiry also proposes that the reverse auction could be opened to other CDR technologies, although it is concluded that these are currently technically immature and, therefore, of lesser relevance. Nevertheless, there are already initiatives[6] that attempt to stimulate interest in DACCS concepts, primarily for hard-to-abate sectors. Although DACCS is considered to be almost an order of magnitude more expensive than conventional CCS (and BECCS), see Gambhir and Tavoni (2019) and references therein, it has the advantage of being more flexible with respect to location and can be installed close to storage units (although to take advantage of storage in the vicinity of the DACCS plants, the storage needs to be onshore or by a coastline near the offshore storage unit). A recent review of DACCS technologies (Fasihi et al., 2019) points to that capture costs with DACCS can come down to 100 €/tCO_2 or less, which seems surprisingly low considering that capture is performed at a concentration of little more than 400 ppm CO_2, as opposed to CCS and BECCS which capture CO_2 at percent levels (typically 5–20% depending on the type of emission source). In some locations, such as in Iceland, geothermal (free) heat is available for powering DACCS (of a low-temperature DACCS type, such as the technology proposed by Climeworks; Beuttler et al., 2019), which may reduce costs and, thereby, help to reach the above-mentioned cost. It may very well be that sectors with hard-to-abate emissions may find it worthwhile to invest in DACCS as an independent mitigation option to compensate for their costly residual emissions. In summary, DACCS can be a realistic complement to BECCS, although this would require the technology to be demonstrated at scale and to be shown to bring down the cost.

An alternative or complementary way to finance BECCS is based on the fact that an assumed CCS cost of 100 €/tCO_2 will only marginally influence the prices of the end-products. Rootzén and Johnsson (2016) and Rootzén and Johnsson (2017) have estimated the increases in the price of a car and of a building made of CO_2-neutral steel and cement and steel, respectively. These materials are rendered CO_2-neutral through CCS (as part of a portfolio of measures within which CCS is a substantial component) at a total cost of around 100 €/tCO_2. It is shown that this would result in price increases for the car and the building of less than 0.5% (Rootzén and Johnsson, 2016; Rootzén and Johnsson, 2017). This result may open an entry point for voluntarily initiated 'climate clubs', whereby companies along key value chains gather to fund CCS (and other abatement options) through some risk-sharing scheme that enables them to provide climate-neutral products. Considering the heated debate on climate change, it is likely that such climate-neutral products

[4]Based on the 80–135 €/ton CO_2 cost range given by Johnsson et al. (2020).

[5]The figure will depend strongly on parameters such as the relation between CAPEX and OPEX, depreciation rate and should only be seen as an approximative upper value.

[6]The Nordic DAC Group is an initiative that promotes Direct Air Capture in Sweden and the Nordic countries: www.nordicdacgroup.com/.

will have a role to play, particularly since they only need to be marginally more expensive. A similar approach can be taken for BECCS. The consumer price increase to compensate for hard-to-abate sector emissions or to provide climate-positive end-products, i.e., products for which the associated emissions are offset (or more than offset) by other mitigation actions, may only be small. Klement et al. (2021) have analyzed the value chain of the P&P industry and shown that the cost for BECCS in the production of a number of low-value products, such as oat milk in paper packaging, card boxes and books, would only marginally affect the selling price if they were made of climate-positive paper. It is worth noting that within the food industry, there are already products marketed as climate-positive (e.g., a Swedish hamburger chain and dairy products). Since the climate benefits of many offset programs–often in the form of tree-planting in developing countries - have been criticized, BECCS (and DACCS) may have future roles here, since the climate benefit accrued from the actual storage of CO_2 would be hard to dispute in this sense (assuming that leakage can be ruled out).

Societal Acceptance

Concerning the levels of acceptability by the different groups in Sweden (the public, politicians, researchers, industry, etc.), domestic, sustainable biomass supply chains might imply lower barriers to public acceptance than are present in countries with concerns related to inducing indirect land use change, even though empirical evidence to support this hypothesis is still lacking. For the CCS part of the BECCS supply chain, there are also tentative indications that the societies in the Scandinavian countries are more open to deployment than other European countries (Haug and Stigson, 2016). At the same time, it has to be stressed that BECCS is not the preferred mitigation option and that renewables like solar and wind, for example, enjoy stronger public support (Fridahl, 2017). Some parts of the BECCS chain are also subject to conflicting views, especially the expansion of forest biomass production for bioenergy, even though this could change when it is combined with CCS (Fridahl and Lehtveer, 2018). One such view is that this type of strategy could substantially reduce forest carbon stocks due to an increase in clear-cut areas, which emit more CO_2 in the decade after harvesting, thereby neutralizing the emissions savings gained from substituting biomass for fossil fuels, with further negative side-effects such as impacts on biodiversity and higher vulnerability to climate change, as the number of tree species is decreased. As a consequence, proponents of this view demand that priority be given to storing carbon in existing forests. Another view opposes this demand, pointing out that the capacity for carbon sequestration in forests declines as they age, and that the carbon could be re-emitted in the case of wildfires, pests and other disturbances, which are likely to occur more frequently as results of ongoing climate change. An additional argument is that it is unlikely that society can quickly transition from using hydrocarbons in different conversion processes, including combustion, which underlines the importance of using renewable carbon, including biomass.

Another argument against the increased use of bioenergy is that it emits CO_2. While this is factually true, as long as there is net growth of carbon stocks and a need for carbon-based fuels and feedstocks (i.e., which cannot easily be replaced by renewable electricity), this argument is questionable (for a discussion, see Berndes et al., 2018). It is reasonable to assume that this argument will be further weakened for cases in which biomass is combined with CCS. An attempt to understand and reconcile these views of the role of forests in climate is elaborated by Berndes et al. (2018).

A recent study of public perception of BECCS carried out in the United Kingdom has also shown that the choice of policy instrument for incentivizing BECCS has an impact on the level of acceptance, in that payments for removal appear to be preferred over price guarantees for producers who are selling energy derived from BECCS (Bellamy et al., 2019). This fits with other studies that identify the framing as a critical factor in how society responds to BECCS technologies (Gough and Mander, 2019).

For a more comprehensive assessment of BECCS acceptance in Sweden, studies that directly target the Swedish public and other actors need to be conducted. There is a paucity of empirical evidence in this area, especially covering the full BECCS chain. Polling public attitudes to different mitigation technologies is difficult in terms of what the results from such polls will mean in an actual siting situation. However, since the application of BECCS at existing plants will not–in contrast to, for example, wind power–require new industrial sites to be developed, one may expect less public resistance than there would be to technologies requiring new siting. In particular, this will be true if applying BECCS to coastal emission sources in combination with ship transport, for which there will be no need to locate new pipelines. Acceptance will be inextricably linked also to how carbon removal will be governed.

Governance and Regulatory "Readiness"

As mentioned above, it still remains unclear as to how carbon removal originating from bioenergy generation with CCS will be accounted for, both at the national and EU levels. Monitoring, reporting and verification (MRV) would be transnational for some parts of the chain (e.g., as the storage will likely take place in Norway), giving rise to liability issues, as well as potentially raising geopolitical concerns due to the increased dependence on the foreign availability of storage space. Under scenarios of increased BECCS targets, good governance would also need to acknowledge the increased competition for biomass, which is also used for non-mitigation purposes. This connects to the need for a holistic governance that takes into account not only climate targets, but also a broader set of SDGs. Fuhrman and colleagues (Fuhrman et al., 2019) have identified overlaps with other SDGs in the context of CDR, which are not systematically assessed in the current IAM literature (*Bioenergy Combined With Carbon Capture and Storage in the 1.5°C pathways*).

As for the regulatory framework, there do not appear to be any major barriers to the storage of captured Swedish CO_2 emissions in Norway, although a bilateral agreement must be set up within a

TABLE 2 | Conclusions from case study–opportunities and uncertainties, risks and barriers for BECCS deployment in Sweden.

Favorable conditions	Selected key references	Uncertainties, risks, and barriers	Selected key references
Well-developed forest industry with net growth of the carbon stock	Swedish Environmental Protection Agency (2017) and Cintas et al. (2017)	Indications of sectoral contentions (forest biomass for bioenergy vs. maximizing the carbon stock of standing forest)	Berndes et al. (2018)
Large technical and economic BECCS potentials from many large, existing biogenic emission sources from the P&P industry and CHP plants	Garðarsdóttir et al. (2018), Johnsson and Kjärstad (2019), SOU (2020), and Johnsson et al. (2020)	Long lead times	This work (*Two Schematic Roadmaps of Swedish BECCS Ramp-Up*)
CCS chain (capture, transport and storage) is technologically mature, storage can be outsourced to Norway	Anthonsen et al. (2013), Equinor (2019), Furre et al. (2019), Johnsson et al. (2020), and Det Kongelege Olje- og Energidepartementet (2020)	Geopolitical dependence on Norway for storage, albeit with fragmented evidence with respect to the entire CCS chain. Price for Norwegian storage not known (in the public arena)	
Ambitious national net-zero GHG goal for 2045 (and net-negative emissions thereafter)	SOU (2020) and Swedish Environmental Protection Agency, 2017	Uncertainties associated with governance and policy (missing economic incentives and potentially incoherent policy when pricing fossil fuel emissions vs. removals)	Fajardy et al. (2018), Rickels et al. (2020), SOU (2020), Torvanger (2019), and Fridahl (2018), This work (*Two Schematic Roadmaps of Swedish BECCS Ramp-Up*)
Auctioning system for incentivizing BECCS has been proposed	SOU (2020)		
Societal acceptance and legal constraints concerning both bioenergy and CCS appear to be less prominent barriers than in other countries, although currently there is weak evidence	Fridahl (2018), Haug and Stigson (2016), Haikola et al. (2019), and Fridahl and Lehtveer (2018)	Increased biomass use questioned by some groups (NGOs, some researchers, and the public)	Berndes et al. (2018)
No barriers left in regulatory framework to store captured Swedish CO_2 emissions in Norway	International Maritime Organization (2019)	Unclear how carbon removal originating from bioenergy generation with CCS will be accounted for	Rickels et al. (2020)

provisional amendment (from 2009) to the London Protocol. A resolution that allows provisional application of the 2009 amendment has recently been set up jointly by Norway and the Netherlands (International Maritime Organization, 2019) and accepted, removing the barrier to cross-border export of CO_2 for offshore storage. This allows the six countries that have accepted the amendment to use the 2009 amendment provisionally. This should hold for all countries, including Sweden, provided a Declaration is made.

Table 2 summarizes the assessment of opportunities and barriers for BECCS deployment in Sweden, along with the underlying evidence for the assessment.

Two Schematic Roadmaps of Swedish BECCS Ramp-Up.

It is challenging to estimate a realistic timeline for the deployment of CCS and BECCS in Sweden and compare it to the ambition outlined in SOU2020:4. Therefore, we have resorted to designing two scenarios, which depend mainly on assumptions concerning the timeline of adding capture to plants, which are either existing or in the process of being built, while both assume sufficient incentives and no barriers to connecting to Norwegian geologic storage units. As mentioned previously, it can be argued that BECCS is based on proven technologies–if referring to post-combustion capture with amine-based capture, which is commercially available (Bui et al., 2018; Los Alamos National Laboratory, 2019). Post-combustion capture has been applied in the chemical industry for a long time, albeit for purposes other than CO_2 storage. With respect to the use of CCS, in 2019 there were 19 large-scale (>400 $ktCO_2$ yearly capture[7]) plants globally, with a further four plants under construction (The Global CCS Institute, 2019). Transport and storage have been proven at large scale and, for example, large-scale storage (around 1 $MtCO_2$ per year) has been carried out by the Norwegian natural gas industry in the North Sea since 1996. Thus, based on practical experience gained from the above as well as the authors' discussions with industry it can be argued that CCS is at a high technology readiness level (TRL), i.e., 8 or 9. Yet, applying CCS to new processes, such as those in the P&P industry, can be expected to be associated with long lead times, including the need for large-scale demonstration prior to commercial projects. In general, few studies in the literature have addressed the TRLs of CO_2 capture, including post-combustion capture, and the works that are available were completed before most of the above-mentioned large-scale projects were put in operation and, thus, generally point to lower TRLs (see Rubin et al., 2012 and references therein).

Assuming that the two Norwegian projects discussed in *The economic potential* will be approved during 2020, it will take at least three years until they are fully operational (and possibly only the cement plant will be completed within this time frame, if the

[7]Large scale: At least 400 $ktCO_2$ annually for industrial capture and at least 800 $ktCO_2$ for a coal power plant capture.

CHP plant fails to raise the required co-funding). In fact, the cement plant targets 2024 as the start-up year. When it comes to the cement industry, it seems reasonable to assume that the Norwegian capture project will need to be evaluated before capture will be installed at the Swedish cement plant. The main reason for this is that the Norwegian and Swedish cement plants have the same owner (Heidelberg Cement). As for CHP, there is also a small pilot project at Stockholm Exergi–the main utility for delivering heat within Stockholm–and this company has a target of having full-scale capture from their Stockholm Värtan plant by 2024 at the earliest (Levihn, 2020), although we assume that this is conditional on governmental support (such as that mentioned above). Thus, an optimistic scenario is that there will be capture at this plant by 2024 and at the Swedish cement plant some years later (assuming that the experiences from the Norwegian cement plant are in line with expectations). The Preem refinery on the West coast of Sweden has started to work with CCS, with the aim to apply CCS to their hydrogen production, which is part of the refinery process. Their level of hydrogen production will increase with their ambition to use more biogenic feedstock in the refinery. So far, they are–similar to Stockholm Exergi–operating a small pilot plant. Thus, the aspiration to have 3–5 full-scale BECCS plants (1.8 Mt per year) in operation by 2030, as is proposed in SOU2020:4, seems highly optimistic, albeit not impossible. It will require that at least two of these plants will be built in parallel and that there will be a more or less immediate "kick-start" of a coordinated BECCS program. However, considering the above-mentioned difference between the value of negative emissions required for a kick-start of BECCS and the lower cost of emitting fossil fuel CO_2, an additional support scheme will most likely be required–probably for CCS and BECCS concomitantly (in addition to other measures to achieve rapid and deep reductions of large point source emissions).

There are, according to 2016 data from the Swedish Environmental Protection Agency, 36 energy plants and 27 P&P plants with biogenic emissions that individually exceed 100 kt/year.[8] It should be mentioned that several of the CHP plants (the waste plants) burn a mix of biogenic and fossil fuels, increasing the total flue gas flow. The major share of the emissions from the P&P plants is biogenic, and these have generally large biogenic emissions, with 20 plants having emissions exceeding 500 kt/year (as mentioned above and analyzed by Johnsson et al., 2020). Other emissions sources, which in the future may contribute to negative emissions, are refineries and cement plants (three refineries and two cement plants), which are currently increasing their shares of biogenic feedstocks. Thus, their net emissions may become negative when applying CCS, depending on both the capture rate and biogenic feedstock share. In any case, there are sufficient numbers of biogenic emissions sources for BECCS to play a significant role, as also described in *The economic potential*.

The two roadmap scenarios focus on P&P plants and energy (CHP and heat-only) plants, since these constitute the major share of the current Swedish biogenic emissions sources. Both roadmaps assume that incentives for capturing biogenic emissions are in place, e.g., resulting from the proposed auctioning system proposed in SOU2020:4. In addition, as mentioned above, there are plans to apply capture to cement plants and refineries, although these currently use fossil feedstocks. At what rate and to what extent these plants can change to biogenic feedstocks is not known (and for the cement plant this will obviously only be possible for the fuel-related emissions). Nonetheless, in principle, these industries could also eventually attain net-negative carbon emissions.

At present, there are around 7–8 (chemical) P&P plants emitting more than 1,000 $ktCO_2$/year and around 5 CHP plants with biogenic emissions exceeding 500 kt/year, and a similar number of plants emitting around 300–400 $ktCO_2$/year. Since P&P plants have several stacks (with the major part of emissions originating at the recovery boiler), we assume an average capture of 600 $ktCO_2$/year from each plant. Similarly, we assume that on average 400 $ktCO_2$/year are captured from each CHP plant. This provides a rough estimate of BECCS ramp-up in Sweden. It is likely that this overestimates the initial development but, provided large-scale BECCS implementation takes off, it may underestimate the development toward 2045.

Based on current plans, it is assumed that it will be possible to start up the first CHP BECCS plant in 2024 (i.e., the Värtan Plant in Stockholm). For P&P power, there are fewer concrete plans and, thus, it is assumed that the first plant cannot be expected to be put in operation until late in this decade (here assuming 2027). For each industry category (P&P and CHP), it is assumed that it will take 5 years from when the first full-scale plant is put into operation until the second plant can be put into operation, owing to the time required to evaluate the operation of the first plant (i.e., the first plant is assumed to correspond to a large-scale demonstration plant for gaining experience of the whole BECCS chain: capture, transport and storage). In the optimistic scenario (**Figure 3A**), there is on average a 2.5-years lag between the projects that follow the first project, whereas in the less-optimistic scenario (**Figure 3B**) this lag is assumed to average 5 years **Figure 3** gives the results from the roadmap analysis, and it can be concluded that compared to the targets proposed in SOU 2020:4, the 2030 BECCS target seems to be challenging given the above assumptions, whereas the 2045 target seems likely to be within reach in both scenarios if applying the lower boundary of 3 $MtCO_2$/year, but obviously provided that initial ramp-up is successful.

Both scenarios obviously require a much stronger climate policy than what is currently in place, including incentives for capturing biogenic emissions (such as the reversed-auctioning system proposed in SOU2020:4). The above analysis is restricted to existing plants. Although it should be a fair assumption that most of the biogenic emission sources, which may be equipped with capture plants, will be existing plants, some biogenic fuel production processes may be added. The latter will, in turn, depend on the development of the refinery industry and on their

[8]100 $ktCO_2$/year is arbitrarily chosen as the lower limit for CCS to limit the specific capture cost (€/tCO_2), although, as mentioned above, the first projects would probably have to target larger emission sources.

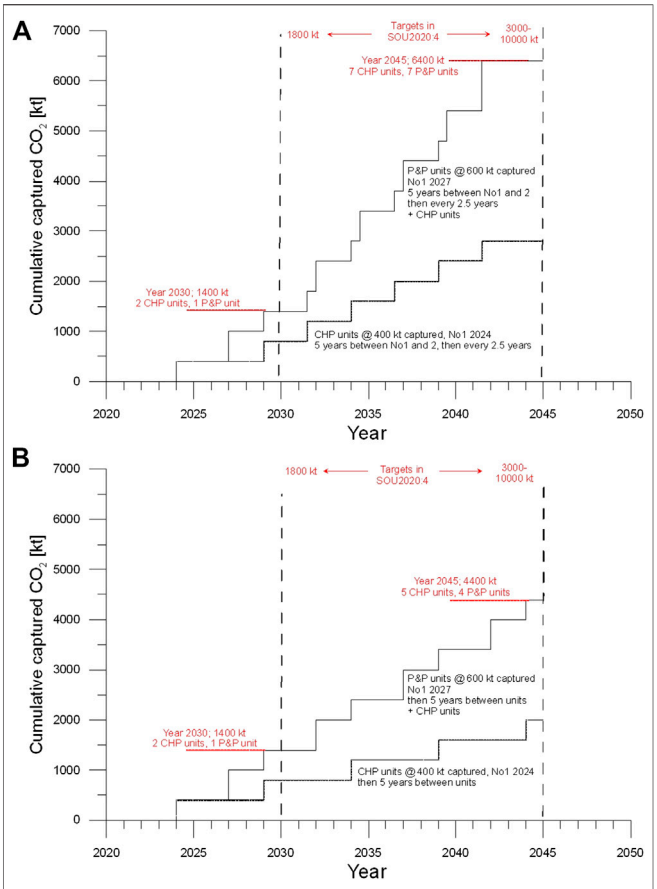

FIGURE 3 | Two schematic roadmaps for the development of full-scale BECCS projects in Sweden. These roadmaps assume the application of capture in P&P and CHP plants. The roadmaps apply the target values proposed in SOU (2020):4; 1.8 $MtCO_2$ captured is expected to result from the auctioning system by 2030, and the indicative target is to capture 3–10 $MtCO_2$ by 2045. **(A)** An optimistic scenario; **(B)** a less-optimistic scenario.

ability to transform so as to provide advanced biofuels for road, aviation and maritime transportation.

If the proposed BECCS targets were to be met solely by capturing CO_2 from the biogenic emissions from the present CHP units (**Figure 3**), this would require capture at three plants for the 2030 target (1.8 Mt/year). The 2045 target would require capture in at least five plants for the lower range given (3 Mt per year) and would basically require all large-scale CHP units to reach the upper level of removal, i.e., 10 Mt/year. If instead only P&P units are targeted, it would be sufficient to conduct capture at one or two of the largest plants for the 2030 target to be met and at three to nine plants for the range given for the 2045 target (3–10 Mt/year). These figures all assume 90% capture and cumulative addition of the captured CO_2, starting from the largest unit. Capture would most likely be applied to a mix of CHP and P&P units, as assumed in the two scenarios depicted in **Figure 3**.

In summary, the assessment of possible ramp-up of BECCS in Sweden shows that there is an urgent need to start large-scale implementation of BECCS if the targets proposed in the public inquiry (SOU 2020:4) are to be met. Most critical is to meet the 2030 target for BECCS, whereas the 2045 target should be attainable, provided that actions are instituted immediately for first implementation before 2025 and that implementation is thereafter continuously ramped up over the entire period up to 2045. These conditions and the other conditions identified as necessary in this paper are summarized in the box.

BOX | It should be technically possible to scale up BECCS to reach the recently proposed targets for 2030 and 2045 provided that the following conditions are met:

1) Action is started immediately (i.e. in 2020) for first full-scale implementation before 2025;
2) Current small-scale demonstration projects are successful in terms of technology performance;
3) The necessary incentives are put in place, i.e. incentives for mitigating biogenic emissions at a level in line with the cost of BECCS (~100 €/ton CO_2)
4) The Northern Lights Project is successful during the next few years and the necessary permits are secured;
5) Capacity and knowledge building progresses to control costs and obtain reliable capture processes; and
6) Transparent communication channels are established to deal with issues concerning public and social acceptance.

CONCLUSION

When the IPCC responded to the invitation to assess what we know and do not know about reaching a temperature goal of 1.5°C global warming above pre-industrial levels after the Paris Agreement, only a handful of 1.5°C scenarios were available, reflecting a heavy dependence on carbon removal through BECCS (Rogelj et al., 2015). During the course of the assessment, more scenarios became available–partially in response to concerns raised regarding the adverse side effects of a large-scale rollout of BECCS. On the one hand, this expanded the scenario space by excluding CCS from the mitigation mix (e.g., Grubler et al., 2018) and, on the other hand, it led to the exploration of CO_2 mitigation through demand reductions and lifestyle changes (e.g., van Vuuren et al., 2018). Still, carbon removal plays an important role in all of the pathways assessed by the IPCC (2018b), and as countries move toward formulating their own net-zero emission goals, they look to global pathways for information that these pathways are not necessarily designed to provide.[9] As key needs for national roadmaps and policy design, we identify greater granularity at the technology and supply chain levels, geologic storage suitability, and feasibility with respect to interactions with other SDGs. In addition, there needs to be consideration of the current and envisaged policy mixes, which are also influenced by the political economy and other non-climate factors. More scenarios to test the impacts of

[9]Looking into the future, greater sectoral detail is foreseen to emerge in the literature. This could facilitate progress on reconciling the top-down modeling with the bottom-up analysis.

different governance approaches and legal constraints are required. Finally, co-design and participatory approaches should be considered to capture bottlenecks and opportunities associated with social acceptance. While such participatory approaches are often called for (e.g., Cox et al., 2018) in the context of BECCS deployment, there are doubts that this is compatible with expensive, technologically advanced CDR proposals, which are typically non-participatory and centralized (McLaren, 2016). With these caveats in mind, there are some experiences gained from other activities, such as participatory integrated assessments of the social acceptance of wind energy (Scherhaufer et al., 2018), which could at least conceptually serve as a template. Future research should look into possible analogues in the context of mitigation to allow for the development and refinement of such approaches.

To assess the extent to which the top-down expectations of BECCS can be fulfilled, there is an urgent need for national bottom-up assessments that include evaluations of the technical, economic, policy and social aspects. Such an analysis should as a first step focus on regions with well-developed biomass markets, such as those originating from forest industries. Here, Sweden is used as an example, on the basis that it has a well-developed forest industry and many large, existing biogenic emission sources from the P&P industry and CHP plants. These conditions, combined with Sweden's ambitious goal of reaching net-zero GHG emissions by 2045 and becoming a net-negative emitter thereafter, clearly indicate a role for carbon removal in the Swedish climate change mitigation mix. In this study, we demonstrate that Sweden has considerable potential for removing CO_2 by capturing biogenic emissions and storing them geologically. Despite the favorable conditions, we identify an implementation gap. An analysis of the factors that inhibit BECCS implementation along the dimensions of technology and systems, governance, economics and policy, and acceptability shows that–discrepant with commonly held beliefs–the most substantial barriers are not of a technological nature. Indeed, the components of BECCS are technologically mature, the forest management systems for producing Swedish biomass are long-established, and productive and sustainable post-combustion capture has entered higher TRLs, although experience from larger-scale application at Swedish emission sources is lacking. Moreover, the transport of CO_2 is a known and commercially available technology, and storage is being outsourced to Norway, which has a long-time practical experience. Unlike other European countries, societal acceptance, legal constraints and political uneasiness with respect to both bioenergy and CCS seem to be less prominent barriers, even though the assessment in *Incentives* shows very clearly that knowledge remains too fragmented to draw robust conclusions on this issue. In addition, contentions can be identified when zooming into the different components of the BECCS chain, as exemplified by the controversy related to expanding biomass supply from forestry vs. maximizing the carbon stock of the standing forest or the geopolitical uncertainties associated with the dependence on Norway for geologic storage, as discussed in detail in *Incentives*. It has to be stressed that regarding social preference, the literature is sparse and there is a need for targeted Swedish surveys to attain a more refined understanding of whether any of these issues could be show-stoppers and to determine whether the impacts of other aspects have been underestimated.

Major uncertainties remain regarding the dimensions of governance, economics and policy that lead to disincentives for implementing BECCS. An important policy aspect is discovering a way to establish coherence between fossil fuel pricing and valuing carbon removal, while still offering enough support to close the implementation gap in a rapidly closing time-window. This is also important, since a criticism that has been directed toward BECCS is that it could postpone efforts to reduce fossil fuel emissions (Minx et al., 2018). Therefore, a coherent policy is needed for fostering the acceptability of BECCS in a more fundamental manner. Estimates of two Swedish roadmap scenarios for ramping up BECCS to meet recently proposed targets for 2030 and 2045 indicate that it should be possible to meet the targets, although this will require: 1) urgent action; 2) that the current small-scale demonstration projects will be successful; 3) that the necessary incentives are put in place; and 4) that the Norwegian plans to develop a storage infrastructure are successfully executed during the next few years (the Northern Lights Project) and that the necessary permits are secured. In addition, there will be a need for: 5) capacity and knowledge building to control costs and obtain reliable capture processes, which is likely to depend on the international diffusion of CCS and BECCS technologies; and 6) transparent communication to deal with emerging issues concerning acceptance of the technology.

In light of the prominent role of BECCS in global scenarios that limit warming to well below 2°C and the maturity of the BECCS technology, the main implications from this analysis are that–despite sustainability concerns about a large-scale, global BECCS rollout - there is a strong need for national bottom-up assessments of possible roadmaps for BECCS, which consider emission sources, transport and storage infrastructure, social acceptance, and economy-wide and environmental effects. From this follows the recommendation that, provided the national analysis identifies a reasonably strong potential for sustainable BECCS, economic incentives should be put in place, such as the reverse-auctioning system proposed for Sweden. Furthermore, comprehensive policy packages need to account for the high value of forestry-derived products and the potentially increased competition between sectors (for which biomass can be a mitigation option), most notably the transportation, chemicals and energy sectors. In addition, investments will be delayed if policy uncertainties are not resolved, so a clear commitment to BECCS implementation needs to be signaled to investors, who–under the current premise of first needing to seek EU support, the materialization of which is not clear–face significant uncertainty with respect to their planning. This will be the case unless the proposed auctioning system is indeed implemented, mitigating the difference between any EU support and the cost for BECCS. In the first place, this will require harmonization of definitions, accounting and governance. Finally, a pathway that involves transformative investments is vulnerable to unforeseen events, as experienced during the current economic crisis associated

with the COVID-19 pandemic. Policy packages must be stress-tested for external shocks, to give robust signals to investors.

This study has taken the first step toward demonstrating that additional analyses at the national level are needed to close the implementation gap that we observe when comparing climate ambition with actual CDR deployment (in this case, BECCS). While the global pathways offer a sound basis for the UNFCCC debate and an understanding of the different avenues to reach ambitious global temperature goals, more analysis in the context of individual countries is needed, as they move toward their own net-zero emissions goals and the implementation thereof.

Whether or not the lessons learned from the Swedish case study can readily be generalized to other countries remains to be seen. Evidently, countries with similar conditions are more likely to learn from this case study. How similar the countries and their situations are will be difficult to determine without further research. Technical potentials might be more readily available and assessable than insights into current industry and policy processes, and societal acceptance (Nemet et al., 2018). With this caveat in mind, there are several insights that we want to flag as particularly useful for other countries' net-zero considerations: 1) global studies can provide general guidance on the required ramp-up, although they may disregard local opportunities and tradeoffs and should, thus, be accompanied by national analyses without excluding options that are contentious (or not) at Gigatonne-scale; 2) while BECCS is based on comparatively mature technologies, it will require immediate political and economic incentives to be ramped up sufficiently quickly in countries that feature sustainable and socially acceptable BECCS pathways; 3) adopting a value chain perspective and looking more into new "climate-positive" products linked to BECCS can open up alternative or complementary economic entry points to technology rollout; 4) societal preference is as important as technical feasibility when moving to implementation, yet this is where the largest knowledge gaps arise in the context of BECCS and CDR, more generally; and 6) the rapidly closing time-window for reaching the ambitious Paris Agreement targets may call for hybrid approaches to governance, whereby local BECCS ramp-up could proceed more readily while cross-jurisdictional issues (e.g., related to the sustainability of biomass imports or accounting for emissions removal) could be governed at higher levels. This would also apply to other CDR approaches that might prove more amenable in other countries.

DATA AVAILABILITY STATEMENT

Publicly available datasets were analyzed in this study. This data can be found here: https://data.ene.iiasa.ac.at/iamc-1.5c-explorer/; https://doi.org/10.1016/j.ijggc.2018.06.022; https://research.chalmers.se/en/publication/509912. The data on the IPCC SR1.5 pathways are available at IIASA's scenario explorer.

AUTHOR CONTRIBUTIONS

SF and FJ conceived the study together. SF led the scenario and implementation gap analysis, while FJ led the work on the Swedish case. Both authors discussed and interpreted the results and jointly wrote the paper.

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REVIEW
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Different This Time? The Prospects of CCS in the Netherlands in the 2020s

Sanne Akerboom[1], Svenja Waldmann[1], Agneev Mukherjee[1,2], Casper Agaton[3], Mark Sanders[4] and Gert Jan Kramer[1]*

[1] Copernicus Institute of Sustainable Development, Utrecht University, Utrecht, Netherlands, [2] Organic Chemistry and Catalysis, Debye Institute for Nanomaterials Science, Utrecht University, Utrecht, Netherlands, [3] Utrecht School of Economics, Utrecht University, Utrecht, Netherlands, [4] School of Business and Economics, Maastricht University, Maastricht, Netherlands

Carbon Capture and Sequestration (CCS) has been recognized as an important means of mitigating global climate change, but apart from several pilots, it has not yet been successfully implemented on the large scale needed to live up to the expectations as a mitigation method. In Netherlands, the option of CCS has been the subject of debate for a long time, as three unsuccessful projects – two onshore in Barendrecht and the Northern regions, and one offshore near the Port of Rotterdam – demonstrate. Nevertheless, CCS has been accorded an important place in the current Dutch climate policies, being expected to contribute up to 7 Megaton of CO_2 reduction. This is reflected in a fresh crop of CCS project plans. For the most, these plans have a long way to go from the drawing board to actual operations due to the technical, economic, legal and societal challenges ahead. In this article we review the status and possibilities of CCS in Netherlands based on an analysis of existing literature in the relevant disciplines. First, a brief overview of the technology options for carbon capture and storage or utilization is given. This is followed by a detailed analysis of the governmental support for CCS, given the vital role that fit-for-purpose legal frameworks and policy instruments will play in CCS deployment. Technical, legal and policy uncertainties translates into factors inhibiting CCS investment and so the paper then presents a CCS investment project to illustrate how such risks affect the business case for CCS. Finally, bearing in mind that societal acceptance has proved to be a major barrier for CCS, both in Netherlands and elsewhere, the conditions that enhance public acceptance of CCS are examined. Our work shows that while CCS is technically a straightforward proposition, its deployment has historically been hindered by the lack of a sound business case and a compelling and stable socio-technical narrative. The main argument in favor of CCS today is that it offers a transition pathway for rapidly and massively reducing CO_2 emissions beyond what could be accomplished by alternative methods like electrification and renewable fuels in near future. The introduction of new financial instruments, increased government support and an improvement in social engagement appear to have enhanced the prospects of CCS in Netherlands, but we feel it is premature to assume that this time everything is different.

Keywords: carbon capture and storage (CCS), carbon capture and utilization (CCU), sustainability, uncertainties analysis, climate action plan 2030+

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Andres Fernando Clarens,
University of Virginia, United States
David S. Goldberg,
Columbia University, United States

****Correspondence:***
Sanne Akerboom
s.akerboom@uu.nl

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INTRODUCTION

With the Paris Agreement of UNFCCC (2015), the community of nations has committed to the very ambitious *global* target of keeping temperature rise below 2°C, and preferably to 1.5°C. This target can only be reached when *national* greenhouse gas (GHG) emission reductions add up to the required global reduction. The current set of pledges (the so-called Nationally Determined Contributions) are far from the Paris goal (IPCC, 2018). A step change in national ambitions, along with credible plans for their implementation, is therefore needed.

In this spirit, in 2017 the newly elected government of Netherlands set an ambitious target for 2030, of reducing national CO_2 emissions by 49% relative to 1990. This requires 48.7 Megaton (Mt) of additional reductions compared to the baseline outcome of existing policies (PBL, 2019b). These targets have been laid down in a *Klimaatwet* (Climate Act) and the public-private *Klimaatakkoord* (Climate Agreement) negotiated in 2018–2019 sets out the pathway to sustainability (Klimaatakkoord, 2019; Klimaatwet, 2019).

Carbon Capture and Sequestration (CCS) is an important instrument in the *Klimaatakkoord,* providing proposed emissions reductions of up to 7.2 Mt annually until 2030, second in importance only to the contribution of new renewables (see **Figure 1**).

In recognition of the magnitude of the challenge, mitigation measures are typically driven to their plausible maximum. The deployment of CCS, however, comes with multiple restrictions. On the one hand, CCS can make a large contribution to mitigation but, on the other hand, there is a reluctance to embrace the technology – that is: to cap supporting subsidies for its deployment before it has even begun. This wavering attitude has strongly influenced the case for CCS in Netherlands in earlier decades. This prompts the question in the title of this paper: Different this time?

Whilst this paper presents a case study of CCS in Netherlands, it will also shed light on the challenges facing CCS deployment globally. Netherlands, with its ample on- and offshore storage capacity in depleted natural gas fields, its well developed infrastructure and excellent knowledge base and well-functioning institutional framework, is globally perhaps best positioned to pioneer this technology. One might say that if CCS does not succeed in Netherlands or in Norway, it is hard to imagine where it would have a better chance. This is concerning, the successful global rollout of CCS on a massive, gigaton per annum-scale, is essential to meet the global climate target and limit global warming to 2°C or below. As evidence of this, three of the four scenarios in the IPCC's 1.5°C report from 2019 include CCS (IPCC, 2018).

To examine whether CCS deployment in Netherlands can be successful, we distinguish between three important stakeholders: government, business (industry) and society. As we will show below, society has been an important factor in blocking onshore CCS projects (Brunsting et al., 2011; Kuijper, 2011; Terwel and Daamen, 2012; van Os et al., 2014; van Egmond and Hekkert, 2015). From the ROAD project we have learned that businesses will not invest in CCS unless there is a viable business case (Read et al., 2019), and subsidies are not enough by themselves to build a solid business case on alone. Generally, it has also been found that CCS projects slow down due to insufficient support from the government (Karimi, 2017). Therefore, we will highlight the role of each of these stakeholders towards successful implementation of CCS in Netherlands in the 2020s.

In the subsequent sections of this paper we look at the case for CCS from different perspectives: technological (Section "Technology Options: CCS, CCU, and CC(U)S"), governmental (Section "Governmental Support for CCS"), economic (Section "Investment Uncertainties of CCS"), and societal (Section "Societal Acceptance of CCS"). In the final section "Analysis – Different This Time?" we draw some tentative conclusion about the fate of CCS in the coming decade and point out what we see as the most critical aspects. First, however, we start with a short history of CCS in Netherlands.

A BRIEF HISTORY OF CCS IN NETHERLANDS AND EUROPE

Netherlands is geographically and economically well positioned for CCS. The large natural gas reserves that have been exploited since the 1950s provide suitable storage capacity close at hand. The Dutch industry is both energy intensive and geographically concentrated in a few industrial districts, such that transport and capture can benefit from economies of scale, scope and agglomeration. This is similar to Norway, which has a long history of CCS pilots and demonstration projects. Despite all these advantages, to date no industrial scale CCS projects are operational to date.

In this section we recap the recent history of CCS in Netherlands by describing the course of events for the three Dutch CCS projects that were proposed, and in two cases abandoned or reshaped.

The First Dutch CCS Project Plans (2000–2017)

In recent history, Netherlands has attempted three CCS projects: two onshore in Barendrecht and the Northern regions and one offshore near the Rotterdam Port. None of the projects were realized because of a combination of societal, political and funding challenges.

The onshore CCS project in Barendrecht faced societal resistance. In 2008, Shell Global Solutions International B.V. won a government tender to store approximately 10 Mt CO_2 over 25 years (0.4 Mt/year) from Shell's refinery near Rotterdam in a subsurface natural gas reservoir close to the Barendrecht, a suburb of Rotterdam. The project was seen as being technically straightforward, and the main aim of Shell and the government at the outset was to test the legal and regulatory frameworks

Abbreviations: CCS, carbon capture and storage; CCU, carbon capture and utilization; CCUS, carbon capture utilization and sequestration; CFPP, coal-fired power plants; EII, energy intensive industry; EU, European Union; ETS, emission trading system; PBL, environmental planning agency; GHG, greenhouse gas emissions; Mt, megaton; OM, operations and maintenance; ODE, opslag duurzame energie; SDE+++, stimulating sustainable energy.

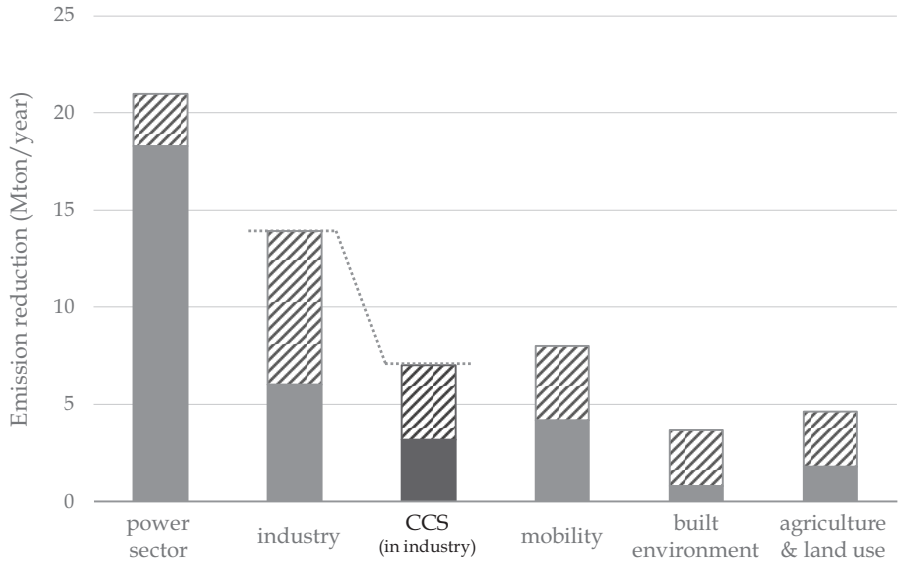

FIGURE 1 | Projected annual emission reductions in Netherlands in 2030, based on the Dutch 2019 Klimaatakkoord, according to analysis of the Dutch Environmental Planning Agency (PBL). The Klimaatakkoord allocates the emission reduction task to five sectors of the energy economy (gray). CCS is part of industry. The hashed areas indicate the uncertainty between low and high estimates for 2030 (PBL, 2019a).

for CCS, as well as the monitoring and verification procedures (Lockwood, 2017). The examination of possible local concerns, on the other hand, was not given sufficient consideration prior to the announcement of the project (Ashworth et al., 2012). Right after the selection of the project by the Minister of Economic Affairs and a first public hearing in Barendrecht, critical questions were raised about safety issues and negative impacts on human health and the environment. Horror stories of a CO_2 blowout from the subsurface became part of the narrative in the media presence (Feenstra et al., 2010; Lockwood, 2017). Due to this increasingly negative perception of CCS by the broader public, the project was put on hold and additional studies were requested. At the same time earthquakes caused by the production of natural gas from subsurface reservoirs occurred close to Groningen. The rather technocratic and legalistic approach of the industrial stakeholders and policy makers allowed the situation to get out of hand. Emotions cannot be assuaged with facts and scientific studies, and political parties were not prepared to lose political capital and votes over the project. Around 2010, close to the general election of a new Parliament, political support fell away, resulting in the cancelation of the project (Brunsting et al., 2011; Kuijper, 2011; Terwel and Daamen, 2012; van Os et al., 2014; van Egmond and Hekkert, 2015).

Around the same time, another onshore CCS project – Nothern Netherlands CCS initiative – was undertaken, although this project was canceled quickly after its presentation. Although this project also met with local opposition, van Os et al. (2014) found that this was not solely responsible for the abandonment of the project. No clear organizational division of tasks and responsibilities could be established, and the current legal and governance framework was found to provide insufficient to provide guidance. This was also mentioned as an important element for the failure of CCS project close to the port of Rotterdam (ROAD project) (Warmenhoven et al., 2018).

The failure of two onshore CCS projects shortly after each other made clear that making CCS a reality in a densely populated country like Netherlands is more than an engineering problem. As a consequence of these events, the focus of CO_2 storage shifted away from onshore to offshore.

The third Dutch CCS launch project, the ROAD project, was conceived in the early 2010s, and was a joint attempt by E.ON Benelux and Electrabel Nederland (now Uniper Benelux and Engie Nederland, respectively) to demonstrate the technical and economic feasibility of large-scale and integrated CCS. It aimed at offshore storage of 1 Mt of CO_2 per annum, to be captured from the newly built coal-fired power plant (CFPP) Maasvlakte 3. In the ROAD project, CO_2 would be transported via existing gas pipelines to two offshore (condensate) natural gas fields located in shallow water 20 km offshore in the North Sea, northwest of the CFPP. The storage capacity of both fields was estimated to be more than 10 Mt CO_2. Since the project would repurpose an existing pipeline to a depleted gas field, the transport and storage part of the ROAD project was ready to go, while a 1.1 Mt/year facility for flue gas (post combustion) capture had been designed. In fact, the permission to build the Maasvlakte 3 power plant was conditional on it being capture-ready so that the plot space and tie-ins were available (Read et al., 2019). Although the Maasvlakte Power Plant 3 came online in 2015 (Lockwood, 2017), the CCS element of the project was mothballed in 2014 due to a lack of clarity on financing (Carbon Capture and Sequestration Technologies Program at MIT, 2016). Finally, Uniper and Engie decided to withdraw from the project in 2017 citing the lack of political support and a sustainable business case for coal-fired power generation in combination with CCS, leading to the

cancelation of the project (NLOG, 2017; Port of Rotterdam, 2017; Read et al., 2019).

The Current Crop of Dutch and European CCS Projects

In Europe, only two large-scale storage projects are operational; both of them in Norway. They are the Sleipner project in the norther North Sea, 250 km west of Stavanger and the Snøhvit project in the Barents Sea, north of Hammerfest. Between them, 1.7 Mt CO_2 per year is stored. For both projects, the CO_2 comes from natural gas production. Natural gas from the Sleipner field contains up to 9% CO_2, and that from the Snøhvit field 5-6%. The CO_2 is separated prior to the purified natural gas being injected in the gas grid (Sleipner) or liquefied (Snøhvit) (IEAGHG, 2016).

In Europe (United Kingdom, Norway, Ireland, and Netherlands) ten large-scale CCS facilities are currently on the drawing board and/or in different stages of development, intended to be operational in the 2020s. Facility industries related to these operations are of different nature, ranging from power generation and hydrogen production to natural gas processing and oil refining. When operational, these facilities combined will capture 20.8 Mt CO_2 per year (Global CCS Institute, 2019).

The Porthos project in Netherlands is one of the most advanced European CCS projects under development. A joint project between the Port of Rotterdam Authority, Energie Beheer Nederland B.V. (EBN) and Nederlandse Gasunie N.V., Porthos envisages various companies supplying their CO_2 to a collective pipeline running through the Rotterdam port area. It thus offers the possibility of combining CO_2 capture from clusters of industrial installations with shared infrastructure in the Port of Rotterdam. The project initially aims at storing 2 Mt CO_2 per year, with the possibility of increasing capacity to 5 Mt CO_2 per year by 2030 (Gasunie, and EBN, 2018).The storage location is the same depleted offshore natural gas field previously targeted by the ROAD project. The final investment decision is expected in 2021, with CO_2 storage under this project expected to start by end-2023 (Rotterdam CCUS, 2019).

Two other projects (Athos and Aramis) are currently under development in Netherlands. Like Porthos they combine CO_2 capture with for the development of shared infrastructure and storage facilities. The Athos project – a consortium of EBN, Gasunie New Energy, Port of Amsterdam and Tata Steel IJmuiden – explores Carbon Capture Utilization and Sequestration (CCUS) opportunities in the Noordzeekanaal industrial cluster and has the ambition of storing up to 7.5 Mton CO_2 per year in offshore subsurface reservoirs (IOGP, 2020). The Aramis project is being developed by a consortium of the Nederlandse Aardolie Maatschappij B.V., Total, and EBN for the port of Den Helder in the north of Netherlands. The project was launched mid-2019 and a feasibility study for offshore CO_2 storage is now being conducted (IOGP, 2020). While the start date and capacity have yet to be decided, the existing infrastructure can potentially accommodate a 10 Mt/y project (van Bracht and Braun, 2018). Another project in the early-development stage is the Hydrogen 2 Magnum project. A joint venture between Equinor, Vattenfall and Gasunie, the project will involve the conversion of natural gas to hydrogen (blue hydrogen), which will be used in the Dutch gas-fired power plant Magnum in Eenshaven. The resultant carbon dioxide will be stored in the Norwegian Sleipner field (Equinor, 2020).

Among them, these projects now cover the larger industrial clusters with access to offshore natural gas reservoirs. If implemented, the storage capacity would exceed the agreed volumes of captured and stored CO_2 as given in the Dutch Klimaatakkoord. However, the projects have a long way to go from the drawing board to actual operations. There are technical, then economic and finally legal and societal challenges ahead.

TECHNOLOGY OPTIONS: CCS, CCU, AND CC(U)S

Overview of the CCS Technology Development

Carbon capture and sequestration implementation faces several challenges on various fronts, such as social acceptance and buildup of a sound business case as earlier projects have shown in Netherlands. Technologically, however, in-depth knowledge of the different constituents of CCSare well in place, although further CCS processing is needed for site specific developments. Here, we provide a short overview of the technology status of CCS, before considering the prospects of a more recently proposed CCS alternative, Carbon Capture and Utilization (CCU), as well as its combination with storage (CCUS or CC(U)S).

The first step in carrying out CCS is capturing CO_2 from industrial plants, for which numerous technological alternatives exist. The choice of the respective capture technology depends on various factors such as the CO_2 concentration in the capture gas stream, the pressure, the fuel type, and whether the plant is a retrofit or greenfield (i.e., fully new-built) development. In the context of CO_2 capture from power plants, post-combustion capture is the most well-developed technology, which can be retrofitted to already existing plants (Leung et al., 2014). However, the main challenge for post-combustion capture is the high energy load that is needed to capture significant amounts of CO_2 from the flue gas. The cause lies in the low concentration of CO_2 in powerplant flue gas (4-14 %) (Olajire, 2010). This is exacerbated by the need to raise purity of the captured CO_2 to 95% or higher for pipeline transport (de Visser et al., 2008). For other industrial plants, pre-combustion capture is the leading option. Here, CO_2 is captured from the reformate stream by steam methane reforming, which is the main industrial process for hydrogen (H_2) production. The much higher CO_2 concentration (15-60 %) facilitates the CO_2 separation as compared to post-combustion capture (IPCC, 2005).

Two additional options must be mentioned, both less mature than the above capture technologies. The first is pre-combustion capture from solid fuels,such as coal or biomass. Here the fuels are first gasified using partial oxidation or steam reforming to a mixture of mainly carbon monoxide (CO) and H_2. With the addition of water vapor (H_2O) the CO is converted into CO_2

and additional H_2, with the CO_2 being captured (Olajire, 2010). The second option is oxyfuel combustion, a modified post-combustion capture method where pure oxygen is used instead of air as the combustion medium. This process significantly increases the CO_2 concentration in the flue gas to >80 % by eliminating the nitrogen content (Olajire, 2010; Leung et al., 2014). The large quantity of pure oxygen required is the major disadvantage, raising both capital costs and energy penalty.

In addition to the capture technology, the separation technology also affects the costs and energy penalties. Physical and chemical absorption, adsorption, cryogenic distillation, membrane-based separation, hydrate-based separation have been researched, with their suitability depending partly on the capture technology used (IPCC, 2005; Olajire, 2010; Leung et al., 2014).

On the transport front, pipelines are the most cost-effective option for large-scale, long-distance CO_2 transport. The CO_2 is transported in supercritical state with gas pressure above 7.4 MPa and a temperature of 31.1°C (WorleyParsons, 2009). Fracture-tough steel is mandatory for the pipelines, and intermediate compressor stations may be needed to guarantee the required pressure and temperature (WorleyParsons, 2009). Overall, pipeline transport of CO_2 is very similar to that of any other hazardous liquid or gas. In case the CO_2 capture point does not have ready access to pipeline facilities, railroads or truck tankers may be used, while ship tankers similar to those used for liquefied natural/petroleum gas can be used for offshore transport (IPCC, 2005; WorleyParsons, 2009).

CO_2 storage in geological formations is realized by injecting CO_2 to depths greater than a few hundred meters, with low permeability caprock and other geological trapping mechanisms preventing the escape of the gas towards the overburden. The well-drilling and injection technology, computer simulation of the storage reservoir performance, and required monitoring methods are similar to those already in use in the oil and gas industry (IPCC, 2005).

Development, Restrictions, and Opportunities for Large-Scale CCU

From a techno-economic perspective, storage became challenged because of the seeming incongruity of expending large sums of capital to capture CO_2 and then storing it underground, thereby foregoing to opportunity to re-use the carbon and 'close the loop'. This has given rise to the idea of carbon utilization. With CCU, the captured CO_2 is used as a 'renewable' raw material instead of being treated as waste, potentially making CO_2 capture economically desirable rather than merely an unprofitable addition to the project cost (Cuéllar-Franca and Azapagic, 2015). As a CO_2 mitigation option, however, the potential of CCU depends on its definition. The use of CO_2 as a chemical building block or building material can allow long-term removal of CO_2 from the atmosphere, but such use is likely to account for under 10% of worldwide CO_2 emissions (von der Assen et al., 2014; Chauvy et al., 2019). The synthesis of fuels like methane and methanol, on the other hand, can permit far larger scale CCU deployment at the cost of a shorter CO_2 cycle. Some projections state that technology mixes incorporating CCU fuels (electrofuels) can allow climate change targets to be met at far lower costs than full electrification scenarios (IOGP, 2019). This optimism needs to be balanced against the fact that CCU fuels are today far more expensive than their fossil fuel counterparts (Dimitriou et al., 2015; Pérez-Fortes and Tzimas, 2016; Cuéllar-Franca et al., 2019; Kraan et al., 2019). The chemical inertness of CO_2 means that aids, either as direct energy supply or in the form of energy-rich co-reactants, are generally needed to convert it into useful products (Porteron et al., 2019). This alters the total energy balance and reduces the potential for GHG mitigation of CCU options. Indeed, an implicit assumption in CCU deployment is the availability of sufficient quantities of cost-effective renewable energy. While the substitution of energy-rich compounds with CO_2 in a process chain can lead to increased energy efficiency, CO_2 conversion into compounds such as hydrocarbons necessitates the use of renewable energy for this approach to be superior to conventional petrochemical technologies (Porteron et al., 2019). CO_2 is already used as a raw material in certain industries, but only urea production can be considered to be a commercial-scale deployment of CCU (Fortunato, 2018).

In the near term, therefore, progress on CCU is expected to concentrate on matching large point sources of concentrated CO_2 with large-scale consumers. While the power sector is the largest CO_2 emitting group, the low concentration of CO_2 in powerplant flue gas (4-14 %) requires the handling of a large volume of gas, increasing equipment size and costs (Olajire, 2010). Industries such as ammonia and hydrogen production, or steel production using the HIsarna process, produce large flue gas streams of almost pure CO_2, and these may therefore be more suitable initially for CCU implementation.

In the Dutch context, the use of CO_2 in horticulture (up to 2.1 MT/y by 2030) has been pitched as an enticing near-term CCU option (Croezen et al., 2018). As the CO_2 that is sequestered in plants is soon released back into the atmosphere, this is not considered as a CO_2 reduction in CO_2 accounting practices. However, the use of captured CO_2 in horticulture can still lead to net avoided CO_2 emissions of 300–950 kg CO_2 per ton of CO_2 captured, because it will replace the current practice of burning natural gas to generate fresh CO_2 for use in greenhouses (Croezen et al., 2018). Other potential non-fuel CCU applications in Netherlands are much more limited in scope. Carbonate mineralization is only expected to account for a maximum of 200 kT/y even in the long-term, although this ultimately depends on the availability of waste streams like steel slag and fly ash. Likewise, the potential for CO_2-based polymers is unlikely to surpass 50 kT/y unless novel markets for these polymers arise (Ecofys, 2017).

The total non-fuel CCU potential in Netherlands has been estimated as being of the order of 1.7-3 MT/y by 2030 (Krebbekx et al., 2012; Ecofys, 2017; Porteron et al., 2019). The magnitude of the discrepancy between this figure and the total CO_2 availability can be understood by considering that the CO_2 emissions resulting from fuel consumption in just the Dutch energy and manufacturing industries and construction amounted to 87.7 GT in 2018 (RIVM, 2020). Nevertheless, the development of a CO_2 supply grid can start with 'low hanging fruit' applications like

horticulture and chemical synthesis, before being extended to larger-scale, longer-term CCS applications. Since the production of substantial quantities of electrofuels is only expected to be viable post-2040 (Malins, 2017; Searle and Christensen, 2018; Kranenburg et al., 2020), CCS is, as a minimum, a significant bridging solution until the time that CCU can realistically be expected to reach scale.

For CCU deployment, the first thing to consider is the location and size of the potential carbon sources and sinks. In Netherlands, the major point sources for CO_2 emissions are located along the coast in the provinces of North Holland, South Holland and Zeeland. These include the Tata Steel plant in IJmuiden, the YARA Sluiskil fertilizer and chemicals plant and the Dow Benelux chemical plant in Hoek. Linking these concentrated CO_2 emissions sources with potential CO_2 sinks in the vicinity would therefore be a logical first step, although this should be done keeping in mind that trends such as an increase in renewable energy use and energy efficiency may lead to a decline in the availability of these sources in the future. The major emitters in the Randstad region are in relatively close proximity to chemical plants that could act as their customers for CO_2. For instance, the 45 chemical companies based in the Rotterdam-Rijnmond cluster have traditionally used petrochemical feedstock (Stork et al., 2018), but recycled CO_2 from the nearby steel plant or power stations could be used in the methanol-to-olefins or urea plants that are present here.

Beyond this, the prospects of Dutch non-fuel CCU are unclear. For a start, there is a need for more comprehensive and accurate statistics regarding carbon flows in the Dutch economy. It has been estimated that only 63% of domestically produced carbon products stay in the Dutch economy, the rest being exported (Rutten, 2020). Even if the majority of these remaining products are reclaimed and subject to mechanical and chemical recycling, it is clear that there will be a serious shortfall in the local availability of recycled feedstock. CCU can potentially plug this gap, but whether this is techno-economically practical needs to be determined based on a granular examination of the application and its scale, which can only be done in the presence of more robust data. As things stand today, it seems fair to conclude that CCU will remain for a long time a niche application, at best a small adjunct to large-scale CCS deployment, albeit one that is likely to grow and to ultimately (post 2050) overtake CCS. This is, we believe, the balanced technical perspective on CC(U)S.

GOVERNMENTAL SUPPORT FOR CCS

As evidenced by the description of the previous CCS project plans in Netherlands, the government is an important stakeholder in the successful implementation of CCS. The governments can employ different roles and policy instruments to enable, stimulate or to impose CCS projects (Slagter and Wellenstein, 2011). On the one hand, it can enable CCS projects by providing legal frameworks and it can further stimulate CCS by providing financial incentives. If necessary, for example when emissions reduction progresses too slowly, the government could also set obligatory binding reduction targets for sectors or companies. Here they have a choice of either creating technology-neutral obligations, or of mandating specific options, like CCS. If sectors or companies fail to meet their obligations, governments can enforce compliance by means of financial punishments. So far, the Dutch government has steered clear of creating obligations, but it has implemented legal rules and introduced several financial instruments. These we will discuss in this section.

Enabling CCS by Means of Fit-for-Purpose Legal Frameworks: EU and Dutch Rules

Law is a crucial factor in enabling CCS deployment (Lipponen et al., 2017), because it can create an appropriate governance-structure, with clear roles, tasks and responsibilities while removing legal barriers. On a higher level, the European Union (EU) regulation is relevant for the Dutch legal framework. The CCS directive (2009/31/EC) contains important rules aimed at safeguarding safety and health conditions applicable in all member states as well as minimum requirements for storage permits, liability and roles and tasks. Furthermore, it can introduce necessary legal instruments, such as permits, rules concerning the protection of health and environment and rules for liability, for instance, in case of CO_2 leakages.

The EU however emphasizes that the development of CCS "should not lead to a reduction of efforts to support energy saving policies, renewable energies and other safe and sustainable low carbon technologies, both in research and financial terms" (consideration 4). The EU determines that CCS is the permanent containment of CO_2, with care taken to eliminate negative effects and any risk to the environment and human health as far as possible (article 1). According to the directive, the decision to employ CCS is decision of member states. Neither the Directive nor the Dutch Mining Act explicitly regulate (management and maintenance of) transportation, or pipelines. This suggests that operators have freedom in determining the conditions of transportation. Under certain circumstances, however, third-party access to this infrastructure must be permitted (article 21), yet the Dutch Mining Act contains no rules guaranteeing this access.

Member states can create additional requirements, depending on the national context. Netherlands has implemented the CCS directive into chapter 3 of the Mining Act. Below we will give the most important rules.

Roles and Tasks

The CCS directive identifies a number of roles and important tasks,: operator and as regulator. The storage operator is responsible to continuously monitoring the CO_2 injection facilities, the underground storage complex and if necessary the surrounding environment to detect irregularities during operation and after closure of the storage site (article 13). The operator has to report on the results of the monitoring (article 14). Furthermore, the member states have to organize a inspections by competent authorities (article 15). The minister of Economic Affairs and Climate Policy is responsible for handling applications for permits, dealing with monitoring and liability

costs, as well as closure of the site. He is also responsible in taking over accountabilities after closure.

Permits

Operators are required to obtain permits for exploration of potential storage sites as well as storage facilities (articles 5 and 6 CCS Directive). In order to obtain a permit, an operator must be financially sound, and provide proof of financial security (article 19). It must be moreover technically competent and able to reliably operate and control the site. A permit may also be withdrawn; in case CO_2 leakage towards the overburden occurs or if significant irregularities occur (article 11). The permit can contain additional conditions, for instance relating to the total amount of CO_2 stored.

According to the Dutch Mining Act, the Minister of Economic Affairs and Climate Policy grants the storage permit. An applicant of a permit must provide relevant information, such as a time frame for the injection of CO_2, characteristics of the storage site and risk management procedures (articles 31b and 31d). Once the minister has received an application for a permit, other parties will have the opportunity to also submit an application for the same area. The minister then decides, on the basis of the information provided in the applications, who will be granted the permit. This means that an exploration permit, leading to the identification of a suitable site, does not guarantee a storage permit.

Leakages and Liability

In case leakage or significant irregularities occur, the operator has to notify the competent authority, in the Dutch case the Minister of Economic Affairs and Climate Policy, and take necessary corrective measures. In case the operator is unable to do so, the competent authority will take over (article 16). In this case, the operator has to surrender emissions allowances under the Emissions Trading System (ETS) (Directive 2009/29/EC, 2009) for resulting emissions into the atmosphere for at least 20 years after obtaining the permit, or after closing the storage site (see below). However, in Netherlands the minister can decide to shorten or prolong this, albeit that the Mining Act does not provide any indicators for how this will be decided upon. This is therefore an uncertainty also with respect to ETS liability.

Liability for damages to the environment is dealt with by means of the Directive on Environmental Liability (Directive 2004/35/CE, 2004) and damage to health and property is dealt with at the member state level. In Netherlands, this is regulated by means of the Dutch Civil Code (article 6.162 and 6:174-177). These provisions are general and do not pertain to CCS specifically. The length of liability for damages under these provisions differs from between 5 years after discovery of the damage to 20-30 years after the activity has caused damages. However, after a period of 30 years any liability under the Dutch Civil Code ends.

Closure of Storage Sites

When the conditions of the permit are met, for instance relating to the volume of CO_2 stored, the storage site will be closed permanently. Upon closure, a post-closure plan is required, which has to be approved by the authority. In the case of Netherlands, the Minister of Economic Affairs and Climate Policy. After closure, all legal responsibilities for the site, including monitoring and corrective measures can be transferred to the competent authority after a period of 20 years. However, this is only possible in case the authority is convinced the CO_2 is stored safely and a financial contribution by the operator has been made (article 18). This includes a financial contribution for monitoring efforts for at least 30 years, which contribution lies between 1 and 10 million euros. Operators are therefore at least for a period of 50 years responsible for monitoring. After this period, the responsibility is taken over by governmental authorities. Under Dutch rules, this period can however be shorter or longer depending on the judgment of the minister whether the CO_2 is completely and permanently sealed. No further additional conditions with respect to the judgment have been provided, leaving the length of the period uncertain. The minister can moreover recover any costs resulting from a leakage from the permit holder beyond the 20 years in case the operators has not acted carefully (article 31k under 5).

Analysis and Conclusion

Broadly, the current legal framework offers clear roles, tasks and responsibilities. This framework makes it possible to obtain a license for a CCS project, but at the same time leads to a number of uncertainties. Firstly, the storage site permit procedure is a competitive one; there is no guarantee of 'first come, first serve'. If another project developer applies for a permit on the same location, the minister choses between the applicants. This of course stimulates the selection of the best possible project emerges, but for project developers, it creates uncertainty. After all, they must to do the exploratory work, which can already be costly, without any certainty that they will be able to develop the project further.

Secondly, the costs of liability, beyond the EU ETS rights, as well as the costs of monitoring are not clear beforehand. There are a number of exceptions the minister can make to shorten or prolong the period of costs for the operator. Thirdly, any third party seeking access to the existing transport infrastructure comes across a lack of rules, even though the EU mandates member states to create such rules. In order to ensure CCS implementation, the legislator could seek to remedy these uncertainties by removing them as much as possible, while still fostering safety and affordability of the technique. Financial policy instruments can also contribute to this.

Financial Policy Instruments to Enable and Stimulate CCS

In addition to creating the appropriate legal frameworks, the government can also play an active role in stimulating mitigation techniques by providing for financial incentives. These could include subsidies and taxes that render the GHG emissions less attractive, i.e. more expensive, than the implementation of the reduction techniques. Below we will discuss the available financial instruments in place in the EU and Netherlands: The EU Emissions Trading System and Dutch SDE++ subsidy and carbon tax for industrial emissions.

EU Emissions Trading System

The EU ETS covers 45% of all CO_2 emissions in the EU (Directive 2009/29/EC, 2009; Regulation (EU) 2018/842, 2018). It provides a two-fold solution for the reduction of CO_2: (1) it lowers the cap on emissions each year by 1.7% (until 2020) and 2.2% (by 2030, although this will be higher depending on whether the EU Climate Law will be adopted) and (2) it puts a price on the remaining emission allowances. The remaining 55% of all CO_2 emissions is covered by the effort sharing scheme (Decision No 406/2009/EC, 2009; Regulation (EU) 2018/842, 2018).

Under the EU ETS, emitters hold emissions permits (article 4, 2009/29/EC) based on which emissions allowances are awarded. Subsequently, these permit holders are obliged to take emissions reduction measures, amongst which CCS counts (Haan-Kamminga et al., 2010). With increasing prices for emissions allowances, reduction, including by means of CCS, becomes more attractive. In order to be able to claim this reduction, there needs to be a direct relationship between the emitter and the entity responsible for the permanent storage of the CO_2. This is possible, as the permit holder may consist of a group of entities. However, this de facto requires all entities to be known at the time of application for a permit. This could be prevented by transferring the ownership of CO_2, which is possible under the Dutch Civil Code (article 7:1-48).

The price for emissions allowances is volatile, for instance, in 2018 a sharp increase in the price was detected (Verbruggen et al., 2019). In order to prevent volatility and steep differences, the EU devised the Market Stability Reserve. Allowances are inserted into the reserve in times of surpluses, and released back into the market in case of shortages. In this way, steep increases in prices can be prevented by increasing the offer of allowances.

SDE++ Subsidy for CCS

The scope of the Dutch SDE++ subsidy (from Dutch *Stimuleren Duurzame Energie*, Stimulating Sustainable Energy) was broadened in 2020 from solely renewable energy techniques to including emission reduction techniques like CCS as well. Before this date, there were no national subsidies available for CCS.

As a result of negotiations between environmental NGOs and energy intensive industries (EII), subsidy for CCS under the Dutch Klimaatakkoord, subsidy for CCS is capped at a reduction of 7.2 Mt CO_2, out of the annual industry reduction target of 14.3 Mt (Klimaatakkoord, 2019). This was done in order to keep societal costs low and to stimulate industrial parties to find other sustainable solutions such as large-scale electrification and green hydrogen.

The SDE++ subsidy is collected by means of a surcharge on energy consumption (ODE, from Dutch Opslag Duurzame Energie), of all types of energy consumers, albeit with different contributions. Households and small and medium enterprises contribute 1/3rd of the costs, whereas larger businesses contribute 2/3rd of the costs. However, the ODE tariffs are largely regressive, and decrease with increasing energy consumption (**Table 1**):

SDE++ subsidy is available only for the gap between the costs of the installation and the potential financial business case. The subsidy is given as a top-up on market prices, such that price risks are eliminated, but applicants compete for the subsidy, ensuring that the necessary subsidy decreases. Once CO_2 can be reduced by means of CCS, companies enjoy a potential advantage since less EU-ETS rights are required. This gain, however, will be siphoned off by lowering the CCS SDE++ subsidy.

For CCS, the maximum subsidy is fixed per ton of reduced CO_2, which can be rewarded for a period of maximum 15 years. Projects with an application for a lower subsidy than the fixed maximum are more likely to be rewarded. The total amount of SDE++ subsidies available in 2020 was € 5 billion. Of this, existing plants could receive up to € 39 per avoided ton of CO_2, and new capture installations (to be installed) for new plants up to € 76 per avoided ton of CO_2. New capture installations within existing plants can receive up to € 85 per avoided ton of CO_2. The 2020 SDE++ round ended in December, 2020. A total amount of € 6.4 billion has been applied for, through 4112 applications. Of this, € 2.1 billion within 7 projects have applied for CCS subsidy specifically. Since more subsidy has been requested than available, the Minister of Economic Affairs and Climate Policy will likely reward the cheapest reduction options, among which CCS is a contender. The final decisions are expected in the spring of 2021.

Carbon Tax for Electricity Production and Industrial Pollution

Whereas the EU ETS puts a price on carbon emissions, many studies have indicated the potential prices of emissions allowances are too low for deep emissions reductions (DER) techniques (Tvinnereim and Mehling, 2018; Söderholm et al., 2019). Combined with the volatile prices, this does not create a stable investment trajectory. Both at the Dutch and European level, within its Green Deal, it has been proposed to introduce a carbon tax to supplement the ETS price (Klimaatakkoord, 2019). The Dutch carbon tax will start at 30 EUR per ton CO_2 in 2021, increasing by € 10,56 each calendar year, leading to a CO_2 tax of € 125 per ton CO_2. Companies can deduct the costs of the EU ETS rights from this tax. This Act was accepted by Parliament

TABLE 1 | Overview of ODE tariffs.

Electricity	**0 – 10,000 kWh**	**10,001 – 50,000 kWh**	**50,001 – 10 million kWh**	**> 10 million kWh non-business related**	**>10 million kWh business related**
	€ 0.0300	€ 0.0411	€ 0.0225	€ 0.0004	€ 0.0004
Natural gas	**0 – 170.000 m^3**	**170,001 – 1 million m^3**	**>1 – 10 million m^3**	**> 10 million m^3**	
	€ 0.0851	€ 0.0235	€ 0.0232	€ 0.0232	

in November 2020. In December 2020, the Dutch Senate also adopted the proposal, ensuring its implementation.

Analysis and Conclusion

Since the implementation of the EU ETS, producers of CO2 have steadily reduced their emissions, with a reduction of 20% achieved at the EU level in 2020, relative to 1990. Combined with the increasing price of ETS rights, this instrument has been and can be further effective in reducing CO_2 emissions within the EU, for instance by means of CCS. The current legal framework in Netherlands ensures that permits can be obtained for CCS projects.

Recently, two important financial policy instruments have been introduced to further stimulate CCS. Their importance can be understood by remembering that the legal framework was already in place when the ROAD project was being undertaken, with the lack of appropriate financial instruments being the decisive factor in its abandonment. Since Porthos can contribute substantially to industrial emissions reductions, and parties, including EII and environmental organizations, have agreed that CCS is vital, the Dutch government has widened the scope of the SDE++ subsidy to include CCS, albeit with some restrictions: a cap of 7.2 Mt per year, a subsidy for maximum 15 years and a maximum tariff per avoided ton of CO_2. Combined with the introduction of the industrial carbon tax, which is likely to follow soon, reduction techniques are thus financially stimulated. Yet, of course, an important share of the costs will fall onto the Dutch EII. As the aim is to leverage public support and mobilize private investment in CCS, it is important to assess possible scenarios for company investments.

INVESTMENT UNCERTAINTIES OF CCS

It is abundantly clear that the costs of CCS are still a significant obstacle towards its large scale implementation (Budinis et al., 2018). The Global CCS Institute has provided an overview of the two most important cost components of CCS: investment and operational costs (Irlam, 2017). Investment costs relate to the initial investment in the capture plant, both for the design of the particular industrial process and for the installation of the plant. These are estimated to be between 20 and 110 € per ton of CO_2 capture capacity over a range of industries (Budinis et al., 2018). Operational costs fall into three categories: fixed and variable operational and management costs and energy prices. The fixed operational costs are typically estimated at 5% of all investment costs and include salaries, administration and overhead costs (Kuramochi et al., 2012; Yao et al., 2019) but importantly do not include interest and financing costs for the initial investments. Variable costs include the costs of labor, energy and inputs, especially in the capture process and are estimated to be around 60-80 €/ton of captured, transport ready CO_2 (Budinis et al., 2018; Gardarsdottir et al., 2019). Operational costs also extend to the operation of the transportation infrastructure; transportation, injection, storage and monitoring. Adding all this up (to 80–90 €/ton), it is abundantly clear that at current CO_2 prices of about 25€/ton, there currently is no profitable business case for CCS. At this price, even the variable costs cannot be recovered, let alone the fixed costs and a reasonable return on the initial investment. Low CO_2 prices played no significant role in the decision to abandon the Barendrecht project but were a decisive factor in the ROAD-project.

Of course, CO_2 prices are expected to rise in the future as deep cuts in CO_2 emissions necessarily call on a wide range of technical options, many of them more expensive than CCS (Wijnia and Croon, 2018). Also, as CCS becomes more common, early adopters may be better positioned to supply others with CCS technology and consulting, creating new markets and business models. One might argue that these are reasons for companies to start investing in CCS projects even if the business cases for their first projects are negative. It is intuitive that prospects for growth would improve the business case for CCS, but it is challenging to quantify such prospects and assess whether they are sufficient to make the case for CCS "Different this Time". In what follows we present an economic analysis of a CCS project that will give us a sense for the driving factors in the business case for CCS.

The Private Business Case for CCS – An Example

Consider the case of a steel company that invests in a carbon capture project worth 250 million €. This includes the cost of capture, onshore transport, and compression equipment. Assuming a construction period of 1 year, the project can capture 1 Mt CO_2/year for 30 years at a cost of € 70 million/year (including a "handling fee" of 2 €/t CO_2 to transport and store CO_2). In the process industry, the total operations and maintenance (OM) cost is typically 5% of capital expenditures. For simplicity we assume that the pre-investment spending is fixed and risk-free and the discount rate is set at 5%. The benefits for the project are the costs of CO_2 emission allowances that would have to be bought without CCS. This benefit is the quantity captured times the price of CO_2 emission rights. As our baseline we assume the historical trend of CO_2 prices with an annual average growth rate of 7% and volatility of 50% from the current

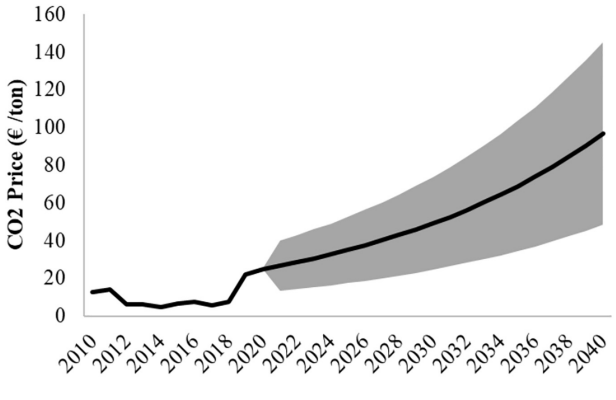

FIGURE 2 | Projected Prices of CO_2.

25 €/tCO_2 (see **Figure 2**). The avoided CO_2 is 1Mt/y. We set the decision horizon for the firm, admittedly arbitrarily, to 20 years. The key parameters for the computations are listed in **Table 2**.

The net present value for this project is negative (–132 M€, for full computation see **Supplementary Appendix 1**). At the average 7% growth rate in CO2 prices the price would cover marginal costs only in 2036 and at a 5% discount rate the profits in remaining years are insufficient to recuperate the capital costs[1]. It also means that the company should not invest in CCS until the CO_2 price covers the costs (the value of the project is zero if we start at 31 €/tCO_2 and project the 7% increase to a maximum of 200€ per ton for 30 years. See **Supplementary Appendix 1**). In order to appreciate the opportunity that CCS presents in mitigating future CO_2 pricing or other regulation, it is useful to consider the investment not merely on the basis of its expected net present value, but consider it as a 'real option'. Having the *opportunity* but not the *obligation* to invest in this project, is like having an option on buying an asset that yields a benefit equal to the uncertain CO_2-price times from the 1 Mt of avoided emissions minus marginal costs for the 30 year project duration.

Although the project is not interesting at today's prices and historical trend growth, the possibility that it will become profitable in the future makes the option to invest in this project valuable. Investing in the project when CO_2 prices hit the break-even level, however, would not be rational. The project would then yield a very low profit, while the firm could gain a lot by waiting to see where prices actually move.

This "real option" can be valued like a financial call option using the famous Black and Scholes formula and turns out to be worth 95 M€ (see **Supplementary Appendix 1**). Under current prices the early adoption of CCS technology is not optimal, and firms will wait *because* CO_2 prices are uncertain and expected to increase over time (Abadie and Chamorro, 2008; Heydari et al., 2010; Knoope et al., 2015).

[1]Note we assume that the firm only operates when the benefits exceed the marginal operational costs.

Investing Now to Benefit Later

We can also consider a further extension, in which we consider the investment in a pilot CCS project as creating the opportunity to pursue valuable follow-up projects if market conditions turn out favorably. With Netherlands' target of reducing carbon emissions by 49% by 2030, CCS could lead towards that goal by taking a share of up to 20 Mt CO_2 annual emission reductions by 2030 (Hellemans, 2018). If this is to be achieved (in Netherlands and elsewhere), a market for CCS expertise and experience must emerge. Investing in CCS now may give firms a head start in these future markets. As the market for CCS grows, innovation, economies of scale and learning-by-doing reduce CCS technology cost over time. We capture both market growth and technology learning by again considering our steel firm investing in a pilot CCS project with the parameters as described in step 1. However, we now assume the project positions the firm to benefit at a later stage, for which we assume a larger market size for CCS. In that phase, the firm has the option of selling its technology or providing consultancy and CCS services to other firms entering the market later. The key parameters for the computations are listed in **Table 3**.

If our firm invests in the pilot CCS project with a value of –132 M€ in the first phase, the estimated value of selling the "know-how" given the uncertainty in the market size on the second phase in our model is only 82 M€ (see **Supplementary Appendix 1**). As the firm can only profit from the emerging market for CCS technology after exercising the pilot project in the first stage, the value of those profits should be greater than the negative value of the pilot plant. The result therefore implies that the firm should not investment in CCS as an investment in know-how. In other words, the expected additional gains from the commercialization phase are not large enough to recover the losses from the pilot project. Along with the uncertainties in CO_2 prices and in social and political pressures discussed in previous cases, we show in step 3 that investment decisions for CCS will be low due to the uncertainty in technological learning and the uncertain evolving market size for CCS. Here, our model reveals that policy is necessary to attain a certain level of maturity for this technology. CCS needs frontrunners who are willing to take the risk in starting CCS investment projects and the pioneers might

TABLE 2 | Parameters of net present value and option valuation model in step 1.

Symbol	Variable	Value	Source
I	CAPEX	250 M €	Roussanaly, 2019
VC	Variable Costs	57.5 M€tCO_2	Roussanaly, 2019
FC	Fixed Cost	12.5 M€/year	
C	Capacity	1 MtCO_2/year	Value assigned for the valuation
T	Lifetime	30 year	Morfeldt et al., 2015
r	Discount Rate	5%	Knoope et al., 2015; Yao et al., 2019
P_0	Initial CO_2 price	25€/tCO_2	Gerlagh et al., 2020
α	Trend	7%	Calculated from Gerlagh et al., 2020
σ^2	Volatility	50%	Calculated from Gerlagh et al., 2020

TABLE 3 | Additional parameters for option valuation in step 2.

Symbol	Variable	Value	Source
NPV	Net present value of CCS	–132 M €	See assumptions in Step 1
Ms	CCS market size	20 MtCO2/year	Hellemans, 2018
Cf	Consultancy cost	4.5% of CAPEX	DECARBit, 2007
Lr	Technology learning	–17% change in CAPEX	Irlam, 2017
r	Discount rate	5%	Knoope et al., 2015; Yao et al., 2019
C	Capacity	1 MtCO_2/year	Value assigned for the valuation
t	Commercialization phase	10 years	Value assigned for the CCS commercialization phase

accept some of the losses from the pilot CCS projects to build a competitive advantage in the long run. Successful business cases for CCS will then generate more opportunities to continue the cycle creating a good market and more mature technology.

Our model extension shows that larger projected future markets will promote more CCS investments. Notably, the impact of more uncertainty in CO_2 prices now works positively on the business case. The intuition is that higher uncertainty in CO_2 prices now increases the upside (prices may move favorably, increasing demand in CCS markets), while it does not affect the downside (if the market is small the firm will decide not to enter it and losses can never be more that the -132 M€ of the pilot). However, in our calculation, the business case is still not positive and the government still has a role to play in closing the gaps that exists.

A Firm Social and Political Commitment to Ambitious Climate Mitigation Policies

We can extend our case by considering the possibility that the government imposes CCS as a condition for continuing operations at some unknown time in the future. We assume our industrial firm invests in CCS before that time in order to be able to continue operations when the policy is implemented. If the firm has an operational income of 3000 M€ per year, not investing in CCS in time puts that entire operational income at risk. The key parameters for the additional computations are listed in **Table 4**.

If the firm invests in CCS, the discounted income for 30 years of operation decreases from 48423 M€ to 48291 M€ (see **Supplementary Appendix 1**). Not investing in CCS, however, implies the firm risks having to shut down altogether. If we assume the probability of such a policy being implemented is 5% per year. This implies the probability that it happens within 10 years is 40% and within 20 years 64% and that risk reduces the value of the firm to 22020 M€ (see **Supplementary Appendix 1**). This is under the assumption that the firm has to stop operations altogether if it has not invested when the policy is implemented.

If we assume that a 1 year of revenue is lost to install the CCS capture technology once the policy is implemented, the firm would lose 1420 M€ (see **Supplementary Appendix 1**). Clearly such a loss justifies investing in CCS. The results imply that the government obligation improves the case for investing in a CCS project. We can show in step 2 that the value of CCS thus depends crucially on the uncertainty over the timing and intensity of social and political pressures to reduce emissions.

TABLE 4 | Additional parameters for option valuation in step 3.

Symbol	Variable	Value	Note
NPV	Net present value	–132 M €	See assumptions in Case 1
Pr	Probability	5%/year	Probability that the policy will be implemented
S	Annual operational income	3000 M € /year	Value assigned for the calculation

From the valuation result, our model predicts that more CCS projects will be viable in Netherlands when the government firmly commits to CCS, or firms see rising social pressures that may lead to a legal requirement for CCS to continue operations sometime in the future. As a corollary, in the absence of such commitment, incentives are weak. It should also be noted that the government must first secure a more stable CO_2 price and provide predictable and secure tax incentives and subsidies. Otherwise, companies will suffer serious economic losses and may choose to avoid these altogether by leaving the country or the industry, effectively eliminating the benefits for the climate.

Analysis and Conclusion

Starting from a stand-alone CCS project that is only based on the market price of CO_2, our model shows that private investment in CCS is unlikely to emerge. Also, CCS is not a convincing business case for frontrunners seeking to benefit from their "know-how" in future markets for CCS. However, adding the possibility of a government policy that imposes CCS as a precondition for continued operations, creates strong financial incentives to invest. Our analysis also shows that the rational waiting period to invest in CCS can be reduced by implementing policies requiring firms to operate with CCS, creating a more predictable trend in or increasing CO_2 prices, and by promoting future CCS markets to create incentives for technology learning from investing earlier. Implementing a CO_2 tax on top of the EU-ETS to create a predictable long run outlook on CO_2 prices, is therefore a crucial step. With that tax, things may turn out to "be different this time". A firm commitment to require CCS combined with (carbon tax financed?) subsidies to would allow firms to absorb the losses involved and seems to be needed to get private investment in CCS in Netherlands off the ground.

SOCIETAL ACCEPTANCE OF CCS

Although hard to quantify like cost-benefit and real option valuation models, societal acceptance, or the lack thereof, has proven to be a decisive factor in the implementation of CCS, as illustrated by two Dutch cases above (Brunsting et al., 2011; Kuijper, 2011; Terwel and Daamen, 2012; van Os et al., 2014; van Egmond and Hekkert, 2015; Jones et al., 2017). The role of societal acceptance is therefore a central focus point for academics, policy makers and potential investors.

The academic literature has focused on public acceptance of CCS as a climate change mitigation technique (van Alphen et al., 2007; Terwel and Daamen, 2012; Selma et al., 2014), acceptance at the project level (Brunsting et al., 2011; Kuijper, 2011; Terwel and Daamen, 2012; van Os et al., 2014; van Egmond and Hekkert, 2015), some focusing on specific countries (Fischedick et al., 2009; Toikka et al., 2014; Gough et al., 2018). Arning et al. (2019) found that CCU is more positively perceived than CCS by the public in Germany. Huijts et al. (2012) have developed a technology acceptance framework on the basis of psychological factors, which has been adopted by Selma et al. (2014) specifically for acceptance of CCS. From this, 13 concepts and corresponding definitions can be derived (**Table 5**).

TABLE 5 | Overview of CCS technology acceptance framework.

Concept	Definition
Personal factors	
Knowledge	Awareness of CCS, self-assessed knowledge and objectively assessed knowledge
Experience	Direct experience with CCS, but also with related technologies (e.g., fossil fuel extraction, underground gas storage)
Outcome efficacy	Belief that one own behavior affects the implementation of CCS
Role of CCS as climate mitigation technique and alternatives	
Problem perception	Awareness of climate change and consequences if no new technologies are implemented
Energy context	Relates to the current energy mix and the possible alternatives to CCS
Perceived benefits	All potential benefits attributed to CCS: for oneself, society and the environment
Affect	Feelings towards CCS, with positive and negative affect being two distinct dimensions
Factors relating to (organization of) projects	
Trust	Trust in stakeholders. In the case of CCS typically project developers, government, NGOs
Fairness, which includes:	Two types: Procedural fairness, such as fairness of decision processes and distributive fairness, including distribution of costs, risks, benefits
Perceived costs	Financial costs for individuals and society, and psychological costs (e.g., effort)
Perceived risks, including:	Potential risks to the health and safety of both humans and nature
Interference with nature	Perception of interference with the environment for implementation or tampering with the subsurface. This is closely connected to perceived risks
These 12 factors combined may influence:	
Acceptance/attitude	Expressed acceptance ("I would accept CCS") and revealed acceptance, which is displayed by engagement in activities for or against CCS

These factors are also highly relevant for Netherlands. Below we will assess how each of these factors relate to the overall acceptance of CCS in Netherlands and how this knowledge can be or is currently used by Dutch policy makers and investors in taking up new CCS projects. To this end, we have adapted the table from Selma et al. (2014), to group factors relating to the view of individuals, pertaining to knowledge and experience (see 'personal factors'), the role of CCS as a climate mitigation technique and possible alternative solutions and factors relating to the organization of projects. We base our assessment on a state-of-the-art literature review of CCS projects in Netherlands. This includes 16 studies, published between 2007 and 2020, of which the vast majority (15) has been published between 2007 and 2014 (see Annex II for the overview). The fact that these articles are relatively older, reveals that little is known about the current opinion of the public on CCS in Netherlands, in its current form: offshore and only with industrial carbon sources.

Personal Factors Influencing the Acceptance of CCS

Generally, the knowledge and awareness of CCS as a potential climate change mitigation is high in Netherlands. In a 2013 study 84% of the respondents knew about CCS. This can be explained by the Barendrecht case, as this received much media attention around 2010 (Ashworth et al., 2013). This also means that parts of the Dutch have some experience with CCS, directly or through media attention (de Best-Waldhober et al., 2012). It is currently unknown whether people believe they can affect the implementation of CCS.

Role of CCS as Climate Mitigation Technique and Alternative Solutions

On a more general level, the Dutch public is aware of the problem of climate change, and what is necessary in order to mitigate its consequences as much as possible. In a 2020 study by Netherlands Institute of Social Research, it was found that 77% of the respondents are aware of climate change, and 49% of the respondents are concerned about this issue (SCP, 2020). There are no recent studies on attitude or acceptance of CCS in Netherlands. However, in 2018 a report on prospects of Porthos showed that the ROAD project did not receive much negative notice and it is therefore likely that a new offshore project will not give rise to strong negative attention (Warmenhoven et al., 2018). Whether this also holds true for other projects, such as Athos, or all projects combined, is to be seen. Because little is known about the publics and affect opinion on CCS, there is also little information about perceived benefits in light of climate change.

Societal support can also depend on the carbon source, i.e. where the carbon is captured and therefore whether acceptance depends on or is supported by technology preferences. Dütschke et al. (2016) found that carbon capture at biomass plants was perceived more positively than captured at CFPP, as was also shown by de Best-Waldhober et al. (2009). This point is also raised by Gemeynt in their 2018 report, in response to ROAD and the plan to capture carbon at the Dutch CFPP. Since ROAD, a political decision has been made to phase out all coal-generated electricity, by means of a prohibition to generate electricity with coal domestically (Wet verbod op kolen). The four remaining Dutch CFPP therefore can no longer use coal latest by 2030 (Akerboom et al., 2020). Owners can however rebuild their CFPP into biomass plants and continue to generate electricity beyond that date.

Other key stakeholders, such as NGOs, have scrutinized CCS as a mitigation technique, regardless of the carbon source. CCS, it is as argued by NGO's, concerns an end-of-the-pipe solution, with little added benefits to society. It can moreover maintain the status quo of the fossil fuel industry, simply allowing them to deal with their waste products but not with the original

processes producing this waste (Swennenhuis et al., 2020). To this end, some have argued in the past that CCS should not be implemented. In Netherlands this discussion is also present. However, the importance of CCS as mitigation technique is increasingly being recognized. When CCS was discussed during the negotiations of the Dutch Klimaatakkoord, it was therefore agreed upon to aim to implement CCS, but to cap potential governmental subsidies to 7.2 Mt annually, in order to prevent high societal costs (see section "Financial Policy Instruments to Enable and Stimulate CCS").

Factors Relating to the Organization of Projects

Acceptance of a new technology can also be related to specific projects, how they are organized, whether and how the public is consulted, whether the public trusts the key players involved and if there are perceived costs and risks connected to this project.

Fairness, both procedurally and distributionally, is essential for the acceptance of projects. Research into the case of Barendrecht revealed that the resistance did not solely arise from risk perceptions, but also from a lack of trust in the central government (the project commissioner) and Shell (the operator), and a perceived unfairness of the decision-making process and lack of citizen involvement therein. These three factors have also been identified by other studies as significant contributors to societal acceptance (Terwel et al., 2011; Terwel and Daamen, 2012; Xenias and Whitmarsh, 2018; Arning et al., 2019). It is found that a joint effort of government, industry and NGOs for communication improves public perception of CCS, especially when there is transparency and openness about the process and the results (Gross, 2007; ter Mors et al., 2009) as well as having the opportunity to provide input during a decision-making process (Terwel et al., 2010). This could also increase trust in stakeholders, companies and government when implementing CCS. Therefore, new studies aim to develop strategies to introduce social acceptance into the design of CCS supply chains (Federico et al., 2020), in order to integrate this aspect early into the decision-making process.

The *perception of costs*, which is also closely related to the question of whether there are suitable and cost-effective alternatives to CCS, can be captured in willingness to pay for the technique. Increased costs of the energy system may have a negative impact on the perception of CCS (Shackley et al., 2009). Studies in countries like Germany have shown the amount or percentage of increased energy bills people were willing to pay if it led to the successful implementation of CCS (Kraeusel and Möst, 2012). A comparable study for the Dutch context has not yet been performed. Yet, the ODE tariffs, as paid for by small and large end-users towards the SDE++ subsidy are organized in such a way that only the business contribution is employed for the CCS subsidy. The contribution of smaller end-users is put towards renewable energy techniques. This ensures that households do not contribute towards reduction obligations of industry and larger businesses, in order to foster societal acceptance.

The *perception of risks* is evidently important for the support of CCS projects. CCS projects cannot guarantee that a leakage will never occur. Given the close vicinity of Barendrecht to the CCS project, many people felt unsafe (Brunsting et al., 2011; Kuijper, 2011; Upham and Roberts, 2011; Terwel and Daamen, 2012; van Os et al., 2014; van Egmond and Hekkert, 2015). Previous studies have showed that people feel more comfortable when a CCS project is further away from where they live due to safety concerns (Miller et al., 2007, 2008; Midden and Huijts, 2009; Chen et al., 2015). The experiences with onshore CCS projects have led to the decision to move CCS offshore (Swennenhuis et al., 2020), and a first attempt was made with the ROAD project, but this project failed due to a lack of business case, caused by low carbon prices (Read et al., 2019).

Analysis and Conclusion

From this survey of the state of affairs with respect to societal acceptance, we conclude acceptance of CCS is tacit rather than explicit. There is the expectation that offshore CCS will receive little negative attention. This appears justified by the lack of attention to and public interest for ROAD, but – beyond that (Warmenhoven et al., 2018)– it is not supported by empirical evidence. This means that there is no indication of whether Porthos will receive negative attention, or Athos, or all the CCS projects combined. This is a step forward compared to the earlier explicit rejection of onshore storage as well as of electricity production as carbon source.

There is little empirical evidence for large-scale implementation of CCS in a country context, but rather there is evidence for general attitude towards CCS or specific CCS projects, which in the Dutch context has aged already. A lot of key elements in building public support, however, are missing and/or lack empirical data. This is therefore an important knowledge gap in Netherlands, and more research into different scenarios (onshore/offshore, small-scale/large-scale) of CCS deployment is necessary in order to get a clearer understanding of the public acceptance of CCS developing beyond individual projects to an 'industry' and a portfolio of projects.

ANALYSIS – DIFFERENT THIS TIME?

In this paper we have analyzed the case of CCS for Netherlands. We surveyed the history of CCS in Netherlands and reviewed the reasons why a number of CCS projects were canceled. We then considered aspects of CCS feasibility – technical, legal, economic and societal – to bring us to a final analysis of the lead question: Different this time?

It has long been clear that carbon capture and storage offers significant potential to reduce emissions on a short to medium time scale, in particular in the cement, steel and petrochemical industry, in thermal power generation and in waste-to-energy facilities (Global CCS Institute, 2019). Technically, CCS is a straightforward proposition: CO_2 separation from gasses, including from flue gasses, is a mature technology (Vosbeek and Warmenhoven, 2007); CO_2 transport through pipelines and its injection in the subsurface is proven.

However, the notion that it is better to store CO_2 in the underground than to vent it into the atmosphere, obvious as

it may seem to some, is not uncontested. CCS however has faced several challenges towards implementation in the past, societal resistance led to the cancelation of two projects and the ROAD project failed due to a lack of business case. Since these projects, developments have led to changes: the carbon source will be restricted to industrial emissions alone, there are new financial instruments to stimulate CCS and there will be no more onshore CCS projects. In that sense, some factors influencing the successful implementation of CCS are indeed different this time.

Yet, some other issues persist: large uncertainties with respect to the business case, despite the introduction of the financial instruments, remain and may impact or effectiveness on the business case for CCS projects. Section "Governmental Support for CCS" highlights that elements of a fit-for-purpose legal frameworks are still lacking and that there are no binding targets for industry CCS, necessitating the use of CCS over other mitigating techniques. In that sense, not all factors are different this time.

One the biggest unknown factors at this stage concerns the societal attitude towards CCS under these, partly new, conditions. Conclusion of research in the past have aged, especially in light of the new conditions. It appears that there is no active resistance towards offshore CCS, yet we would like to point out that this is not the same as active support and the potential effects of the societal attitude are largely unknown.

Perhaps a better question for future research concerns the following: "How much CCS, and for how long?", for which there is no technical answer. An answer must be provided in the form of a socio-technical narrative in which the full set of prospects for carbon abatement technologies and their development over time are put in the context of societal needs of energy, industry and economy.

Looking back at the history of CCS over the past decades we must conclude that there never was a socio-technical narrative that was sufficiently compelling to garner broad support, nor was the narrative sufficiently stable over time.

Apart from a shift from power sector to industrial emissions, the core narrative of CCS is unaltered. It remains a transition measure, deemed crucial in the short and medium term, now especially in view of the fact that industry has processes that cannot be electrified and decarbonized fuels will not be sufficiently available for a long time. Once again, the argument in favor of CCS is that its deployment offers the possibility of rapidly and massively reducing emissions, above and beyond what can be done through other means, notably electrification.

The question it raises is to what extent its deployment gives fossil fuels a new lease on life, thereby standing in the way of renewables deployment, or slowing it down, in other words, maintaining the status quo. All agree that this should not be so; but, those in favor of CCS say it will not do so and those against say it will. In so far as CCS is accepted, it is as a transition measure, but how large the role for CCS is in the transition and how long the transition will be is still a matter of debate.

Lastly, perhaps the two most significant difference between a decade ago and today is the following: There is far greater active support from the government for CCS, it being one of the most important means for Netherlands to deliver on its 2030 emissions target. It is one of the most important means for Netherlands to deliver on its 2030 emission target. Perhaps the state of affairs is best summed up by avoiding the word acceptance and saying that CCS appears to be tolerated but not embraced. Empirical evidence on what to expect is essentially absent: the journey to CCS deployment beyond single, isolated projects is one into a societal *terra incognita*.

AUTHOR CONTRIBUTIONS

SA and SW suggested the topic of the manuscript. SA wrote Sections "Governmental Support for CCS" and "Societal Acceptance of CCS," and co-wrote Sections "Introduction" and "A Brief History of CCS in Netherlands and Europe." SW co-wrote Section "A Brief History of CCS in Netherlands and Europe" and proof-read the article. AM wrote Section "Technology Options: CCS, CCU, and CC(U)S." CA and MS co-wrote Section "Investment Uncertainties of CCS." GK wrote Section "Analysis – Different This Time?" and co-wrote Section "Introduction," and provided guidance for the manuscript. All authors provided critical feedback on all sections.

SUPPLEMENTARY MATERIAL

The Supplementary Material for this article can be found online at: https://www.frontiersin.org/articles/10.3389/fenrg.2021.644796/full#supplementary-material

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Transport Cost for Carbon Removal Projects With Biomass and CO_2 Storage

Joshuah K. Stolaroff[1], Simon H. Pang[2], Wenqin Li[3], Whitney G. Kirkendall[4], Hannah M. Goldstein[1], Roger D. Aines[1] and Sarah E. Baker[2]*

[1] Atmospheric, Earth, and Energy Division, Lawrence Livermore National Laboratory, Livermore, CA, United States, [2] Materials Science Division, Lawrence Livermore National Laboratory, Livermore, CA, United States, [3] Computational Engineering Division, Lawrence Livermore National Laboratory, Livermore, CA, United States, [4] Global Security Computing Applications Division, Lawrence Livermore National Laboratory, Livermore, CA, United States

Strategies to remove carbon from the atmosphere are needed to meet global climate goals. Promising strategies include the conversion of waste biomass to hydrogen, methane, liquid fuels, or electricity coupled with CO_2 capture and storage (CCS). A key challenge for these projects is the need to connect geographically dispersed biomass supplies with geologic storage sites by either transporting biomass or CO_2. We assess the cost of transport for biomass conversion projects with CCS using publicly available cost data for trucking, rail, and CO_2 pipelines in the United States. We find that for large projects (order of 1 Mt/yr CO_2 or greater), CO_2 by pipeline is the lowest cost option. However, for projects that send most of the biomass carbon to storage, such as gasification to hydrogen or electricity production, biomass by rail is a competitive option. For smaller projects and lower fractions of carbon sent to storage, such as for pyrolysis to liquid fuels, CO_2 by rail is the lowest cost option. Assessing three plausible example projects in the United States, we estimate that total transport costs range from \$24/t-CO_2 stored for a gasification to hydrogen project traversing 670 km to \$36/t for a gasification to renewable natural gas project traversing 530 km. In general, if developers have flexibility in choosing transport mode and project type, biomass sources and storage sites can be connected across hundreds of kilometers for transport costs in the range of \$20-40/t-CO_2 stored. Truck and rail are often viable modes when pipelines cannot be constructed. Distances of 1,000 km or more can be connected in the same cost range when shared CO_2 pipelines are employed.

Keywords: CCS, negative emissions, BECCS, hydrogen, CO_2 transport, carbon dioxide removal (CDR), biofuels

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Imperial College London,
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Shuiping Yan,
Huazhong Agricultural University,
China
William Joe Sagues,
North Carolina State University,
United States

****Correspondence:***
Joshuah K. Stolaroff
stolaroff1@llnl.gov

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INTRODUCTION

It is now well understood that carbon removal strategies, also known as negative emissions technologies (NETs), will be needed to achieve a net-zero carbon society, and specifically to achieve climate goals of limited warming (Masson-Delmotte et al., 2018; National Academies of Sciences, Engineering, and Medicine, 2019). One long-studied type of carbon removal is the combustion of biomass coupled to carbon capture and storage (bio-energy with carbon capture and storage,

BECCS) (Minx et al., 2018). Traditionally, the biomass is combusted to produce electricity, which is sold as a co-product.

There have been a handful of BECCS projects so far (Consoli, 2019). Furthermore, biomass-fired power plants without carbon capture are common, and CCS has been demonstrated on fossil plants such that coupling the two is expected to be straightforward compared to many other NETs.

A related set of strategies, much less studied, is to convert biomass to other products, such as liquid fuel, renewable natural gas (methane), or hydrogen, while capturing and storing the process CO_2. If the source of biomass regrows and has limited other climate impacts, then the result is net-negative biofuels (NNBFs): clean fuels and carbon removal as co-products.

The source of biomass, type of fuel, and processing technology all affect the life cycle climate impact of biofuels. CCS can be added to traditional fermentation processes such as corn ethanol, but this rarely would result in net negative fuels because the amount of CO_2 stored is smaller than emissions associated with cultivating crops and other aspects of the life cycle (Rosenfeld et al., 2020). However, NNBFs can generally be achieved using waste biomass, such as agricultural residue or brush and small trees from fire management in forests (Creutzig et al., 2015). These feedstocks typically have a small greenhouse gas impact (Helena et al., 2011), which can be more than offset with CCS.

Recently, with our coworkers, we assessed many pathways for NNBFs and BECCS as well as other carbon removal strategies for the U.S. state of California (Baker et al., 2020). We found that NNBFs, and specifically biomass gasification to hydrogen, had the largest potential and among the lowest cost of carbon removal options for California. The high availability of waste biomass and excellent geologic conditions for CO_2 storage in the state contribute to this result, however, these circumstances are far from unique. The National Academies assessed biomass in the United States for energy applications and estimated 512 Mt/yr of wastes and residues were available (National Academies of Sciences, Engineering, and Medicine, 2019). The Department of Energy's Billion Ton Report estimates that biomass availability in the U.S. for various scenarios and price points is in range of 365—709 Mt/yr, not including energy crops. Each of these are similar on a per capita basis to the 55 Mt/yr that we estimated for California. Previous studies have found large areas of the United States have suitable geology for CO_2 storage, including biomass-rich regions in the upper Midwest and southeast (Baik et al., 2018).

In Baker et al. (2020) we found that NNBFs have enormous potential to contribute carbon removal at a reasonable cost while providing clean fuels and other benefits, such as jobs and waste disposal.

New incentives, specifically the 45Q tax credit in the United States and recent amendments to the Low Carbon Fuel Standard in California, are adding to interest in NNBFs. Multiple companies are actively pursuing or developing NNBF projects, including Clean Energy Systems, San Joaquin Renewables, and Charm Industrial (Charm Industrial, 2021; Clean Energy Systems, 2021; Cox, 2021). However, despite favorable economics, no NNBF projects using CCS yet exist in the United States, in part because of their inherent complexity; a successful NNBF project has to solve a transport and logistics problem that connects at least four elements:

1. The supply of biomass
2. The biomass conversion facility, e.g., gasification or pyrolysis plant
3. The CO_2 storage site
4. The customers of the fuel or electricity

The fourth element, transport of electricity or fuel from the plant to customers, is relatively well-understood and typically contributes a small share to the cost of those commodities. An exception to this may be for hydrogen, which currently doesn't have as wide a customer base or well-developed transport network as for methane or liquid fuels. Transport of hydrogen by truck is straightforward in the absence of other options, but the proximity of hydrogen users may constrain the placement of NNBF plants more than for other fuels. Overall, we don't consider the cost of fuel transport here and rather focus on the first three elements above.

Transport of biomass for bioenergy has long been considered an important cost driver. Compared to fossil fuels, biomass carries relatively less energy per unit mass, and so assessments of bioenergy potential have concluded that biomass transport distances must be relatively short for economic success (Helena et al., 2011). The calculation changes when biomass is considered as a carrier for carbon removal. Many forms of biomass are carbon-rich, making them feasible to transport for longer distances than when biomass is valued as an energy carrier alone. This is one effect assessed in the present work.

CO_2 transport costs have been previously assessed for fixed project locations (Onyebuchi et al., 2018) and in some cases for large networks (Psarras et al., 2017; Sanchez et al., 2018). However, there are specific dynamics for NNBF projects that haven't been previously explored, in particular that CO_2 transport and biomass transport can be traded off by selection of the project site. Further, rail has received relatively little attention compared to pipelines in the CO_2 capture and carbon removal literature, but should be considered for NNBF projects. We gave the latter two points consideration in Baker et al. (2020) but only in the context of an integrated transport network for a mature carbon removal system in California. A more general treatment has not yet been performed.

In this paper, we seek to estimate the cost of carbon transport for NNBF projects as a function of distance and type of project. For project developers, there will often be a choice about which mode of transport to use and whether to transport biomass or CO_2 the longer distance. We identify the circumstances that favor each of the choices. To do this, we first lay out our assumptions on the logistics of NNBF projects. We then report unit cost estimates for several modes of transport from the literature. Finally, we calculate transport costs per unit of CO_2 stored for an NNBF project as a function of several variables, including distances, plant size, and biomass conversion technology. We conclude with a discussion of implications of these findings for NNBF developers and for policymakers considering carbon removal incentives.

MATERIALS AND METHODS

In this paper, we aim to assess the costs of carbon transport for BECCS and NNBF projects in the United States. The analysis shares some common methods and assumptions with Chapter 7 of Baker et al. (2020) but here we generalize the results for the United States and set aside the system integration aspects, taking the perspective of a single project. The cost data below are sourced from the United States, but the general trends and relative costs between modes should be similar internationally.

As discussed in the previous section, a successful NNBF or BECCS project must connect at least three elements: biomass supply, plant, and CO_2 storage. There are a variety of transport strategies to achieve this. Biomass can be transported by truck or rail, and CO_2 can be transported by truck, rail, or pipeline. Both can also be transported by ship, but this option is highly limited by geography and we don't consider it here.

Major potential sources of waste biomass include forest residues, agricultural residues, municipal solid waste, as well as liquid wastes, such as from food processing, and biogas, such as from landfills and wastewater treatment. Liquid and gaseous wastes are available in relatively small volumes and have different challenges for use as NNBFs. We focus here on the major categories of solid biomass.

For solid biomass, the carbon chain typically starts with a collection stage by truck or off-road vehicle and ends with CO_2 injection at a geologic storage site. One major choice is whether to site the conversion facility near the biomass and transport CO_2 the greater distance, or to site the facility near the storage site and transport the biomass. There are several additional choices for the mode of transport in between. **Figure 1** illustrates five possible transport chains, which are named for the longest leg in each case. Each of these five scenarios is assessed for several example projects described below.

These scenarios assume that an NNBF facility is sited either near biomass sources or near CO_2 storage, and not at an intermediate distance between. For a single project, and considering transport costs alone, the economic optimum will always be one of these two extremes. However, with permit restrictions, limited rights-of-way, or other practical considerations, a developer may choose an intermediate plant location. In that case, the transport cost can be estimated by a weighted average of the two scenarios. Another case where intermediate siting is preferred is within a network of multiple plants, where CO_2 flows can be combined into a common trunk line. That scenario is beyond the scope of this paper, however, the transport cost prior to the shared trunk line (which is likely to be the larger cost) can be estimated by the methods below.

Biomass Collection

The first step in the carbon chain is collection and pre-treatment of biomass into loads suitable for transport by on-road truck. Representative costs for this stage are shown in **Table 1** along with average moisture content of the biomass, which affects transport costs down the line. Collection cost is not the focus of this analysis, be we discuss it here for context.

Collection of forest and chaparral residues typically includes chipping and potentially drying before loading trucks at the roadside. For agricultural residues, collection and processing may have already occurred, such as for pistachio shells or almond hulls. As a result, such residues can be purchased at very low additional cost. Other types require collection from the field, so collection cost varies widely. Municipal solid waste (MSW) is already collected by truck and typically already sorted. Biomass from MSW may even be available at negative cost because processing this waste avoids tipping fees at landfills. As described in the Billion-Ton Report (Langholtz et al., 2016), many millions of tons of biomass are available in each of these categories in the United States; any of these types of biomass could support an NNBF project. Supplies are sufficiently concentrated that even a large NNBF plant, say 1 Mt/yr biomass capacity, could, in many places, be supported by a single county supply, or in other cases by several adjacent counties.

Transport of Biomass

From the collection points, biomass will typically be trucked either to a rail station for longer-range transport, or directly to a biomass conversion facility. Trucking is a commodity market with stable prices. Average operating expenses of commercial trucks are surveyed annually by the American Transportation Research Institute (Hooper and Murray, 2018), who reported a national average of $1.05/km in 2017. The cost per ton depends on the load size and capacity factor. We assume that outbound trucks carry 22 tons of biomass, which is close to the legal limit and tracks the average net loads for trucks carrying bulk commodities (National Research Council, 2010). Although there are some agricultural residues that aren't dense enough to fit 22 t in a standard trailer volume, these can be compacted or otherwise processed to reduce shipping volume. We assume the trucks return empty (50% capacity factor). We also add 6% profit to reflect prices for the project operator (Biery, 2018). The resulting unit cost is shown in **Table 2**, along with several other unit costs described below.

Biomass transport by rail is also common in the U.S. as well as internationally. Rail is well known to have lower cost and lower externalities than trucking (GAO, 2011), so it is generally preferred wherever it is available. However, rail access is limited and building new rail spurs is expensive, with representative costs in the range of $0.6–1.2 M/km – somewhat more than for CO_2 pipelines (Compass Int., 2017). Short delivery distances may also favor trucking.

The market for rail transport is more heterogeneous than for trucking. Unit prices vary significantly contract to contract, and average prices vary by about a factor of two depending on the travel distance, load size (number of cars), and type of commodity (Prater and O'Neil, 2014; Mintz et al., 2015). For our base case cost, we assume that transport will be in the short-haul category (<800 km), but with larger loads (>75 cars per train), suggesting a unit cost that is 1.6 times the national average.

Transport of CO_2

Once biomass is transported to the NNBF or BECCS facility, it is processed and treated. The resulting CO_2 is captured and either

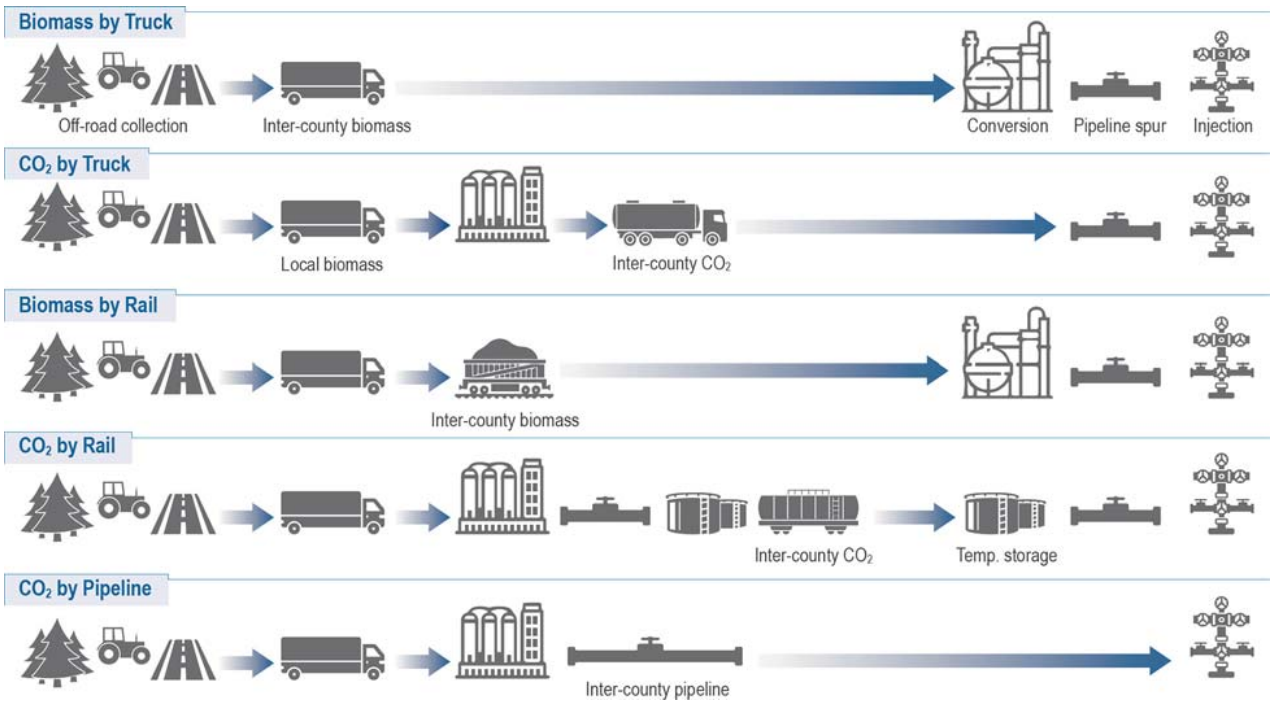

FIGURE 1 | Possible transport configurations for Net Negative Biofuels projects. Inter-county refers to the longer leg of the sequences, while local refers to transport of tens of kilometers.

TABLE 1 | Typical collection costs and water content for major categories of waste biomass.

	Representative collection cost ($/t dry basis)	Average moisture content (mass basis)
Sawmill residue	0 (already collected)	30% (Jones et al., 2013)
Forest fire management	50 (Baker et al., 2020)	30% (Jones et al., 2013)
Shrub and chaparral fire management	80 (Langholtz et al., 2016)	30% (Jones et al., 2013)
Agricultural residue	0–60 (Langholtz et al., 2016)	25% (Breunig et al., 2018)
Municipal solid waste	<0 (already collected; may pay disposal fee)	10% (Breunig et al., 2018)

compressed for transport via pipeline or liquified for transport by truck or rail. Pipeline CO_2 can then be injected directly underground when it reaches the storage site. Liquified CO_2, which is kept at about −40°C and 20 bar of pressure, must be warmed and compressed before injection into a pipeline (80–120 bar and ambient temperature).

Liquified CO_2 can be transported in insulated tanker cars that are similar between truck and rail. We assume the near-full capacity of 22 t is retained for trucks, however, costs are somewhat higher because the trailers are more expensive and the trucks are slightly more expensive to operate and maintain. Survey results give $1.16/km with the adjusted unit cost shown in **Table 2**.

TABLE 2 | Unit costs for truck and rail transport.

	Biomass transport cost	Cryogenic CO_2 transport cost
Truck	0.101 $/t-km	0.111 $/t-km
Rail	0.044 $/t-km	0.044 $/t-km + 2 $/t

CO_2 transport by rail is less common than other modes. Although it occurs commercially (ITJ, 2019), we have not found published market data on CO_2 specifically. The costs should be similar to other tanker-shipped commodities, with the exceptions that staging and loading facilities must be built at the origin station, and unloading and reconditioning facilities must be constructed at the destination station. A pipeline spur is likely also needed at the destination.

Two studies have used techno-economic models to estimate the cost of CO_2 by rail for CO_2 storage case studies. Gao et al. (2011) calculated 77 RMB/t-CO_2 ($13/t in 2018 US dollars) to transport 1.5 Mt/yr over 600 km for a project in China. This included $0.88/t for staging and loading facilities. Roussanaly et al. (2017) estimated 4 €/t and 11 €/t ($5 and $13) to transport CO_2 for 50 km and 200 km, respectively, for a project in the Czech Republic. That includes about 1 €/t for loading and unloading facilities. The staging operation thus appears to be a minor part of transport cost. Overall, we assume that the staging and loading operation adds 2 $/t-$CO_2$ to the cost of transport by rail, while the unit cost remains the same as for biomass.

The cost of CO_2 transport by pipeline is more variable than for other modes since it depends on local construction costs and securing rights of way. Even with these challenges, pipelines are strongly preferred for large volumes of CO_2. There are over 7,000 km of CO_2 pipelines in the U.S. as well as a vastly larger network of natural gas pipelines that also informs the cost of pipeline construction (Wallace et al., 2015).

To estimate CO_2 transport costs via pipeline, we use a spreadsheet-based model developed by the National Energy Technology Laboratory (NETL, 2018), which in turn implements several earlier models from the literature (Parker, 2004; McCoy and Rubin, 2008). When validating the model against recent CO_2 pipeline projects, the authors found that the variant based on Parker tended to overestimate costs, while the variant based on McCoy and Rubin underestimated it. We thus take these to be the upper and lower bounds of the pipeline costs in further analysis. **Figure 2** shows results from the model for a 1 Mt/yr CO_2 flow. The McCoy model provides costs for five different regions of the U.S. This yields a cost variation of about +/−20%, whereas the difference between the models can be more than a factor of two. For the generic cost comparisons in **Figures 5** and **6**, we use the lowest regional result from McCoy (central) and the Parker results as the lower and upper bounds, respectively. For the single-point cost estimates in **Figure 7**, we use the midpoint between the average of the McCoy estimates and the Parker estimate. The retrieved costs are the break-even cost of CO_2 transport in the first year of operation.

Plant Size and CO_2 Storage Factor

The amount of CO_2 that ultimately ends up in the ground for each ton of biomass collected depends on the BECCS or NNBF technology used, and to a lesser extent, on the type of biomass. To estimate the transport costs per ton of CO_2 stored, we have to account for this "CO_2 storage factor." **Table 3** shows these factors for a handful of likely projects. Most of these plant types are in development in California or neighboring states. The values range from 0.49 t CO_2 per t dry biomass for a pyrolysis to liquid fuels plant, where the majority of biomass carbon ends up in fuel, to 1.6 for gasification to hydrogen, where virtually all the input carbon ends up in the ground. For combustion to electricity, we assume the CO_2 capture system is 90% efficient, a typical benchmark, but it could be made more efficient. Alternatively, some gasification plant designs are less efficient at capturing CO_2 and would have slightly lower values. Project developers can make these choices based on market conditions and regulatory incentives for carbon removal. These storage factors, and thus the costs per ton of CO_2 calculated later, do not account for fossil CO_2 emitted during transport or other life-cycle considerations. However, we previously found transport-related emissions to be less than 1% of the CO_2 stored (Baker et al., 2020).

Along with the storage factor, the size of the BECCS or NNBF plant determines the flowrate of CO_2 and biomass that must be transported. This affects the cost of pipelines most strongly. In general, larger plants are more economic from a transport perspective. Although not covered here, CO_2 storage cost also depends strongly on CO_2 flowrate. A larger NNBF project may be able to support a dedicated storage project economically; for reference, a single well in a good formation can accept on the order of 1 Mt/yr of CO_2 injection. Smaller projects would likely need to send CO_2 to a storage site that aggregates CO_2 from multiple sources for the best marginal cost. Aggregating CO_2 sources would also be a way to economically transport CO_2 over longer distances by using a shared CO_2 trunk line.

Operating commercial pyrolysis plants are typically small, around a few hundred tons per day of dry biomass (Lee Enterprises Consulting, 2020), though a handful of recently proposed biomass projects without CCS are sized at 1,000 t/d of biomass, such as the Clearfuels gasification plant in Tennessee or the Rialto pyrolysis plant in California, (NETL, 2016). CO_2 capture, transport, and storage would be significantly more expensive at the smaller end of this spectrum. There isn't enough information on capture costs at small scale (most estimates focus on the much larger power plant scale) to confidently select an optimum size for NNBFs, but a study of CO_2 capture systems for industrial sources predicts steep increases in cost below 0.25 Mt/yr CO_2 for several source types (Herron et al., 2014). As we show below, pipeline transport costs increase sharply below about 0.5 Mt/yr. For these reasons, we find it unlikely that a developer would choose an NNBF project in the hundreds of tons per day size range. As another point of reference, coal gasification plants, a relatively mature technology, are frequently in the size range of 7,000–8,000 t/d coal, illustrating the economies of scale in gasification equipment (NETL, 2016). Altogether, we consider 2,000 t/d biomass as a reasonable reference size. This is the value used in the three case studies described below. This is also a common commercial plant size assumption to meet the cost goal for hydrocarbon fuels production from lignocellulosic biomass proposed by the U.S. Department of Energy (Jones et al., 2013; BETO, 2016).

To maximize the carbon removal potential of pyrolysis to liquid fuels, we assume CO_2 is captured from the off gas of non-condensable gas (NCG) combustion as well as off gas from steam reforming of aqueous phase bio-oil. The storage factor was calculated as 0.494 t CO_2 stored per dry ton biomass input based on a process carbon balance (Li et al., 2017). There is also storable biomass carbon in the biochar, which can be sequestered above ground as a soil amendment. How much of the biochar carbon is stored and for how long depends on the use of the biochar. As a soil amendment the majority of carbon is likely to remain sequestered for over 100 years. We have not included the stored carbon from biochar here, instead focusing on geologically stored CO_2. However, including a stored biochar component would tend to decrease the apparent transport costs per unit of CO_2 removed.

The storage factor for biomass combustion to electricity is derived from the mass balance reported in Jin et al. (2009). Since the modeled combustion facility uses air to combust the biomass, the flue gas contains a significant fraction of nitrogen that must be separated from the CO_2 prior to sequestration. In this case, the CO_2 in the flue gas is assumed to be captured via an amine system (Cansolv) at 90% efficiency (Zoelle et al., 2015). Other process configurations, such as oxy-combustion or indirect combustion of biomass, would result in CO_2-containing streams that could be captured by other technologies not considered here.

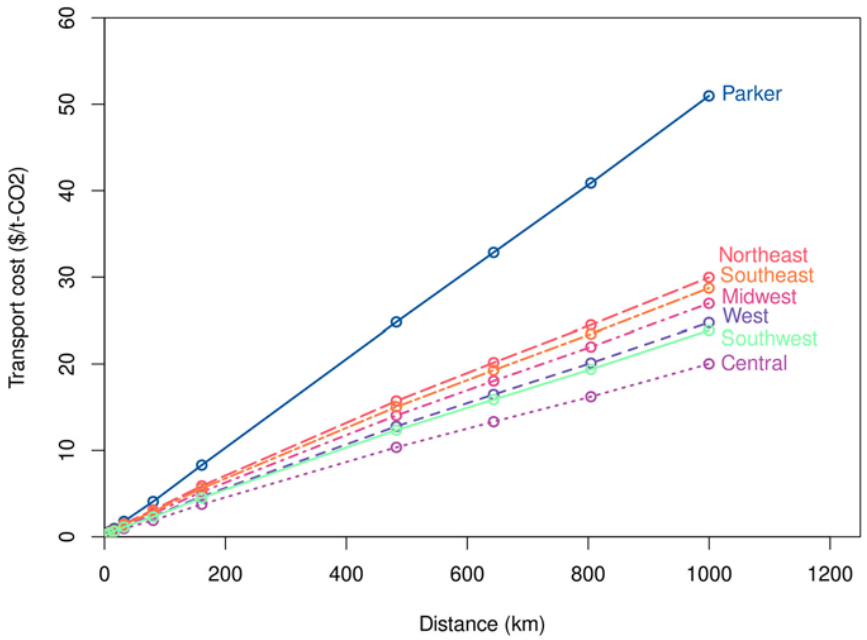

FIGURE 2 | Cost of CO_2 transport by pipeline in the United States by model and region for a flow of 1 Mt/yr in 2014 dollars. "Parker" represents the model with the Parker (2004) variant, and the other lines show results for the McCoy and Rubin (2008) variant for the respective regions of the U.S.

The storage factor for biomass gasification to hydrogen is derived from the mass balance reported in Larson et al. (2009). The water-gas shift process to produce hydrogen can be operated to convert nearly all of the carbon in the biomass feedstock ultimately into CO_2; the bulk of this CO_2 is removed from the hydrogen by a refrigerated methanol (Rectisol) process, and is high enough purity after drying for direct sequestration without adding additional capture units, due to the use of an oxygen-blown gasification process.

Finally, the storage factor for biomass gasification to renewable natural gas (RNG) is derived by estimating the fraction of CO_2 in the gas stream before methanation, based on the composition of the CO_2-containing syngas emitted from the gasifier units in Larson et al. (2009) By mass balance, the hydrogen-to-CO ratio in the syngas is adjusted via water-gas-shift to maximize the amount of methane produced, which increases the fraction of CO_2 in the gas stream. The CO_2 is removed prior to methanation by a refrigerated methanol process.

In principle, anaerobic digestion of biomass with CCS is an alternative pathway to net-negative RNG. However, existing anaerobic digestors, such as for manure and wastewater treatment, are small compared to thermochemical plants. This would lead to much higher CO_2 capture and transport costs. These costs could be mitigated with new capture technology and a CO_2 aggregation scheme across sources, but this is a more complex scenario and we don't consider it here.

Example Projects

To illustrate the transport cost calculation, we select three plausible project configurations from the United States as case studies. Their locations are illustrated in **Figure 3**. For the first example, we look to California, where Baker et al. (2020) compiled quantities of biomass waste and residues by county. We found some of the largest sources of biomass include the forested counties in the north, foremost Siskiyou County, for potential fire clearing and sawmill residue. Meanwhile, the nearest of the two most favorable geologic storage locations is in the Bay Delta region in the center of the state, especially in San Joaquin County. These areas are marked in **Figure 3A**. Since the source area is remote from population centers, product transport could be an challenge here. We choose gasification to renewable natural gas as the technology scenario because the RNG can be injected into existing pipelines in Siskiyou county if the plant is sited there.

For potential projects outside California, we are not aware of a similar multi-criteria screening for CO_2 storage sites on the national level, though some studies have characterized national storage potential in terms of broad geologic formation and found wide availability (NETL, 2015). CO_2 storage has also been demonstrated in a handful of projects, including two sites in the Gulf Coast region of the U.S. for the SECARB program, which has injected millions of tons of CO_2 for research and demonstration (Foshee, 2010). We use these two proven sites – Natchez, Mississippi (Adams County), and the Citronelle oil field in Mobile County, Alabama – as the CO_2 storage locations in two further scenarios.

The Billion Ton Report (Langholtz et al., 2016) provides biomass waste and residue availability in the United States at the county scale. We surveyed these data in the vicinity of the two storage locations to identify biomass sources large enough to support 2,000 t/d plants. For the second example project, we select municipal solid waste from the highly populated Houston area (Harris County) to be gasified to hydrogen with CO_2 stored

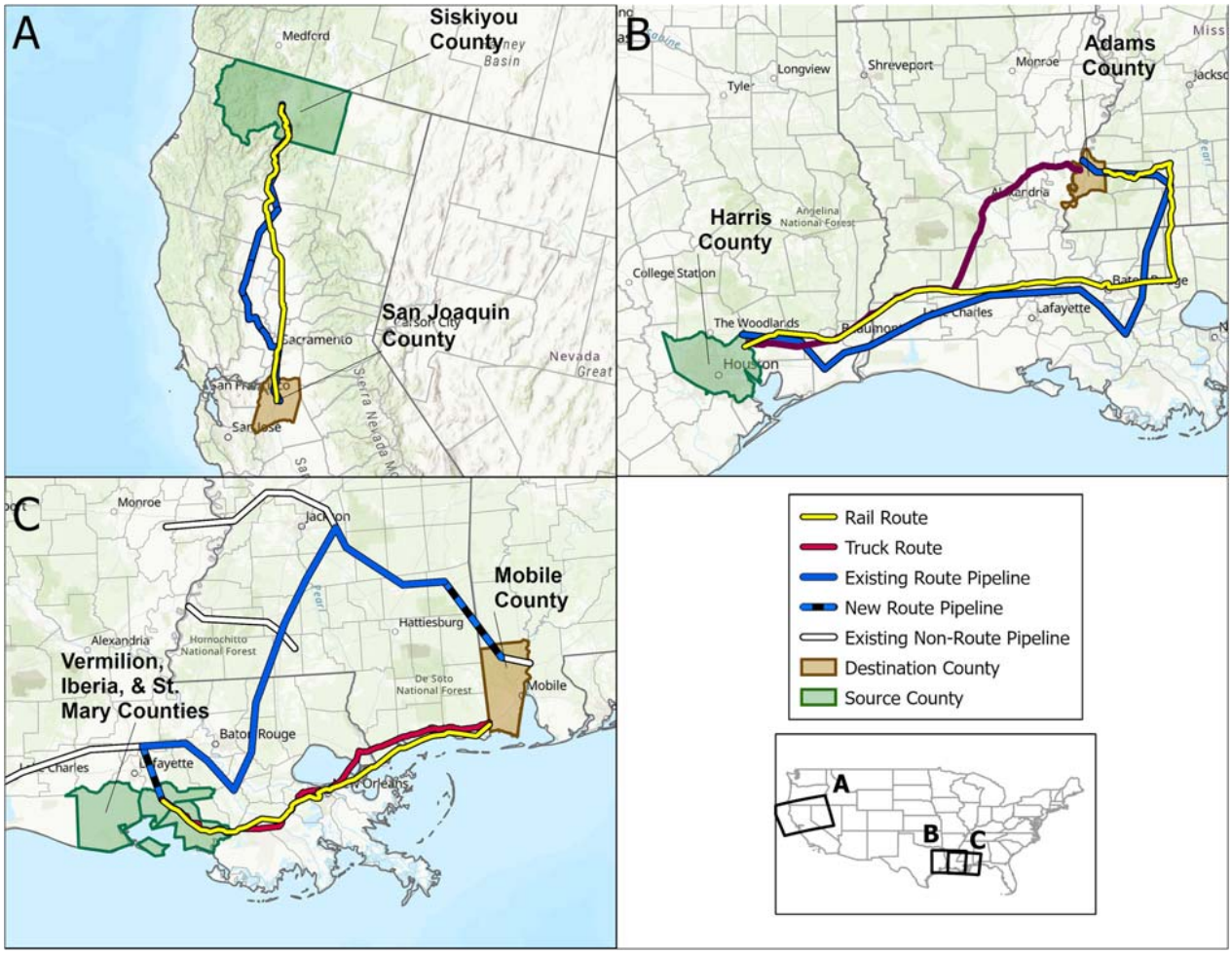

FIGURE 3 | Map of example NNBF project locations showing biomass source areas, CO_2 storage sites, and proposed rail and pipeline routes. **(A)** Route for forest biomass in Siskiyou County, CA. **(B)** Route for municipal solid waste from Harris County, TX (including Houston). **(C)** Route for agricultural residues from Iberia, St. Mary, and Vermilion Counties, LA.

in Adams County. The hydrogen can then be sold to one of the many chemical plants or refineries in the region. Incidentally, there is an existing CO_2 pipeline that connects the source and destination counties. If the pipeline could be shared with its current uses, this would undoubtably be the lowest cost transport option. However, for sake of generality, we merely use the pipeline route for distance and calculate costs as if a new pipeline is constructed for the project of the same length.

For the third case study, we select agricultural residue from the region south of Lafayette to be converted by pyrolysis to liquid fuel with the process CO_2 stored in Mobile County. The source counties are relatively small here, so we aggregate biomass from three counties to meet the plant's demand. For the rail and pipeline scenarios, transport costs are calculated as if the biomass is trucked to a common depot in Iberia County (the center of the three) where it is either processed or transferred to rail to be processed in Mobile County. Again, there is an existing CO_2 pipeline. In this case, it traverses most of the distance between the source and destination counties, but not completely. We add pipeline legs (shown as hatched segments in **Figure 3C**) to make the final connections. Again, we use the pipeline route only to measure distance and calculate transport cost as if a dedicated pipeline is constructed.

The transport distances for each mode and case study are calculated using ArcGIS following existing rail, road, and CO_2 pipeline networks. In the Siskiyou County case, a hypothetical CO_2 pipeline route was drawn to follow existing major natural gas pipelines (since there are no CO_2 pipelines in the region). For convenience, several of the routes were calculated to the nearest intersection with a county boundary rather than centroid. The difference is minor and is roughly compensated by our choice of destination spur length.

For each scenario, the average local trucking distance is based on the size of the biomass source area:

$$d_{local} = \frac{1}{2}\sqrt{A}$$

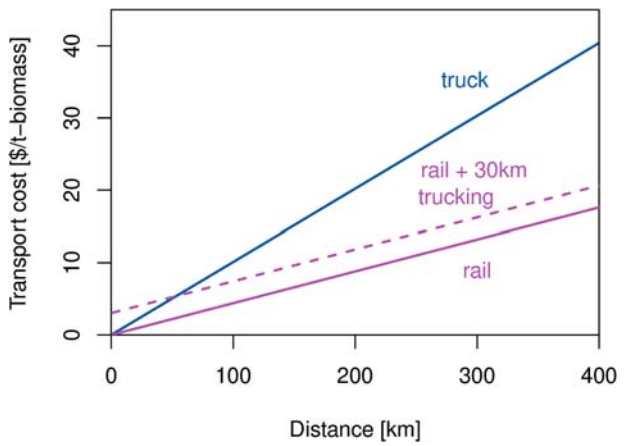

FIGURE 4 | Transport cost of biomass by truck and rail as a function of distance. The dashed line represents a scenario combining consolidation of collected biomass to a rail station via truck (average trip of 30 km) followed by transport by rail for the distance indicated.

where A is the area of the origin county or set of counties. This approximates the average distance between random points within the area (Talwalker, 2016). The distance from the storage site to a rail station is based roughly on the size of the storage county relative to the rail route shown. The CO_2 storage factors are taken from **Table 3**.

Total Transport Cost

The transport cost of a project can be estimated by the sum of costs for each leg of the carbon chain, adjusted by the quantity of CO_2 stored. We calculate the costs for the example projects as follows and suggest that these formulae can be applied generally. We define the unit cost, U, as the cost in \$/t-km for the mode and product in subscript; for example $U_{truck,BM}$ is the cost of trucking biomass per t-km. For rail and pipeline, U depends on distance and flowrate.

For the biomass by truck scenario, where the conversion facility is located near the storage site:

$$T = \frac{dU_{truck,BM}}{(1-W_c)f_{CO2}} + d_{spur}U_{pipeline}$$

where T is the total cost in \$/t-CO_2 stored, d is the distance between biomass pick up and the conversion plant (typically the longest part of the chain), and d_{spur} is the length of the short pipeline from the plant to the injection site. W_c is the water content of the biomass and f_{CO2} is the storage factor for the type of plant.

For biomass by rail:

$$T = \frac{d_{local}U_{truck,BM} + dU_{rail,BM}}{(1-W_c)f_{CO2}} + d_{spur}U_{pipeline}$$

CO_2 by truck:

$$T = \frac{d_{local}U_{truck,BM}}{(1-W_c)f_{CO2}} + dU_{truck,CO2}$$

CO_2 by rail:

$$T = \frac{d_{local}U_{truck,BM}}{(1-W_c)f_{CO2}} + d_{spur,1}U_{pipeline} + dU_{rail,CO2} + d_{spur,2}U_{pipeline}$$

Where $d_{spur,1}$ is the length of the pipeline at the origin station and $d_{spur,2}$ is the length at the destination station.

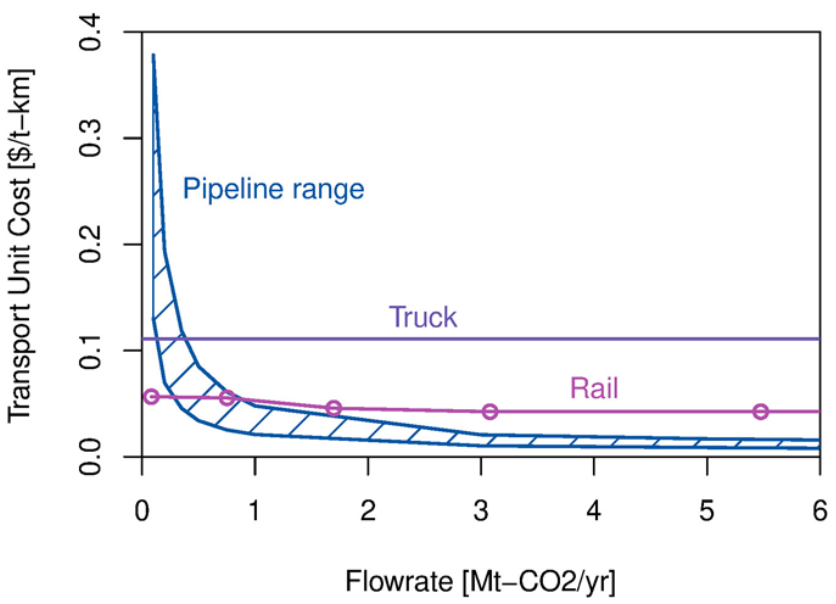

FIGURE 5 | Comparison of transport costs of CO_2 by truck, rail, and pipeline as a function of flowrate. Costs are calculated for a distance of 200 km.

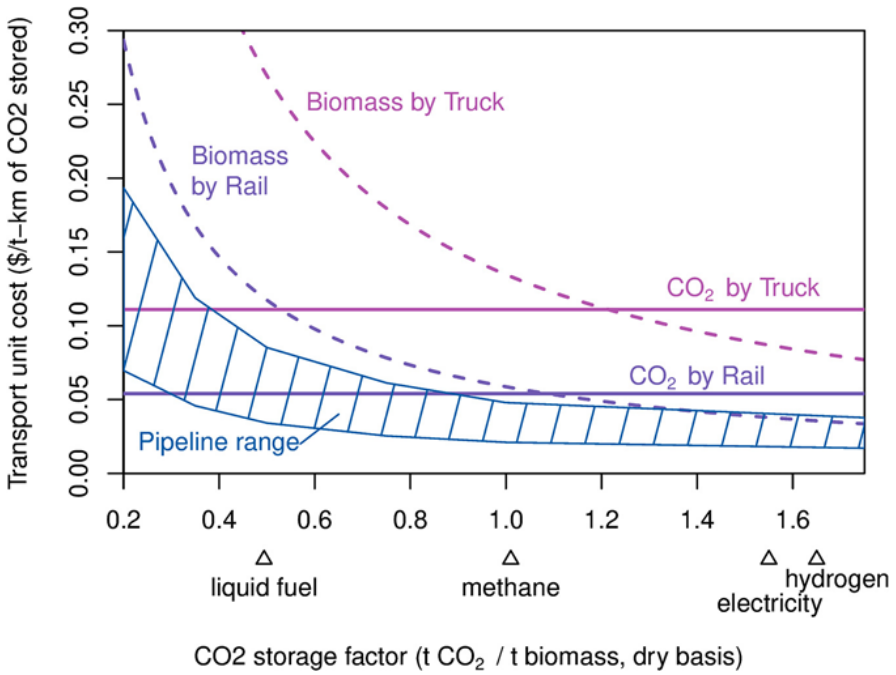

FIGURE 6 | Comparison of transport costs by mode as a function of the CO_2 storage efficiency of the project. Costs are calculated for a biomass input of 1 Mt/yr, dry basis, and 25% water content. Triangles below the *x*-axis indicate the CO_2 storage factors for several potential project types, as shown in **Table 3**. Costs reflect the long leg of transport only and neglect local collection and pipeline spurs.

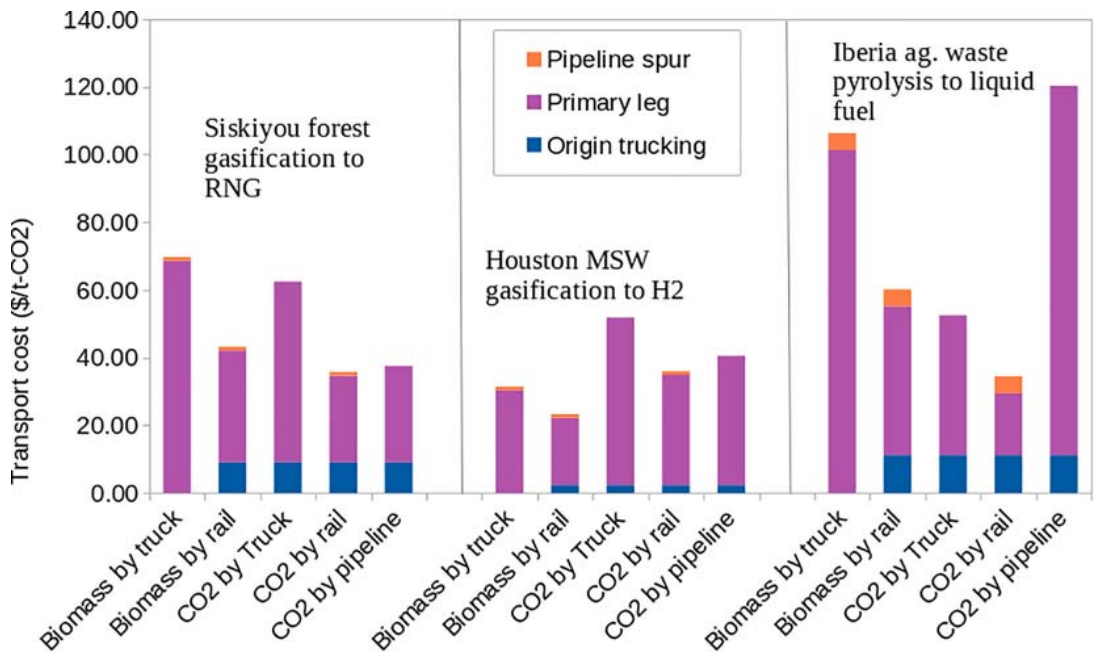

FIGURE 7 | Transport costs by mode for three example projects. Distance varies by each project, as summarized in **Table 4**.

For CO_2 by pipeline:

$$T = \frac{d_{local} U_{truck,BM}}{(1 - W_c) f_{CO2}} + dU_{pipeline}$$

These equations are used to calculate the total transport cost for the three example scenarios shown in **Table 4**. For the CO_2 by rail scenario, we assume that the plant is built near existing rail so that $d_{spur,1} = 0$, but this need not be the case generally.

TABLE 3 | CO_2 storage factors for some NNBF and BECCS projects.

Project type	Storage factor (t CO_2 stored per t biomass input, dry basis)
Biomass combustion to electricity	1.55
Biomass pyrolysis to liquid fuel	0.494
Biomass gasification to renewable natural gas	1.01
Biomass gasification to hydrogen	1.65

RESULTS

The cost of biomass transport by truck and rail is shown in **Figure 4**. We can see that rail is dramatically less expensive at longer distances. Depending on the project and incentives, biomass could be transported hundreds of kilometers by rail at a reasonable cost. However, trucking has a potential advantage at short distances. For example if biomass is being collected from forests over a large area or many farms in a region, most will not be immediately accessible to rail, so there is a consolidation step by truck. Depending on the average distance between biomass sources and the rail station, direct trucking may have an advantage. With an average truck trip of 30 km to the rail station (reasonable for a biomass-dense area like our example counties), trucks are preferred for a primary distance of about 40 km or less.

The results for transporting CO_2 are shown in **Figure 5**. In this case, we look at the dependence of the unit cost on CO_2 flowrate, which has a strong effect on pipeline cost and a slight effect on rail cost. This figure shows results for a distance of 200 km, where rail is always preferred to trucking if it is available. At a flowrate of about 1 Mt/yr and above, a pipeline is clearly preferred to rail, and below about 0.3 Mt/yr, rail is clearly the lower cost option. In between those values, the specifics of the project would be needed to determine the best option. These trends are insensitive to distance except at very short distances, where trucking might be preferred to rail for the same reason described above for **Figure 4**.

Figures 4 and **5** describe the trends for a segment of the transport chain where either biomass or CO_2 must be moved. However, if the site of the NNBF or BECCS plant can be freely selected, then we would like to know whether we should, on the one hand, site the plant near biomass sources and transport CO_2 to the storage site, or on the other hand site the plant near CO_2 storage and transport the biomass. In a biofuel or biomass combustion project without CCS, this isn't a meaningful choice: the products are easier to transport than biomass and so the plant should be located as close to biomass sources as possible. This consideration also leads to smaller optimum plant sizes. However, with CO_2 transport and storage and their associated economies of scale, the question is more complicated.

The best choice of plant location depends on the plant size and on the conversion technology being used: specifically, the ratio of CO_2 produced to biomass input. **Figure 6** shows the unit costs of the five different modes for a range of the CO_2 storage factor. Triangles under the x-axis mark the values of the factor for the BECCS and NNBF plants listed in **Table 3**. These factors are not universal; a project developer could always choose to capture less CO_2 (or in some cases slightly more), but the values are constrained by the thermodynamics and stoichiometry of the products and input biomass.

For low storage factors, represented by pyrolysis to liquid fuels, transport of CO_2 is favored over transport of biomass across modes. However, the total volume of CO_2 is low enough that CO_2 by rail competes with a CO_2 pipeline. At a low enough factor, rail is clearly favored because the volume of CO_2 is not enough to make the capital investment in a pipeline worthwhile. However, this depends on the plant size. This figure is calculated for a fixed biomass input of 1 Mt/yr (dry basis). A larger plant would tend to favor a pipeline even at the smaller storage factors, while a smaller plant would favor rail even at higher storage factors. Only the pipeline cost is sensitive to plant size in this way, the relative costs of other modes don't change much with plant size.

At high storage factors, represented by a gasification to hydrogen project or combustion to electricity, it becomes less expensive to transport biomass by truck or rail than CO_2 by the same mode. The overall volume of CO_2 is large enough that a pipeline is still the lowest-cost option, overall, but this result is sensitive to the plant size. Even at 1 Mt/yr biomass, which is small compared to existing coal gasification plants, but large compared to almost all existing biomass plants, biomass by rail is marginally competitive with a CO_2 pipeline. If constructing a pipeline is not possible due to practical or legal restrictions, biomass by rail appears to be a viable alternative, allowing a developer to bridge hundreds of kilometers of distance between biomass source and geologic storage site for about \$10/t of CO_2 stored. This is a modest price compared to the likely cost of capture and to the cost of alternative carbon removal technologies, like direct air capture.

TABLE 4 | Transport characteristics for three example NNBF projects.

Scenario	Siskiyou forest residue gasification to RNG	Houston MSW gasification to H_2	Iberia agricultural waste pyrolysis to liquid fuel
Average local trucking distance (km)	64	34	41
Road distance to nearest storage (km)	480	446	372
Rail distance to nearest storage (km)	529	671	370
Pipeline distance to nearest storage (km)	514	703	658
Storage site distance to plant or rail (km)	20	20	30
Biomass flow (Mt/yr, wet basis)	0.94	0.73	0.88
CO_2 flow (Mt/yr)	0.66	1.08	0.32

At an intermediate carbon storage factor, such as one achieved by gasification followed by methanation to make renewable natural gas, CO_2 transport by rail and biomass transport by rail are roughly equal cost. CO_2 transport by pipeline is lower cost than both, though again this would change for a significantly smaller plant.

These results suppose that the CO_2 pipeline is dedicated to a single plant. A shared CO_2 pipeline would quickly reduce transport costs and favor the pipeline mode. Indeed, the distance of interest in a project is quite possibly the distance to a shared CO_2 trunk line rather than a storage site. For example, a trunk line which unites the flows of about 9 hydrogen projects of the benchmark size (combined 10 Mt/yr) could move that CO_2 over 1,000 km for $10/t (model average). Geographic opportunities are significantly expanded this way, but a shared CO_2 pipeline also poses challenges of coordination and capacity planning.

The results so far are meant to reveal the general features of the transport problem and mostly apply to the longest segment of the transport chain. To understand the relative importance and the approximate costs of the other segments, we will look at several example projects. The total transport cost can't be calculated without reference to local distances, proximity to rail, and specifics of the conversion plant. However, we can get some insight by looking at several plausible example projects. Based on our previous study of carbon removal in California and on previous demonstrations of CO_2 storage in the southeastern U.S., we propose three projects that convert biomass waste or residues and store CO_2 in a geologic formation. Locations of the projects and proposed routes are shown in **Figure 3**.

The calculated distances for components of the five transport scenarios are shown in **Table 4** with other characteristics of the example projects. Calculated distances range from 370 km for the Iberia rail route to 700 km for the Houston pipeline route. All three scenarios traverse relatively long distances; the average source-to-storage distance calculated in Baker et al. (2020) was only 70–160 km, depending on biomass type. In a case study matching industrial CO_2 sources to sinks in Pennsylvania, Psarras et al. (2017) found transport distances of 64–140 km. Assessing CO_2 storage from ethanol refineries, Sanchez et al. (2018) found 4 Mt/yr of abatement within 80 km of a storage site across the U.S., however, with sufficient incentives and a shared pipeline network, system average travel distances grew to over 1,000 km. The three scenarios proposed here may inform the bounds of what can be implemented without a shared CO_2 pipeline.

Figure 7 shows the estimated total transport costs for each of the three example projects via each of five modes. For Siskiyou forest biomass, the lowest cost option is to site the plant at the source and transport the CO_2 530 km by rail to the storage site, giving a total transport cost of $36/t-$CO_2$ stored. However, this is virtually tied with transporting the CO_2 by pipeline ($37/t); either may be preferred based on the specifics of the project and pipeline route. Note that these costs start at the roadside and do not include collection of the biomass from the forest and grinding. In California, these efforts are likely to be supported by fire-management activities or by commercial timber harvesting, in the case of sawmill residues, but contract prices for biomass will vary.

Transport costs are overall lowest for municipal solid waste from the Houston area. This is because gasification to hydrogen has the highest CO_2 storage factor, making transport less expensive per unit CO_2, and to a lesser extent because MSW has a lower water content. The best option here is to transport the biomass by rail to a plant near the storage site and then move the resulting CO_2 via a short pipeline spur, giving a total transport cost of $24/t-$CO_2$. However, if the existing CO_2 pipeline could be contracted for this project, it would likely cut the cost of pipeline transport by an order of magnitude, putting the total transport cost for the CO_2 pipeline scenario in the single digits.

The Iberia agricultural waste scenario has the largest truck and pipeline costs. This is because the low CO_2 storage factor for pyrolysis to liquid fuels results in less efficient use of the biomass in the first case and smaller flows of CO_2 in the latter. However, the pyrolysis scenario produces the most valuable co-product (liquid fuel), so transport costs may be offset. The best option for this scenario is to site the biofuel plant in Iberia County and transport CO_2 by rail to Mobile, giving a total transport cost of $34/t-$CO_2$. This includes pickup of biomass by truck at the farm gate, but not collection from the field and possible pre-treatment for transport (see **Table 1** for those).

As noted, there is an existing CO_2 pipeline that covers most of the distance between Iberia and Mobile counties. If project developers can contract to use this pipeline, then only an additional 146 km would need to be constructed (22% of the total route). However, even constructing that length is costly in this scenario because of the small flowrate of CO_2. If using the existing pipeline was free, the pipeline mode would still cost $35/t, slightly more than CO_2 by rail.

CONCLUSION

We have assessed the transport costs for carbon removal projects based on biomass conversion with carbon capture and storage in the United States. We used publicly available cost data and techno-economic analyses from the literature to compare transport modes and calculate total transport costs for several example projects. Overall, we find that biomass sources and CO_2 storage sites can be connected across several hundred kilometers for costs in the range of $20–40/t-$CO_2$ if the developer has at least some flexibility in choice of transport mode and type of plant. Reasonable costs can be achieved via rail if a pipeline is not possible, but much longer distances can be spanned if shared CO_2 pipelines are used.

Transport costs are highest for liquid fuel projects and lowest for hydrogen production and large electric plants. This is due to the higher ratio of CO_2 stored per unit biomass in the latter. Also for these projects with high CO_2 storage ratios, transport of biomass by rail becomes a competitive alternative to CO_2 transport by pipeline. For small projects or very low carbon storage factors, CO_2 transport by rail is preferred over constructing a pipeline. For low flowrates and distances less than a few tens of km, trucking may be competitive with rail and pipelines. When rail and pipeline access are not practical, trucking is a viable alternative but at a higher cost.

These results are based on average costs in the United States. However, modal costs vary locally and internationally, especially for pipelines. If used with local unit costs, the formulae given here can be applied to estimate costs and compare modes. The specific crossover points for preferred mode versus plant size or carbon storage factor will change, but the broad trends will apply wherever the cost of order of truck, rail, and pipeline holds.

Our analysis suggests that developers or policymakers who hesitate on carbon removal projects because of the perceived difficulty of building pipelines should strongly consider rail as either a permanent or intermediate alternative. Even large projects can operate on existing infrastructure at a reasonable cost of transport. However, policymakers designing incentives should expect transport costs of up to a few tens of dollars per ton-CO_2 until a shared pipeline system is constructed.

DATA AVAILABILITY STATEMENT

The original contributions presented in the study are included in the article/supplementary material. Further inquiries can be directed to the corresponding author.

AUTHOR CONTRIBUTIONS

JS conducted analysis and contributed the bulk of text for this manuscript. SP and WL each conducted analysis on biomass conversion technologies and contributed text and strategic direction. HG and SB contributed assessment of biomass characteristics and availability. WK contributed geographic analysis and figures. SB and RA contributed conceptual model design and strategic direction. All authors contributed to the article and approved the submitted version.

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