Evaluating technology options to mitigate greenhouse gas emissions

Proceedings:
CCS Cost Network 2023 Workshop

12-13 April, Groningen, Netherlands

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IEA GREENHOUSE GAS R&D PROGRAMME

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Blazing the way to net zero with leading CCS research. *We advance technology to accelerate project development & deployment.*

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

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Acknowledgements & Citations

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EXECUTIVE SUMMARY

The 7th edition of the IEAGHG CCS Cost Network Workshop was hosted at the University of Groningen, Netherlands, on 12-13 April 2023. The purpose of the workshop was to share and discuss the most current information on the costs of carbon capture and storage (CCS) in various applications, as well as the outlook for future CCS costs and deployment. For the first time, this workshop also included a session on the direct capture of CO_2 from the atmosphere. The workshop also sought to identify other key issues or topics related to CCS costs that merit further discussion and study.

The workshop was structured into five technical and three breakout sessions:

- The first session, chaired by NETL's Timothy Fout, addressed the cost of CCS industrial applications with a focus on cement production.
- In the second session, chaired by UKCCSRC's Jon Gibbins, the cost of CCS in power plant applications was addressed, with a focus on recent Front End Engineering Design (FEED) studies.
- Howard Herzog (MIT) chaired the third session on direct air capture (DAC), which included discussions on the cost of DAC and DAC case studies focusing on sorbent and solvent systems.
- The fourth session on offshore CO_2 transport and storage was chaired by Sean McCoy (University of Calgary). In this session, the costs relating to offshore storage and lessons from the Aramis project were explored.
- Finally, the fifth session chaired by Machteld van den Broek (University of Groningen), addressed the outlook for CCS deployment and costs as reflected in large-scale energy-economic and integrated assessment models used for scenario and policy analysis.

During the breakout sessions, high capture efficiencies, blue/green hydrogen, and the outlook for onshore transport and storage costs were explored. The sessions were moderated by Jeffrey Hoffman (US DOE), Niall Mac Dowell (Imperial College London), and Candice Paton (Enhance Energy, Canada) respectively, providing in-depth discussions and insights into these critical topics.

Key takeaways from the workshop were:

- The cost of the full CCS value-chain is significantly influenced by geographical location, and the costs for heat and/or electricity. It was emphasised that within Europe, CCS projects lacking funding support struggle to present a positive business case. Additionally, the development of CO_2 infrastructure was identified as crucial for harnessing the full potential of CCS in the cement industry.
- The FEED for Mustang Station outlines a technically feasible design with a capital cost of USD 725 million. The cost per tonne of CO_2 at USD 3/MMBTU varies, ranging from USD 85 at 4% IRR with an 85% load factor to USD 166 at 10% IRR with a 52% load factor. Significant opportunities for improving performance and reducing costs include steam extraction from existing turbines, increasing absorber packing for more than 97% CO_2 removal, and expanding exchanger areas to lower natural gas usage.
- The detailed public FEED sets the groundwork for potential natural gas combined cycle (NGCC) or combined heat and power demonstrations (CHP), with ideal site characteristics including the availability of cooling water, steam extraction capability, low reliance on renewables, and a high load factor.

- Achieving over 1 Gtonne of carbon dioxide removal capacity requires early, significant CDR purchases, fair pricing, and long-term offtake agreements. It also necessitates government subsidies, clear policy frameworks, site development with adequate storage and renewable energy, advanced, cost-effective technology, supply chain optimisation and low-cost financing with sufficient third-party funding.
- To optimise storage and transport costs in CCS, hubs are essential due to the uneven distribution of sources and variable injectivity. A comprehensive evaluation of total transport and storage costs at hubs requires analysing various cost elements, including onshore and offshore pipelines, and shipping. Facilities required at loading and unloading locations will significantly impact total shipping cost.
- Further regional analyses are required to better understand where CCS might be most effective. While the IEA study suggests CCS viability is predominantly in emerging economies, a more detailed country-level analysis is necessary to fully evaluate the potential of CCS.
- To accelerate the advancement of CCUS, governments and industries should focus on four high-level priorities: creating favourable conditions for investment, targeting the development of industrial clusters with shared CO_2 infrastructure, identifying, and developing CO_2 storage solutions, and boosting innovation in key technologies.
- It is technically possible for both coal-fired and natural gas combined cycle power plants to reach net zero emissions with CCS, achieving about 400 ppm CO_2 in the exhaust gas. Solvent intercooling is crucial for high CO_2 capture efficiency, particularly in NGCC plants. When operating at high-capacity factors, both pulverised coal (PC) and NGCC plants can attain zero-emissions using CCS at competitive costs. However, at lower capacity factors, combining CCS with DAC could be more effective for full decarbonization, provided DAC costs align with current claims.
- For blue/green hydrogen, arguments about “the best” technology is currently a distraction. All possibilities should be welcomed that enable low-carbon production, moving away from “colours” and focus on carbon intensity (CI) scores. Further, building confidence across the value chain is key.
- In North America, the cost of transport and storage in CCUS projects ranges from USD 10/tonne to USD 100/tonne of CO_2 stored. Key challenges for onshore projects include liability management and perceived risks, which lead to uncertainties and can drive up costs. Opportunities for cost reduction lie in adopting more appropriate risk based MMV practices, transitioning midstream pipeline systems from 'one-to-one' to 'many-to-many' systems, implementing focused government regulations for open access and transparent tariffs, and coordinating infrastructure development. Improved policies and frameworks for risk discovery.

The 7th IEAGHG CCS Cost Network Workshop successfully convened global CCS experts to discuss the costs and costing methodologies relating to CCS. Key insights included the significant influence of geographic location and energy costs on CCS project viability, and the need of government support and clear policy frameworks for CCS advancement. The workshop highlighted the potential of CCS in heavy industries, e.g., cement, and the crucial role of CO_2 infrastructure development. It underscored the importance of regional analyses for CCS effectiveness, the need for investment-friendly environments, and the significance of shared CO_2 infrastructure in industrial clusters. The discussions also emphasised the technical feasibility of using CCS to achieve net zero emissions in coal and natural gas power plants, the need for holistic approaches in decarbonisation technologies, and the challenges inherent in establishing costs for both onshore and offshore transport and storage.

More information on costs may be found in IEAGHG reports and in previous workshop proceedings, all of which may be accessed on IEAGHG’s website.

WORKSHOP AGENDA

12 APRIL 2023 (DAY 1)

09:15 Welcome
09:30 **Session 1: Industrial Capture**, *Chair: Timothy Fout*
- Jan Theulen (Heidelberg Materials): View on costs of CCS value chain
- Simon Roussanaly (SINTEF): Techno-economic analysis of solvent-based CO_2 capture from cement)

Discussion
11:00 Break
11:30 **Session 2: FEED studies**, *Chair: Jon Gibbins*
- Bill Elliot (Bechtel): The cost of carbon capture plants; say it ain't so, Joe
- Jorge Martorell (Univ. of Texas at Austin): Lessons learned: Mustang FEED and comparison to Panda FEED

Discussion
13:00 Lunch
14:00 **Session 3: Direct Air Capture**, *Chair: Howard Herzog*
- Jan Wurzbacher (Climeworks): Scaling and cost projections of carbon dioxide removal (CDR) via direct air capture (DAC)
- Tim Fout (DOE/NETL): Direct air capture case studies

Discussion
15:30 Break
16:00 **Session 4: Offshore CO_2 Transport and Storage**, *Chair: Sean McCoy*
- Johannes Kalunka (ExxonMobil): South East Asia CO_2 source sink mapping to optimize transport cost using pipelines and ships
- Sander Nijman (Shell) and Boudewijn Reniers (TotalEnergies): ARAMIS- A large-scale CO_2 transport service enabling offshore storage

Discussion
17:30 Adjourn, Day 1
19:30 Dinner *(Sponsor: GCCSI)*

13 APRIL 2023 (DAY 2)

09:00 **Session 5: Outlook/Scenarios for CCS**, *Chair: Machteld van den Broek*
- Harmen Sytze de Boer (PBL): Impact of CCS costs on deployment of CCS in IAMs
- Mathilde Fajardy (IEA): CCUS in IEA scenarios

Discussion
10:30 Break
11:00 Breakout Sessions
Breakout 1: High capture efficiencies, *Moderator: Jeffrey Hoffmann*
- Tianyu Gao (EPRI), et al., Zero emissions fossil fired power plants using conventional post- combustion CO_2 capture
- Mathieu Lucquiaud (Univ. of Sheffield): On the cost of (truly) zero carbon hydrogen with CCS

Breakout 2: Blue /green hydrogen, *Moderator: Niall Mac Dowell*
- Niall Mac Dowell (Imperial College London): Some reflections on the "hydrogen economy"

Breakout 3: Onshore transport and storage costs, *Moderators: Sean McCoy & Candice Paton*

12:30 Lunch
13:30 **Closing Plenary**: Breakout session reports and discussion, *Chair: Howard Herzog*
14:45 Adjourn

INTRODUCTION

The seventh meeting of the CCS Cost Network Workshop was held on April 12-13, 2023 at the University of Groningen in the Netherlands, under the auspices of the IEA Greenhouse Gas R&D Programme (IEAGHG).

The meeting was organised by a Steering Committee co-chaired by Keith Burnard (IEAGHG) and Machteld van den Broek (University of Groningen) with Secretariat support from Abdul'Aziz A. Aliyu (IEAGHG), and representatives from: Carnegie Mellon University (Ed Rubin), Electric Power Research Institute (Abhoyjit Bhown), International Energy Agency (Sara Budinis), Massachusetts Institute of Technology (Howard Herzog), Monea CCS Services Ltd (Mike Monea), University of Calgary (Sean McCoy), University of Sheffield (Jon Gibbins) and the USDOE National Energy Technology Laboratory (Tim Fout).

The purpose of the workshop is to share and discuss the most current information on the costs of carbon capture and storage (CCS) in various applications, as well as the outlook for future CCS costs and deployment. For the first time, this workshop also included a session on the direct capture of CO_2 from the atmosphere.

The workshop also seeks to identify other key issues or topics related to CCS costs that merit further discussion and study.

Day 1 of the meeting was devoted to four plenary sessions on topics of interest. Each session included two invited presentations followed by a discussion among workshop participants. Day 2 included a fifth plenary session followed by three parallel breakout sessions pursuing selected topics in more detail. Reports from each breakout group were presented in the final plenary session.

This Proceedings presents a brief summary of each session plus the slide presentations by invited speakers. Special thanks to University of Groningen graduate students Herian Atma, Rebeka Béres, Dmitry Bublik, Sebastian Mulder, Longquan Li, and Auke van der Wel for assistance with session summaries. This and all previous CCS Cost Network proceedings are available online from the IEAGHG.

SESSION SUMMARIES

Session 1: Cost of CCS in Industry

Chair: Timothy Fout, USDOE/NETL

Presentations:
Jan Theulen, Heidelberg Materials, Norway;
Simon Roussanaly, SINTEF Energy Research, Norway

This session addressed the cost of CCS in industrial applications, with a focus on cement production. Two presentations were followed by a general discussion. Key points are summarised below.

Deep decarbonisation of cement production

Jan Theulen first discussed the cost of deep decarbonisation of cement production. He presented the status of his company's plans for CCS in their cement production plants. They are developing in Norway the largest CCS facility for cement worldwide, scheduled to begin operations in 2024 and targeted to capture 10 Mt CO_2 cumulatively by 2030.

Elements of CCS cost drew on data and published reports by others. In general, the capex of the CCS system increases with more detailed stages of design (pre-FEED, FEED, detailed design) and has escalated also due to recent inflation and supply chain issues. Their conclusion regarding the entire CCS value chain cost for the cement sector in the EU in 2026-2030 is that CCS projects are still not profitable without funding support, even when the carbon price of the EU Emissions Trading System (ETS) is equal to the CCS cost. They found that the costs of transport and storage can have a major influence on the overall cost of CCS.

CO_2 capture costs in industry

Simon Roussanaly next presented results from a techno-economic analysis of the cost of CO_2 capture and conditioning for cement plants in Germany and Poland, as part of the EU-sponsored ACCSESS project. The analysis followed recently-developed guidelines for first-of-a-kind (FOAK) projects. Capital costs of the solvent-based capture systems were dominated by the absorber, regenerator and flue gas conditioning sections (which included compression). The cost of CO_2 avoided for only capture and conditioning was estimated to be 108 and 118 €/tCO_2 for the Polish and German plants, respectively. Two additional studies of CCS for a pulp mill in Sweden and a waste-to-energy plant in Switserland broadened the range of avoidance cost for capture and conditioning to 80-120 €/tCO_2. These studies highlighted that for inland European industrial plants, transportation costs can have a major impact on overall CCS costs. For the four FOAK facilities analysed, the avoidance cost ranged from 100 to 280 €/tCO_2 including transport to a harbor. Storage costs (not evaluated) would further increase these totals.

General discussion

This session highlighted the fact that cement plants have some unique attributes compared to other industrial sectors. They are usually located inland, far from the coast, so that CCS costs are sensitive to the specific geographic conditions, especially for CO_2 transport and storage (T&S). The capture system design will be highly dependent on the fuel utilised in the cement plant for both power production and calcination, as opportunity fuels are often utilised.

Both presenters also stressed the immediacy of the need for CCS in the cement sector. Theulen mentioned the need for EU or other governmental regulations that require the use of low-carbon cement in order to maintain competitiveness in the global market. Marketing opportunities for decarbonised cement products also may be available to assist in the funding of CCS projects. For example, Roussanaly reported that CCS implementation in cement and steel production could greatly reduce emissions from building a bridge with these materials. A recent study found a high benefit/cost ratio that could be a driver for low-carbon procurement in the construction sector.

Several additional points emerged in the general discussion:

• Although current plans for the Heidelberg Materials plants are for a capture efficiency of 90%, higher capture efficiencies up to 99% will not increase overall costs significantly. The use of biological materials and other alternative fuels for heating directly in the cement plant is another pathway to achieve higher net capture rates;

• Cement plant owners are not currently involved in the transportation and storage of captured CO_2 from their plants. The industry requires other entities to provide these as a service;

• The cement sector is energy-intensive and contributes significantly to GDP. People may be willing to pay more for cement products with a lower carbon footprint;

• Currently, 90% of the costs for industrial CCS projects are covered by government subsidies. Increased financial support from industry and the private sector would allow for faster development and deployment.

Session 2: Power Plant FEED Studies

Chair: Jon Gibbons, University of Sheffield

Presentations:
Bill Elliott, Bechtel Corporation, US;
Jorge Martorell, Univ. of Texas at Austin, US

This session addressed the cost of CCS in power plant applications, with a focus on recent Front End Engineering Design (FEED) studies. Two presentations were followed by a general discussion. Key points from this session are summarised below.

The cost of carbon capture plants

Bill Elliot provided an overview of recent cost trends and volatility associated with CCS projects. He first noted the long history of amine-based post-combustion capture, with no changes in the basic technology since Bottom's original patent in 1930. Regarding costs, however, Elliot showed that the Chemical Engineering Plant Cost Index (CEPCI) had risen by 36% between 2020 and 2022, resulting in significantly higher capital costs than just a few years ago. He also noted that the sub-indices for equipment and buildings also saw significant increases, while those for construction labor and engineering supervision remained relatively stagnant.

A 2021 FEED study for an MEA-based post-combustion capture (PCC) retrofit to the Panda Sherman NGCC plant in Texas was used as an example of the current cost breakdown. The capital cost of the plant had the largest impact on the \$/ton CO_2 captured in comparison to other cost items, including maintenance, energy, personnel, solvent consumption, waste disposal, and other operating costs.

With an assumed plant capacity factor of 57% and a loan life of 15 years, the CO_2 capture cost at Panda Sherman NGCC was calculated to be about \$83/tCO_2 captured. This cost would be lower if the capacity factor of the plant were higher and/or the loan life of the project longer. Other important assumptions were the interest rate and return on equity. The PCC plant also was sized to handle about the minimum stable generation flue gas flow from the power plant, thus ensuring the highest possible capital utilisation.

Elliot noted that for power plant applications it is very important to understand and conform to the electricity market in which the plant operates. Panda is part of ERCOT, the Texas-only energy-based market, which is characterised by long periods of operation with an excess of capacity over demand and dispatch at, or close to, marginal operating costs with occasional price spikes. The capture plant is not operated during those limited periods when the ERCOT power grid has elevated prices (up to \$9,000/MWh), for which the average foregone electricity revenue was estimated at \$25/MWh, contributing \$13/tCO_2 captured.

Lessons learned from two FEED studies

Jorge Martorelli gave a two-part presentation, first discussing a FEED study for the retrofit of a piperazine-based capture system to the Mustang NGCC station in Texas, then comparing those results to the Panda Sherman FEED study discussed by Bill Elliot.

The Mustang FEED study, conducted in 2022, brought significant updates to most of the key assumptions in a 2019 initial proposal. The major changes included fuel cost (from \$2/MMBtu to \$8/MMBtu), electricity price (from \$20/MWh to \$100/MWh), and capital cost (\$270 million to \$725 million). The resulting CO_2 capture cost at the Mustang station ranged from \$52/tCO_2 to \$85/tCO_2, depending on the assumed capacity factor and rate of return for project financing.

Major suggestions for reducing the cost included extracting steam from the existing turbines instead of using an additional gas-fired steam boiler; using more absorber packing to get about 97% CO_2 removal; and providing additional heat exchanger area to reduce thermal energy requirements (a 16% cost reduction with twice the area).

A cost comparison of the Mustang and Panda Sherman FEED studies was done by scaling the Mustang plant costs to the Panda design capacity using a 0.6 power law, with Panda's costs adjusted using the same site constraints for ductwork etc. as the Mustang plant. The US 45Q tax credit was included as part of the cost calculation for both CCS projects. The key conclusions were:

- Estimates for both FEED studies were similar after adjusting for capacity;
- Ancillary equipment costs had a higher impact than expected;
- Ancillaries at Mustang offset the cost advantage of the 2nd generation piperazine process;
- The 45Q tax credit would incentivize CO_2 capture at the auxiliary boiler alone at the Mustang unit;
- Site-specific factors such as availability of cooling water or extracted steam have a significant impact on cost;
- Cost models that exclude items like ductwork and utilities leave out significant costs which can change the optimal design.

General discussion

The general discussion for this session called attention to differences between the US and Europe in requirements for securing government funding for FEED studies for green projects such as CCS. The US was seen to have less rigorous requirements compared to the EU or UK. Therefore, US FEED studies for CCS do not necessarily mean that the projects are going to be implemented at full scale in the near future.

Unlike the EU and UK, the US had not yet implemented either a carbon pricing or emission trading system. Thus, the incentives and motivation for developing low-carbon technology such as CCS is quite different from the EU and UK. Most of the current initiatives on CCS projects in the US have been dependent on government subsidies or other schemes (e.g., 45Q tax credits) to cover the majority of capital costs.

In general, there was low confidence at this meeting that a large-scale CCS power plant project would happen in the US under the current regulatory and incentive frameworks and market conditions. All US demonstration projects for CCS to date were largely a result of government funding being made available. Discussants stated that US industry's appetite for larger-scale projects was limited because no one wants to be an early mover for more than demonstration projects when there are limited economic incentives to do so.

Session 3: Direct Air Capture

Chair: Howard Herzog, MIT

Presentations:
Jan Wurzbacher, Climeworks, Switzerland
Tim Fout, USDOE/NETL, US

This session addressed the cost of Direct Air Capture (DAC) systems that remove CO_2

directly from the atmosphere. Two presentations were followed by a general discussion. Key points are summarised below.

Cost of DAC

Jan Wurzbacher discussed the costs of Climework's existing plants and estimates of future project costs. While exact costs are proprietary, Climework's website indicates that carbon dioxide removal services can be bought for $1200 per tonne of net carbon dioxide removed. Significant price drops are expected in the coming years with next-generation, so-called structured sorbent technology, which enhances plant throughput while limiting energy consumption.

Looking to the future, Wurzbacher stated that DAC is central to enable a net-zero world, and that the technology can reach competitive cost levels when scaled beyond multi-megaton levels. He noted that DAC maturation and cost reductions happen in the field as the technology is implemented.

DAC case studies

Tim Fout next summarised two USDOE/NETL studies estimating the cost of DAC for sorbent and solvent-based systems. He highlighted the solid sorbent-based system designed for 100,000 tCO_2/y net removal capacity after accounting for emissions from an auxiliary NGCC-CCS plant providing steam and electricity for DAC. The cost of the integrated system was estimated at \$500-900/tCO_2 net, including the costs of CO_2 transport and storage. Alternative cost factor assumptions gave a wider range of costs, roughly \$100–1000/tCO_2 or more, net. These values contrast with a desired cost of \$100-300/tCO_2 net. Fout noted that these cost estimates did not represent either first-of-a-kind (FOAK) or Nth-of-a-kind (NOAK) costs, but rather a consistent methodology applied by NETL for commercial systems.

Cost drivers and metrics

Both Fout and Wurzbacher believed the most important drivers for steep cost reductions will be improvements in sorbent material (structured sorbents), supply chain optimisation, and a significant reduction in low-carbon energy costs. Inexpensive, low-carbon energy is a key requirement for the successful deployment of DAC since CO_2 emissions from energy use must be taken into account when determining the net carbon removal. These and other emissions in the life cycle of a DAC project can have a significant impact on the cost of DAC as a climate change mitigation option.

Both presenters also stressed the importance of differentiating between the many ways \$/tCO_2 is defined in different studies. For example, it can be on a gross or net basis, where net can include direct (site-specific) emissions and/or indirect emissions elsewhere. Such assumptions make a huge difference in cost results presented by different studies.

General discussion

In the general discussion, several additional factors affecting DAC costs were highlighted:

• *Spacing*: Spacing of the DAC units on site is crucial and under-researched for large-scale systems. As a result, studies can be too optimistic about land requirements. The spacing design of Climeworks' Orca project in Iceland leads to 5-10% of airflow overlapping in DAC units due to parallel spacing.

• *Weather conditions:* High humidity is unfavourable for Climeworks' DAC, as are very cold weather and storms. Wurzbacher stated that future DAC and sorbent development will focus on robustness against a wider range of weather conditions.

• *Siting:* Sites can be concentrated in 'sweet spots' (e.g., Iceland) where the most important drivers of site selection are cheap energy and CO_2 storage options. Weather conditions can also play a role in site selection, but energy costs are the main drivers of optimal location. The share of energy required for the Orca design is about

20% electricity 80% heat; hence, the focus is on affordable low-carbon heat for site selection (e.g., geothermal).

• *Infrastructure:* Existing industrial pipelines are not optimal for CO_2 distribution. The presenters could not recall a study looking into existing pipeline risks when adapted to CO_2 transport and acknowledged the issue is understudied. Additionally, the DAC capture rate must be matched with post-processing and infrastructure capacities (such as pipeline injection rate capacities) to avoid operational and profitability problems.

Session 4: Offshore CO_2 Transport and Storage Costs

Chair: Sean McCoy, University of Calgary

Presentations:
Johannes Kalunka, ExxonMobil, US
Boudewijn Reniers, TotalEnergies. France; and
Sander Nijman, Shell, US

This session addressed the cost of CO_2 transport and storage (T&S) in offshore formations. Recent cost estimates for projects such as Northern Lights in the Netherlands are far greater than those of a decade ago. Thus, the aim of this session was to understand current estimates of offshore CO_2 storage costs, the drivers of cost, and whether we can expect these costs to fall in the future. Two presentations were followed by a general discussion. Key points are summarised below.

Offshore storage in Southeast Asia

Johannes Kalunka first presented optimised storage costs in Southeast Asia based on source-sink mapping. For that region, he identified 11 $GtCO_2$ of storage resources in depleted fields, 42 $GtCO_2$ in “field-scale” saline formations, and 275 $GtCO_2$ in “basin-wide” saline formations. These resources have an injectivity that varies from 0.1 to 1.5 Mt/y per well. He then reviewed how ExxonMobil combined the resource data with publicly available cost estimates for compression and dehydration, onshore and offshore pipelines, liquefaction, and shipping, to estimate total T&S cost for CO_2 sources in Singapore. Those costs ranged from \$50-\$75/tCO_2 for the first gigaton of CO_2 and from \$75-\$150/tCO_2 for the next six gigatons. The cost curve slopes steeply upwards for additional amounts (up to around 9 $GtCO_2$ total).

For most cases, offshore transport is the costliest component of the chain in Southeast Asia. The cost of subsurface storage is typically small, particularly for small total quantities of CO_2. However, there are trade-offs between the cost of offshore transport and storage as the cumulative amounts of CO2 increase, mainly due to the need for larger, more costly storage sites involving shorter transport distances. Kalunka concluded that hubs have an important role to play in the region and cautioned that more detailed evaluation of options for given sources are needed for project development.

The Dutch Aramis Project

Next, Nijman and Reniers reviewed the development of the Aramis Project in the Netherlands and the key drivers of their value chain design. The project, now in the design phase, is expected to advance to a FEED study later in 2023. The goal of Aramis is to construct open-access infrastructure with a maximum storage capacity of 22 $MtCO_2$/y in depleted gas reservoirs around 200 km offshore from Rotterdam. The project envisions a new terminal at Rotterdam harbor where CO_2 shipped there by a various modes (barge, ship, onshore pipeline) is collected and then transported by pipeline to existing offshore platforms and injected into depleted gas reservoirs.

The project developers (Shell, TotalEnergies, EBN, and Gasunie) face the challenges of managing uncertainties in costs, volumes and subsidies; generating commercial returns; and delivering an affordable system tariff for users. This is particularly challenging because each party in the project has its own perspective on risk and returns. Thus, for the initial tranche of 5 $MtCO_2/y$ capacity, the parties created a marketing entity to offer a bundled T&S package intended to support construction of infrastructure. After this, the storage operators (Shell and TotalEnergies) will independently market their storage capacity, to be accessed via the hub and pipeline infrastructure developed as part of the initial tranche.

The success of the Aramis Project is also dependent on the "SDE++" scheme in the Netherlands. This is a contract for difference that allows industry to receive a subsidy when CO_2 prices fall below the benchmark for CCS (including T&S), net of the EU-ETS price. Thus, the transport and storage tariff at Aramis has been assessed to yield a reasonable rate of return. Depending on the assumptions, the resulting tariff varies from 40€ to 100€/tCO_2 transported. Under the SDE++ scheme, all investments are depreciated over a 15-year period. Longer amortisation periods would reduce the cost per ton since pipelines, ships, and collection terminals tend to have longer lifetimes.

General discussion

These two presentations highlighted the complexity of developing a commercial CO_2 storage facility, accounting for factors not included in past cost estimates. In particular, the commercial risks involved in developing such a project are a major factor. Thus, the rate of return demanded is likely to be higher than the "utility-like assumptions" in many past cost estimates. That said, lower costs can be realised in later stages of project development once the infrastructure has been proven and there is potential competition among storage operators.

Session 5: Outlook and Scenarios for CCS

Chair: Machteld van den Broek, University of Groningen

Presentations:
Harmen Sytze de Boer, PBL, The Netherlands
Mathilde Fajardy, IEA, France

This session addressed the outlook for CCS deployment and costs as reflected in large-scale energy-economic and integrated assessment models used for scenario and policy analysis. Two presentations were followed by a general discussion. Key points are summarised below.

CCS cost impacts using the IMAGE model

Harmen Sytze de Boer presented results from the IMAGE model, a global Integrated Assessment Model (IAM) operated by the PBL Netherlands Environmental Assessment Agency. The model supports the analysis of climate change mitigation pathways for 26 world regions, providing projections of greenhouse gas emissions, energy supply, end-use energy consumption, and land use patterns for specified scenarios out to 2100.

For the scenario in which the global average temperature increase above pre-industrial levels is limited to 2°C in 2100, CCS deployment increased significantly in the second half of the 21st century from around 10 $GtCO_2$ captured/y in 2050 to around 23 $GtCO_2/y$ in 2100. This was driven primarily by higher carbon prices, which increased from \$80/tCO_2 in 2040 to \$1350/tCO_2 in 2100. CO_2 was captured from a mix of biomass, natural gas, and coal with a gradual reduction in coal-based capture approaching 2100. Storage costs were based on a 2004 study and ranged from -\$10/tCO_2 for enhanced oil recovery (EOR) to \$30/tCO_2 for other geological storage.

A sensitivity analysis in which CO_2 prices remained fixed showed that techno-economic assumptions for CCS technologies had a large impact on projected deployment. For example, in a scenario with higher transport and storage costs (more in line with current trends), CCS deployment decreased by 10-20%; with a higher capture ratio it *increased* by 10-20%. Adding a DAC option to the model had a large impact, increasing tons captured in 2100 by about 55%. On the other hand, constraining CCS deployment resulted in a failure to reach the climate target under the default assumptions.

A comparison of IMAGE results for the 2°C scenario with results from other IAMs showed that most IAMs project a significant role for CCS, but its deployment varied widely across models from less than 100 EJ to more than 400 EJ of primary energy employing CCS in 2100. Only in one IAM was CCS deployment close to zero EJ in 2100. Reasons for this wide range are likely due to different cost assumptions, technical deployment rate constraints, and other factors. More transparency in modelling methods and inputs are crucial to understand these differences and enhance the usefulness of IAMs for climate policy analysis.

CCUS in IEA scenarios

Mathilde Fajardy next presented results from the International Energy Agency (IEA) model, in which the IEA's World Energy Model and Energy Technology Perspectives modelling frameworks were merged into one comprehensive framework to assess energy system developments across 26 demand regions from 1970 to 2050. Her presentation focussed on the Net Zero Emission (NZE) scenario for 2050. In this scenario, CCS played a pivotal role, accounting for 1.2 $GtCO_2$ captured by 2030 and 6.2 $GtCO_2$ by 2050.

In the NZE scenario, CCS retrofits allowed the continued operation of existing power plants and industrial plants. Industries like steel, chemicals, and cement production found CCS to be a cost-competitive option (see presentation for cost ranges presented). Hydrogen production in this scenario was around 30% CCS-based, especially in regions with low availability of renewable electricity. Additionally, CCUS was utilized to capture CO_2 from the air and biogenic sources (up to 1.8 Gt of CO_2 removal in 2050), with 85% permanently stored and the rest used to manufacture low-carbon synthetic fuels.

Although infrastructure considerations were not modelled in detail, cost and geographical factors were exogenously specified in the IEA model. The analysis highlighted the need for accelerated CCS deployment to meet a net zero goal for 2050. Fajardy emphasised high-level priorities for governments and industry, including fostering investment conditions, developing industrial clusters with shared CO_2 infrastructure, identifying suitable CO_2 storage sites, and promoting innovation for key CCS technologies. These efforts are crucial to bridge the deployment gap since currently planned CCS capacity is only 25% of what is required in the NZE scenario in 2030.

General discussion

The general discussion for this session noted that both presentations found CCS to be a crucial and cost-effective option to reach climate targets, although perhaps less prominent than in the IPCC's 5th Assessment Report (AR5). CCS deployment is also lower in the latest (2022) IEA World Energy Outlook than in previous IEA reports. This is likely because model assumptions were changed to reflect the current low level of CCS deployment, which in turn influences long-term CCS deployment options in the model.

It was appreciated that both presenters were transparent about their techno-economic input data. It was stressed that this should be the standard practise among modellers.

Regarding future modelling work, three recommendations emerged from the discussion. First, in addition to transparency and regular updates of all input data, uncertainty ranges and sensitivity runs should be included more frequently to provide insights into robust outcomes.

Secondly, more detailed regional breakdowns of results are needed to shed light on where CCS may be most viable. In the IEA study, this appeared to be mainly in emerging economies. However, more detailed country analyses are required to assess CCS potential.

For example, the geographic-specific potential for electrolytic hydrogen is highly dependent on the local availability of renewable resources.

Thirdly, IAMs should strive to include all CCUS options in their framework, including DAC and the use of CO_2 as a feedstock for products other than aviation fuel, even if they are considered controversial.

Finally, it was suggested that the CCS Cost Network may be of help in providing the modelling community with more reliable and complete data on CCS technologies.

BREAKOUT SESSIONS

Day 2 of the workshop included three parallel breakout sessions to discuss selected topics in greater detail. Issues and discussion points arising in these sessions are outlined below.

Breakout 1: High Capture Efficiencies

Moderator:
Jeff Hoffmann, Department of Energy, US

Presentations:
Jeff Hoffmann, USDOE (for EPRI-U.Texas)
Mathieu Lucquiaud, Univ. of Sheffield, UK

This session discussed the feasibility, cost, and impacts of high CO_2 capture efficiencies. Jeff Hoffmann introduced the session by noting that most CCS cost studies and integrated assessment models assume a 90% capture efficiency for cost reporting and scenario results. However, much higher efficiencies are technically achievable. Thus, it worth knowing what the cost of higher capture rates would be, and how the results of integrated assessment models would be affected by CCS efficiencies greater than 90%.

High efficiency capture costs

In their absence, Hoffmann presented results from recent work by researchers at EPRI and the University of Texas at Austin showing the incremental costs for new power plants using amine-based systems with CO_2 capture efficiencies as high as 99% to 99.9%+. These techno-economic evaluations were based on process modeling in Aspen Plus for coal-based and NGCC power plants (see attached presentation). To date, however, IAMs have not yet used such results and assumptions in large-scale energy-economic modelling.

Zero carbon hydrogen with CCS

An industrial context for high-efficiency capture systems was provided by Mathieu Lucquiaud, who gave a presentation on the costs of zero carbon hydrogen production with CCS. The results were based on process modelling integrating gProms and Aspen Plus. The most efficient system he described achieved an effective capture rate of 100% based on the carbon content of the fuel and feedstock. In this case, CO_2 emissions were no greater than the CO_2 in air intake to the process. Systems with capture efficiencies of 95% and 90% were also described, along with results of a life-cycle analysis.

General discussion

The general discussion focused on whether high-efficiency capture designs are really achievable and reliable in the real world, and whether modelling studies are overly confident. The consensus was that much more effort and time are needed for high-efficiency CCS to be deployed in the real world. The match between technological developments and government policies also is ultra-important and will define what and when progress occurs.

Nonetheless, it was agreed that high-efficiency CCS (and associated costs) should be incorporated into integrated assessment models since it is important to see what will happen if the efficiency is increased from 90% to 99%. The capture rate can also be country specific. For example, it was reported that the Netherlands seek higher efficiencies, in part to avoid a carbon tax. Participants felt that is fairly easy and feasible to achieve 95%

capture. However, new configurations and new solvents will be needed to achieve 99%. At present, many options are on the table.

Breakout 2: Blue/Green Hydrogen

Moderator:
Niall Mac Dowell, Imperial College London, UK

Niall Mac Dowell introduced recent hydrogen developments and presented an overview of ranges in cost and emissions of different types of hydrogen production from very "green" (based on renewables) to very "blue" (based on natural gas with carbon capture). It was clear that there is not one universal definition of what is really green or blue. Additionally, life cycle emissions in the hydrogen supply chain of both renewable technologies and natural gas need to be taken into account and can change the picture considerably. Therefore, it was proposed to move away from colours and instead use indicators like total (life cycle) greenhouse gas emissions per kg or MWh (LHV or HHV) of hydrogen produced.

General discussion

The general discussion revolved around the following three questions:

Question 1. Are there synergies between "blue" and "green" hydrogen?

Blue and green hydrogen have two main similarities. First, for hydrogen to play a large role in the energy system its price must be attractive for both the demand and supply sides. Secondly, after hydrogen is produced, the infrastructure, storage options, and end-use technologies are very similar or identical for both hydrogen types, so these facilities can be shared. As a consequence, green hydrogen market development could benefit from a start with potentially cheaper blue hydrogen. As the demand for hydrogen grows, the entire hydrogen market matures.

There are also important distinctions between the two hydrogen types (besides the way they are produced). For one, the role of blue hydrogen depends more strongly on location. In Europe, for example, blue hydrogen is currently difficult due to high natural gas prices and limited resources. In Asia, however, natural gas is still relatively cheap, which makes blue hydrogen more attractive. Another important distinction is that for blue hydrogen the OPEX is high and CAPEX is relatively low, while for green hydrogen it is the other way around.

Question 2. Can we scale up the hydrogen supply chain?

Scaling up hydrogen's role in the energy system in Europe would require considerable imports from North Africa (green hydrogen) and the Middle East (blue hydrogen). The water supply required for green hydrogen also can become a geopolitical issue and result in additional energy demands for desalination.

In the EU, the option of blue hydrogen based on LNG must consider life cycle emissions such as leakage of natural gas during venting and emissions due to compression. Leakage of natural gas during production and transport can be avoided or minimised with help from modern detection methods such as drones. While green hydrogen could be produced in Europe with existing renewables, this would likely impact other demands for low-carbon electricity. It was also noted that hydrogen from coal with CCS could be considered outside of the EU.

The potential for hydrogen scale-up also depends on whether projections of as much as a ten-fold decrease in electrolyser cost are realistic. In the case of solar and wind, the seemingly optimistic projections of 20 years ago were actually realised. However, other technologies have experienced much smaller cost reductions. The consensus was that the cost of electrolysers will fall, but to not much less than 1000 USD/kW. Another problem is that there are few substitutes for the critical minerals required for electrolysers.

Question 3. At what point can we justify using "additional" low-carbon or renewable power to produce hydrogen as opposed to using it to displace high-carbon (e.g., coal-based) power?

In addition to the difficulty of justifying whether hydrogen is really produced from "additional" green power, justification of a large role for hydrogen also depends on its proper use in end-use sectors. Hydrogen can be used in the power sector, industry, and the built environment, but some end use technologies in these sectors still need years of development to reach maturity. Thus, it is unclear whether hydrogen will have a big role in the power sector as challenges still remain to be resolved.

As an intermediary phase, one idea (although expensive) is that gas turbines have two types of burners. For example, Japan plans to have 50% of its power based on hydrogen. Most industries will focus first on replacing existing hydrogen supplies with green hydrogen instead of creating new uses for hydrogen. In the residential sector, the efficiency of supply chains for alternatives to hydrogen are often better. The (perceived) safety of hydrogen may also be an issue impeding scale up.

Breakout 3: Onshore CO_2 Transport and Storage Costs

Moderators:
Sean McCoy, University of Calgary, Canada
Candice Paton, Enhance Energy, Canada

The goal of this breakout session was to explore factors driving costs for onshore CO_2 transport and storage (T&S), particularly in North America, and to compare them to offshore project costs in Europe. The ensuing discussion covered a broader range of topics including the regulatory environment, approach to business models, and liability regimes that strongly impact T&S costs.

A view from Canada

The session opened with a presentation from Candice Paton, who reviewed the legal and regulatory environment in Alberta, Canada and Enhance Energy's CCUS project in the central part of the province. Since coming online in 2020, the project has stored close to 4 million tons of CO_2 from two industrial sources—a refinery and a fertiliser production facility—in a mature hydrocarbon reservoir, where the CO_2 is utilised for enhanced oil recovery (EOR) before being permanently sequestered. A foundational project to reduce barriers to entry for future CCUS participants, it was supported by both the provincial and federal governments to include a large-diameter dedicated pipeline (the Alberta Carbon Trunk Line) for CO_2 transportation and the associated capture facilities at each of the industrial sources.

Alberta is one of few jurisdictions that has a clearly defined pore space allocation process for saline aquifer storage. Alberta has created regulatory pathways for CO_2 storage through CO_2-EOR and in saline aquifers. In 2021, a process was launched in the province to solicit project proposals for large-scale CCS hubs across the province. In late-2022 and 2023, evaluation permits were provided to 25 proponents to begin the technical, regulatory and stakeholder work required to determine suitability of future projects. The province intends to ensure that emitters can access CO_2 storage through development of open access storage hubs. Details are available on the Government of Alberta website.

Views from other jurisdictions

In the general discussion that followed, it was noted that there is a perception that in the European Union onshore storage is limited by both social factors (e.g., population density, public opinion) and policy factors (e.g., prohibitions on storage). However, this perception is based largely on the Barendrecht experience in the Netherlands over a decade ago. Participants noted that today, Denmark, Poland, Bulgaria and Romania are exploring the suitability of onshore storage projects.

In the US, both onshore and offshore storage are targeted, with the focus shifting from EOR to storage-only projects. However, there was some question as to whether onshore storage in the US would be challenged by perceived risks of pipeline transport, and by the many property owners (surface and subsurface) involved in storage project developments.

In contrast, the Middle East is moving quickly as it is not limited by social factors. However, there is a need to accelerate the development of policies and regulations to support risk reduction and liability management for commercial projects.

Significant cost drivers for onshore T&S

The group agreed that a good rule of thumb for onshore CCUS projects remains that 80% of the total cost is associated with CO_2 capture (including compression), while the costs of transport and storage account for the remaining 20%. Significant drivers of T&S costs identified by the session participants included:

- Uncertainties around pore space jurisdiction and land use rights across the US. This is challenging because there are many stakeholders to engage and compensate for property use.
- The US Underground Injection Control (UIC) Program Class VI regulations for saline aquifer storage wells have substantial post-closure monitoring requirements that add to costs.
- Uncertainties around the handling of closure and liability transfer in various jurisdictions. After long periods of time this will default to the public since there is no guarantee that storage entities will still be operating.
- Costs can vary dramatically for geological storage and are highly dependent on the storage complex. For example, a project may have to drill ten wells in one location to inject a required volume while another location with more suitable geology may need only one well to store the same volume.
- Costs for measurement, monitoring and verification (MMV) can be very high. However, these costs can fall as new techniques are developed and adopted.
- It is important to have a competitive landscape with multiple parties and multiple storage projects to reduce costs as knowledge and experience are gained.
- Onshore developments are mainly focusing on deep saline aquifers, which may require significant exploration and evaluation activities. In some cases, there may be increased risks and costs around water management and seismic activity.

Business models and regulation

A variety of business models are being applied to CCUS projects in response to different approaches to regulation of the value chain. It is important for jurisdictions and project proponents to explore how business models can best allow participants to share in risks and rewards. This has implication for developers' perceived risks, and hence the cost (or tariff) for storage.

There was consensus that open access and transparency are important principles for T&S systems. While there is a role for government regulation of parts of the value chain, competition and access to projects and infrastructure are critical to keep costs low. Capture projects depend on technology while storage projects depend on geology. Competition in these two areas was seen as highly beneficial.

Participants from the EU believed that large entities controlling infrastructure for CO_2 transport may charge high rates of return to manage perceived risks of CO_2 delivery. They may also develop infrastructure in an uncoordinated way. Government regulation of transport systems may therefore be important to ensure open access and transparent toll structures from pipeline operators. Moreover, rate regulation may enable development of larger, more efficient common infrastructure to serve multiple capture projects and storage facilities. Posted and transparent rates from midstream companies can reduce barriers to entry for large emitters and increase certainty in full value-chain projects. The EU may be trending towards regulation of CO_2 transport and more transparent rates.

Key messages from the session

- Across various jurisdictions in North America, T&S costs range (in USD) from \$10 to \$100/tCO_2 stored.
- The key challenges for onshore storage projects in many regions are liability management and perceived risks leading to uncertainties (real and perceived) that can increase costs. Opportunities for cost reduction include more appropriate risk-based MMV practices; expanding midstream pipeline systems from "one-to-one" projects to "many-to-many" systems; focused government regulation to ensure open access and transparency in tariffs and coordinated infrastructure development; and, improved policies, risk discovery and liability frameworks that reduce uncertainties and related costs.
- It is increasingly important that T&S projects consider and incorporate the rights of stakeholders such as Indigenous communities in planning and execution.
- Competition in carbon storage markets is needed to ensure the availability, cost-effectiveness and efficient use of pore space.

CLOSING PLENARY

Moderator:
Howard Herzog, MIT, US

The closing plenary session was devoted to summary reports from each of the three breakout sessions. In the general discussion, participants also affirmed the continuing value of this workshop series, whose history was reviewed by the session moderator. The next meeting of the CCS Cost Network will be planned by the Steering Committee, with a date and location to be announced.

Photo credits: M. van der Broek

TECHNICAL PRESENTATIONS

This section of the Proceedings includes the publicly available slide presentations from all plenary and breakout sessions.

Session 1: Industrial Capture

1.1. Heidelberg Materials view on costs of CCS value chain *Jan Theulen (Heidelberg Material*

Heidelberg Materials view on costs of CCS-value chain

April 2023 | Jan Theulen
12.4.2023

Heidelberg Materials

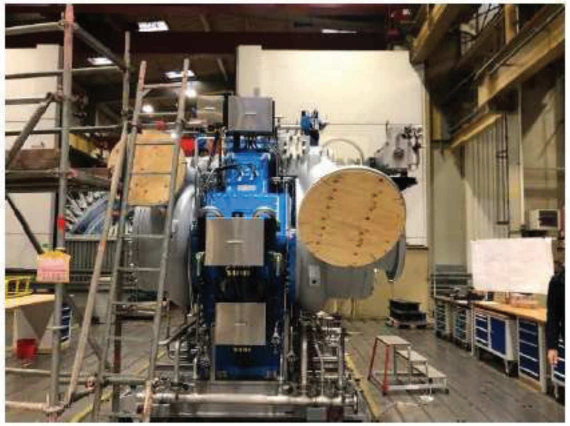
We are constructing as we speak the largest CCS-facility for cement worldwide

Absorber photographed at construction site in Holland

Module preassembled in Lithuania

Desorber

Oil lube unit



CO_2 compressor

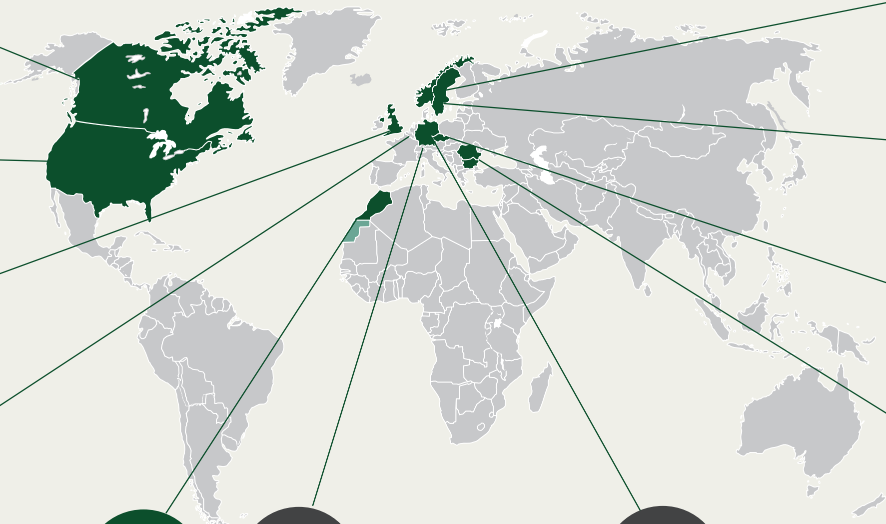
DCC

Capture Brevik Norway

On track....

Brevik CCS experience has spread out over Heidelberg Materials Group

Our mature CCUS projects



CCS 2026
Edmonton, Canada
Capacity: 800 kt CO_2 p.a.
Lehigh Hanson HEIDELBERGCEMENT Group
International CCS Knowledge Centre

CCS
Mitchell, US
Capacity: 2 mt CO_2 p.a.
Lehigh Hanson HEIDELBERGCEMENT Group

CCS 2028
Padeswood, UK
Capacity: 800 kt CO_2 p.a.
HyNet North West

CCUS 2028
Antoing, Belgium
Capacity: 800 kt CO_2 p.a.
Anthemis

CCU 2019
Safi, Morocco
Capacity: 50 t CO_2 p.a.
إسمنت المغرب Ciments du Maroc HEIDELBERGCEMENT Group
Omega Green

CC 2024
Hanover, Germany
LEILAC 1: finalised
LEILAC 2: engineering
Leilac

CC 2024
Mergelstetten, Germany
Oxyfuel demo
catch4climate

CCS 2024
Brevik, Norway
Capacity: 400 kt CO_2 p.a.
BREVIK

CCS 2030
Slite, Sweden
Capacity: 1.8 mt CO_2 p.a.
CEMENTA HEIDELBERGCEMENT Group

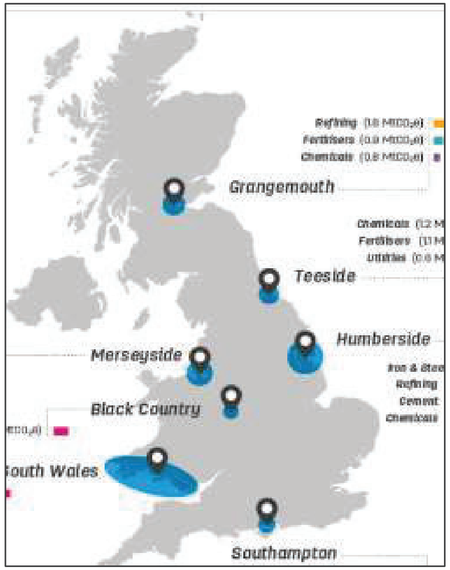
CCS ~2030
Eastern Europe
Two large scale CCS projects

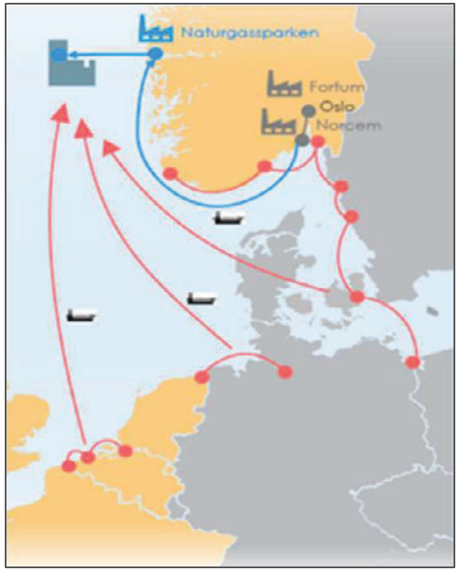
CCUS 2028
Devnya, Bulgaria
Capacity: 800 kt CO_2 p.a.
ANRAV

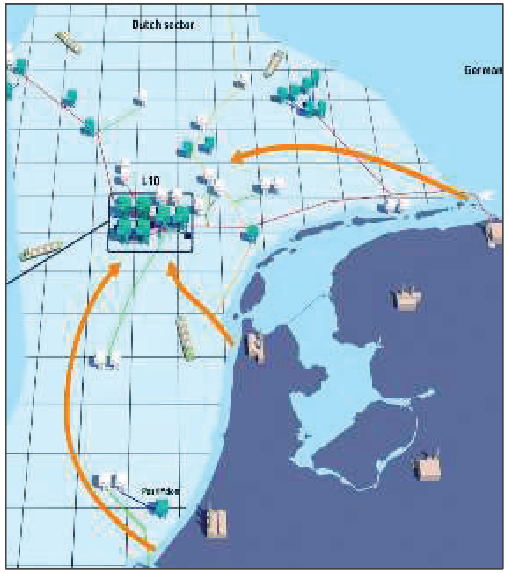
We target to cumulatively capture 10 Mt CO2 by 2030!

ACTUAL

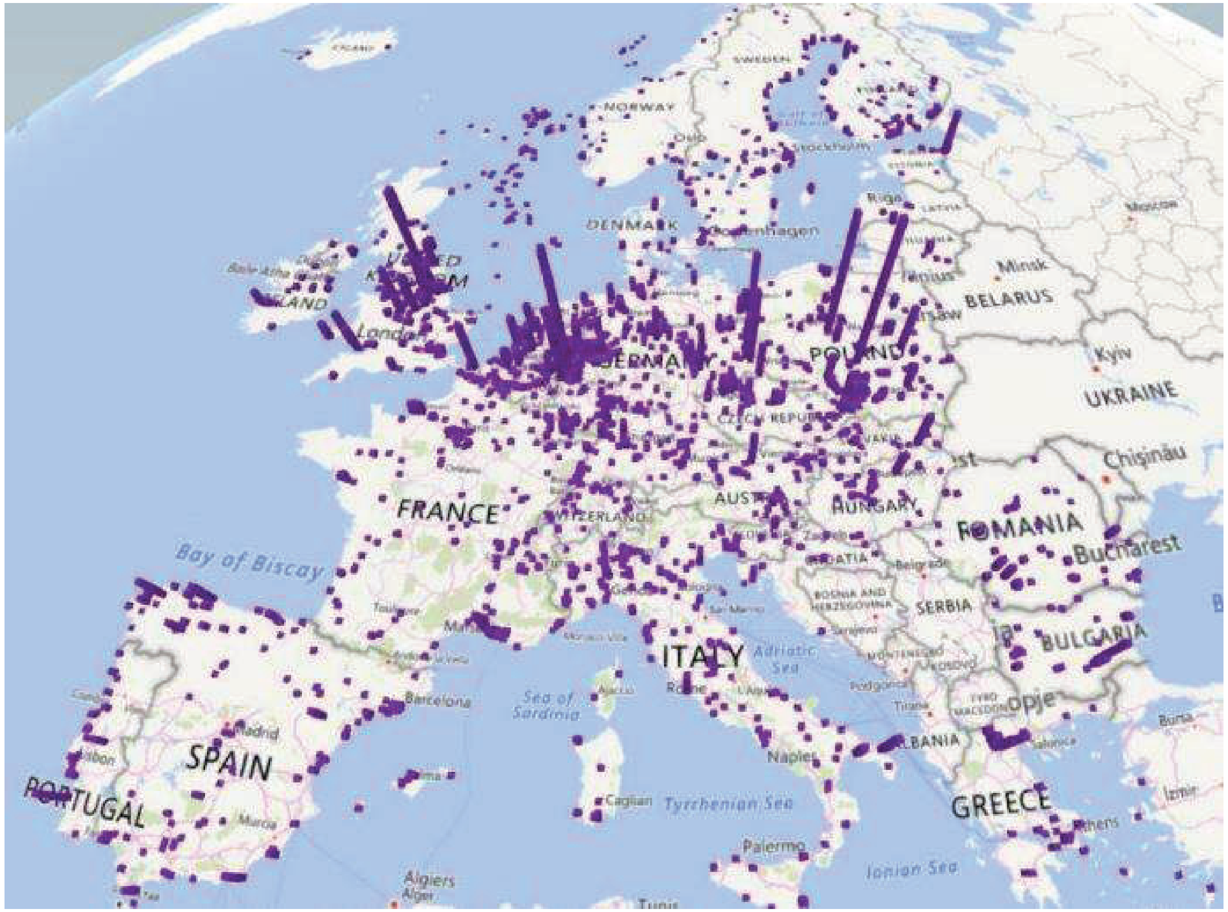
Sofar CCS-clusters in Western Europe all focus on coastal emitters



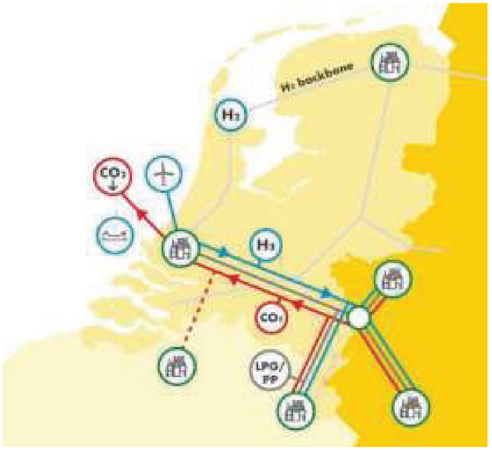


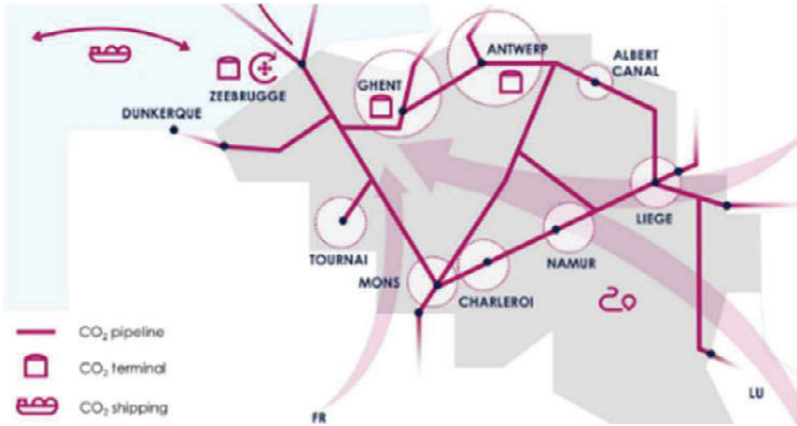


However, the emitters are not only at the coast !

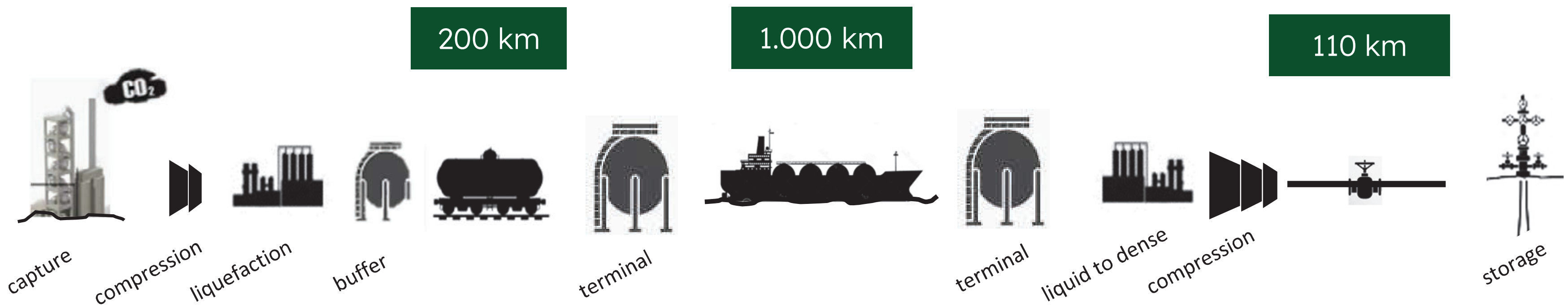


Therefore, we need pipeline infrastructure development to the hinterland and we do see very serious initiatives in NL, Belgium, Germany



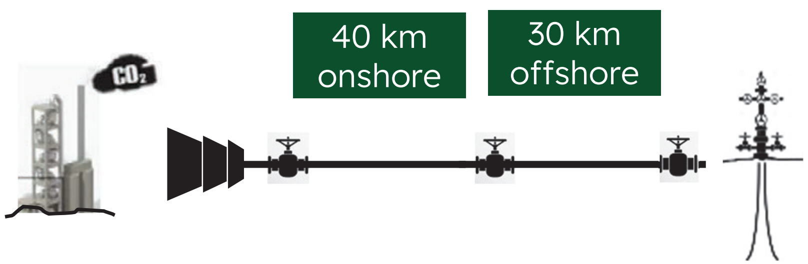


Value-chain has major influence on overall costs of CCS



Compression to storage

>100 €/t CO_2



Compression to storage

< 30 €/t CO_2

Public numbers for full scale capture in the cement industry - Capex (FOAK)

	Capacity	Capex	Accuracy	Year reference for Capex	Capture	Lique-faction	Buffer	Loading
Brevik Norway	0.4 Mt/y	420 m€[1] 340 m€ before Covid and War	90% contracts done	2021	Amine + Waste heat	Yes	5.000 m3	Ship loading
Kujawy Poland	1.2 Mt/y	380 m€[2]	Feasibility study	2021	Cryocap	yes	Yes, for train	Train-loading
Nasice Croatia	0.7 Mt/y	400 m€[3]	Feasibility study	2022	2nd generation oxyfuel (new kiln)	no	no	no
Padeswood UK	0.8 Mt/y	450 m€[4]	Pre-FEED	2022	Amine + CHP	no	no	no
Devnya Bulgaria	0.8 Mt/y	>400 m€[5]	Feasibility study	2021	Oxyfuel + Amine hybrid system	no	no	no

1) Supplerende kvalitetssikring av Langskip – fangst og lagring av CO2, 11. februar 2022

2) https://www.globalcement.com/news/item/15219-eu-awards-euro228m-towards-ccus-upgrade-at-lafarge-poland-s-kujawy-cement-plant

3) https://www.total-croatia-news.com/business/66790-croatian-nexe

4) https://www.padeswoodccs.co.uk/en

5) https://www.globalcement.com/news/item/15201-devnya-cement-and-petroceltic-s-anrav-carbon-capture-project-wins-eu-funding

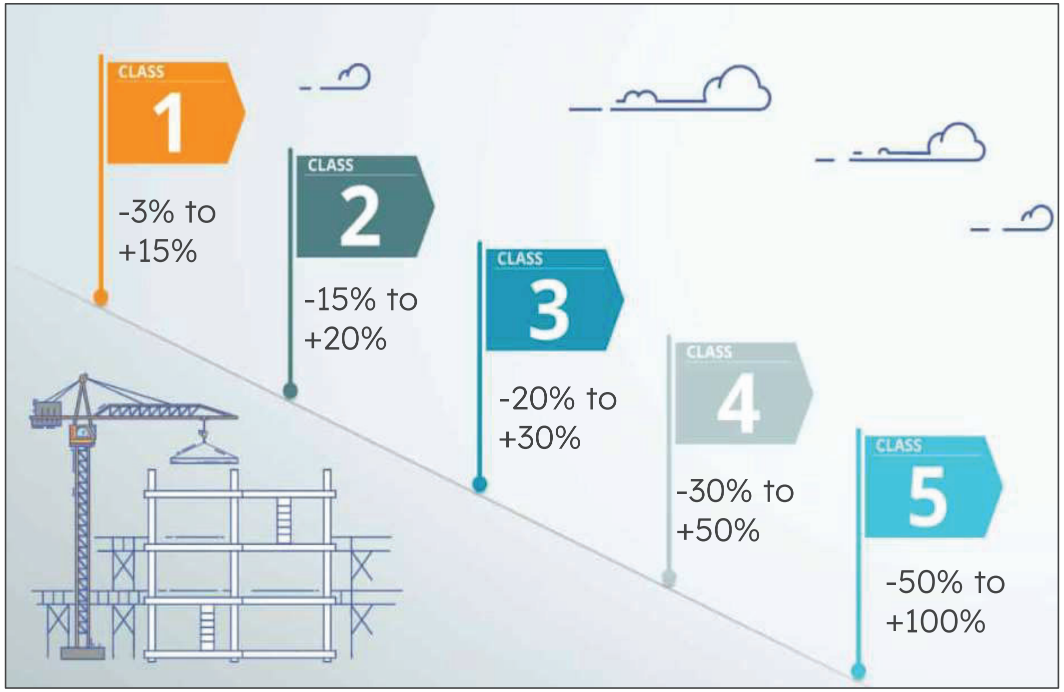
No public info on what is included into the scope:

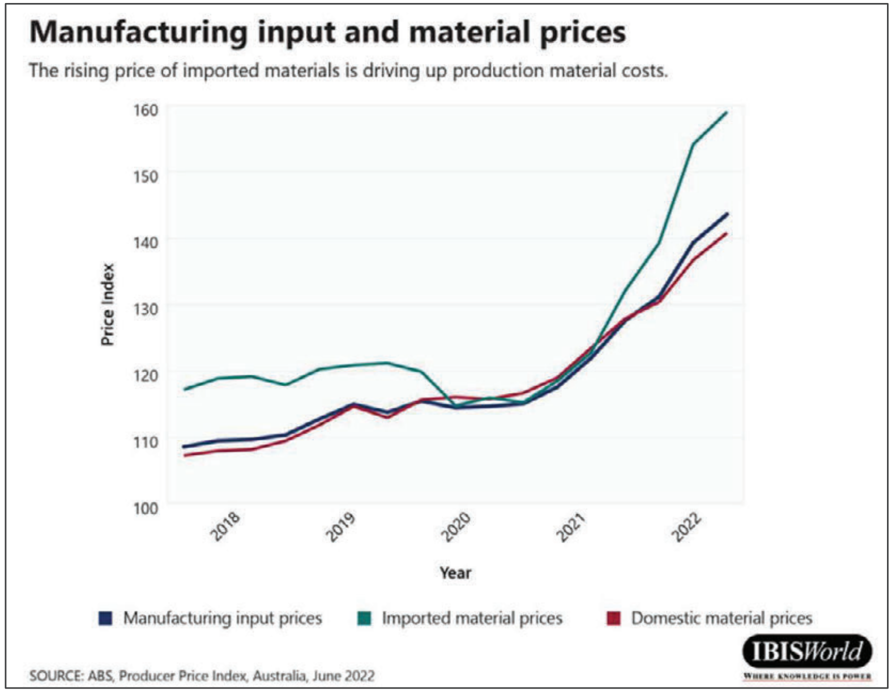
- Dismantling / infra costs
- Upgrade power supply
- DeNox and DeSox units
- Additional AF-feeding units
- Operating hours/year

Overall number

- 3000-4000 tpd clinker line
- Capex ~ 400 M€
- Higher capex → lower opex

Capex – accuracy in different design stages + inflation





OPEX

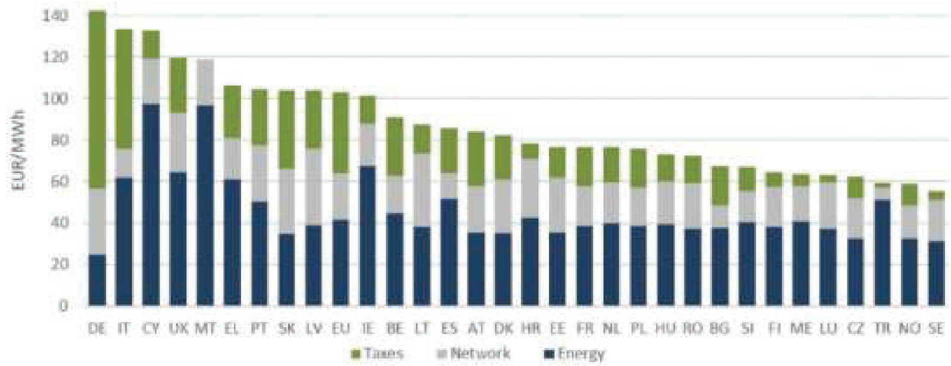
	Heat	Power	Oxygen	Other
Amine	0.7 MW/t CO_2	0.2 MW/t CO_2	n.a.	10-15 €/t CO_2
Cryocap	-	0.4 MW/t CO_2	n.a.	10-15 €/t CO_2
2nd gen oxyfuel	-	0.15 MW/t CO_2	0.35 t O_2/t CO_2	10-15 €/t CO_2
OxyCal + Amine	-	0.2 MW/t CO_2	0.3 t O_2/t CO_2	10-15 €/t CO_2

	Heat
Waste heat	Capex dominated
CHP	Cost of fuel
RDF based CHP	RDF-price + Capex
Heat pump	Capex dominated

	Oxygen
ASU at site	Capex + Power price
Supply market	Logistics – power price
By-product green H2	Power price

OPEX – dominated by cost heat and power (depending on capture technology)

2017 – comparison €/MWh in EU countries



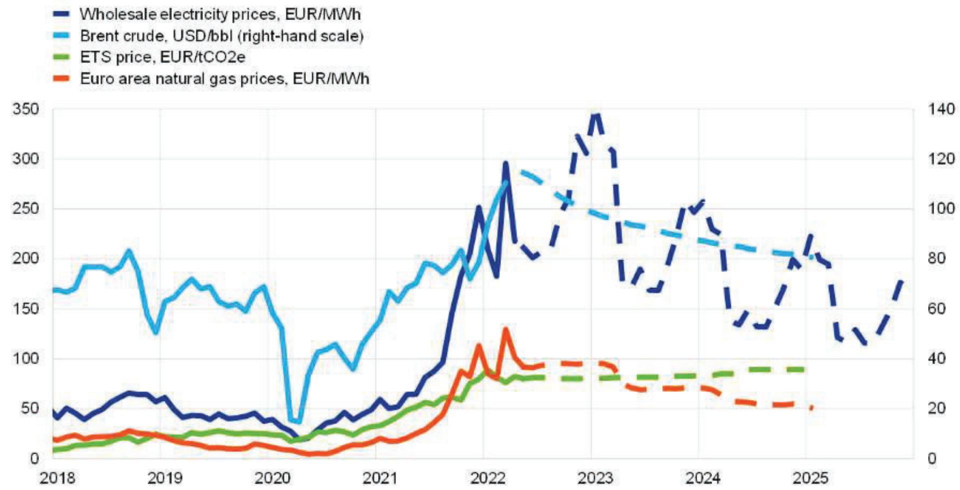
Industry power prices in the EU. Source Eurostat/DG ENER

Variation from 58 to 140 €/MWh

Chart 1

Pandemic-related drop in energy prices followed by substantial price increases

(left-hand scale: EUR per unit; right-hand scale: USD per unit, monthly average values)



Sources: Eurostat, Refinitiv and ECB staff calculations.

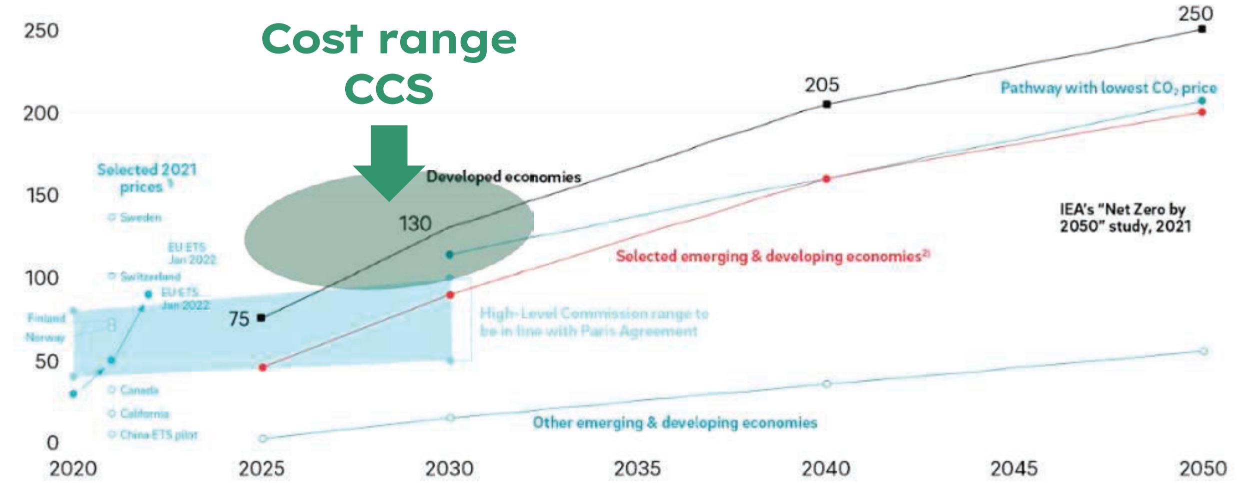
Costs of CCS value-chain in Europe for cement industry; operational 2026 - 2030

When EU ETS prices equals to CCS costs per ton CO_2

project still NOT profitable without funding support

(at least 3 years before savings arrive, considerable Capex needs to be spent)

Current carbon prices and future carbon price scenarios [USD/ton of CO2]



1) Based on World Bank data – Highest available price per country displayed
2) Including China, Russia, Brazil and South Africa

Source High-Level Commission, IEA, IPCC, I4CE, World Bank, Roland Berger

Roland Berger

CCUS

Key take aways

- CCS cost of full value-chain dominated by:
  - Geographical location
  - Costs for heat and/or electricity

- Within Europe the CCS-projects without funding support do not have a positive business case

- CO_2-infrastructure development key for using full potential of CCS for cement industry

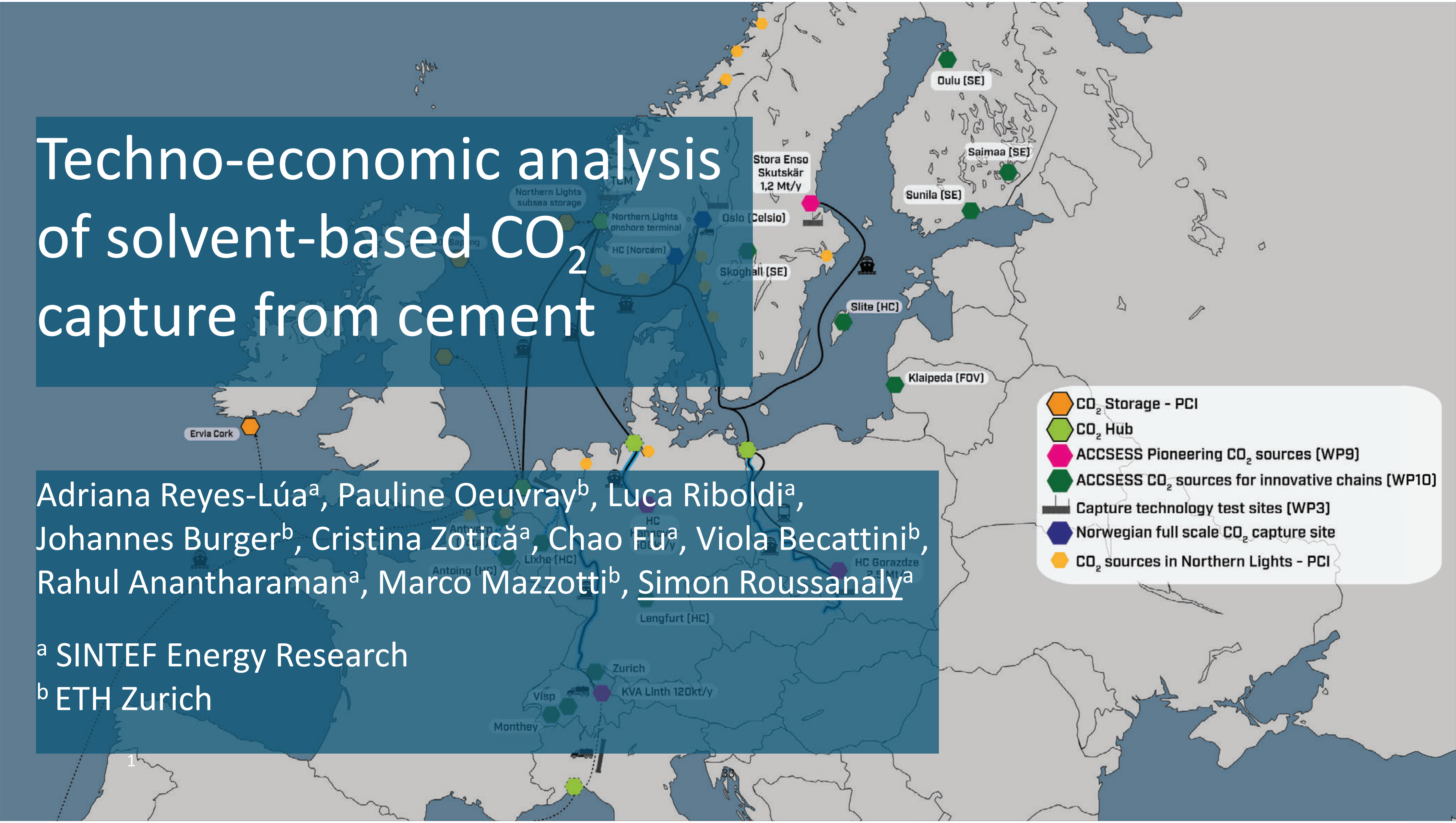
1.2. Techno-economic analysis of solvent-based CO_2 capture from cement

Simon Roussanaly (SINTEF)

Techno-economic analysis of solvent-based CO_2 capture from cement

Adriana Reyes-Lúa[a], Pauline Oeuvray[b], Luca Riboldi[a], Johannes Burger[b], Cristina Zotică[a], Chao Fu[a], Viola Becattini[b], Rahul Anantharaman[a], Marco Mazzotti[b], Simon Roussanaly[a]

[a] SINTEF Energy Research
[b] ETH Zurich



ACCSESS

Providing access to cost-efficient, replicable, safe, and flexible CCUS

Horizon2020 Innovation Action

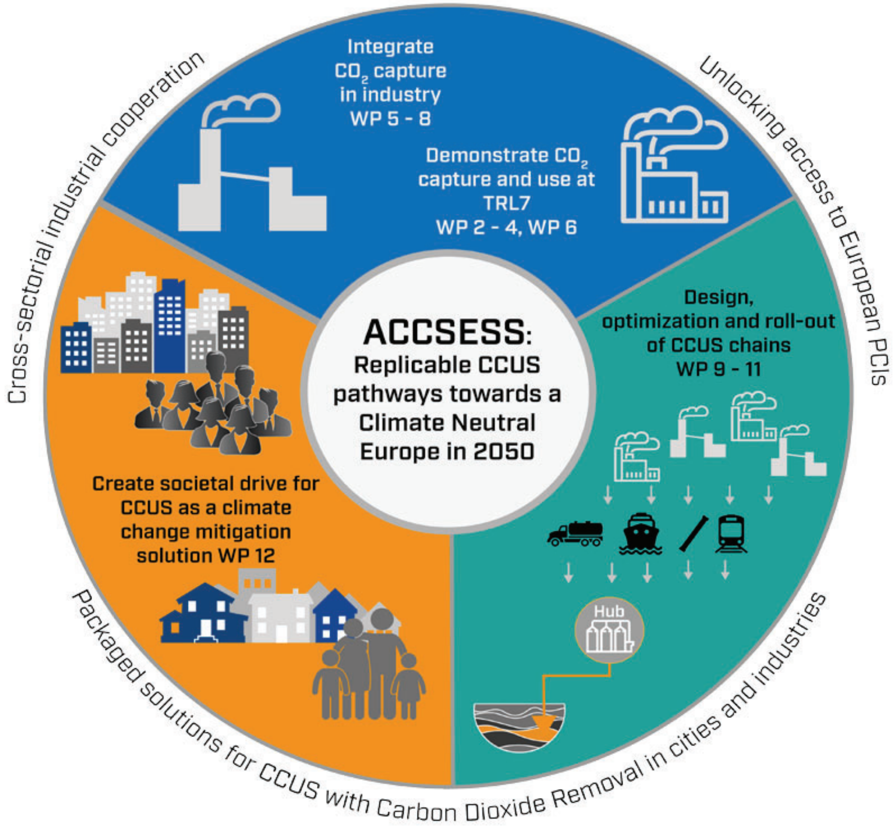
Duration: May 2021- April 2025

Coordinator: SINTEF Energy

Budget: 18.4 MEUR, EU funding 15.0 MEUR

Main objectives

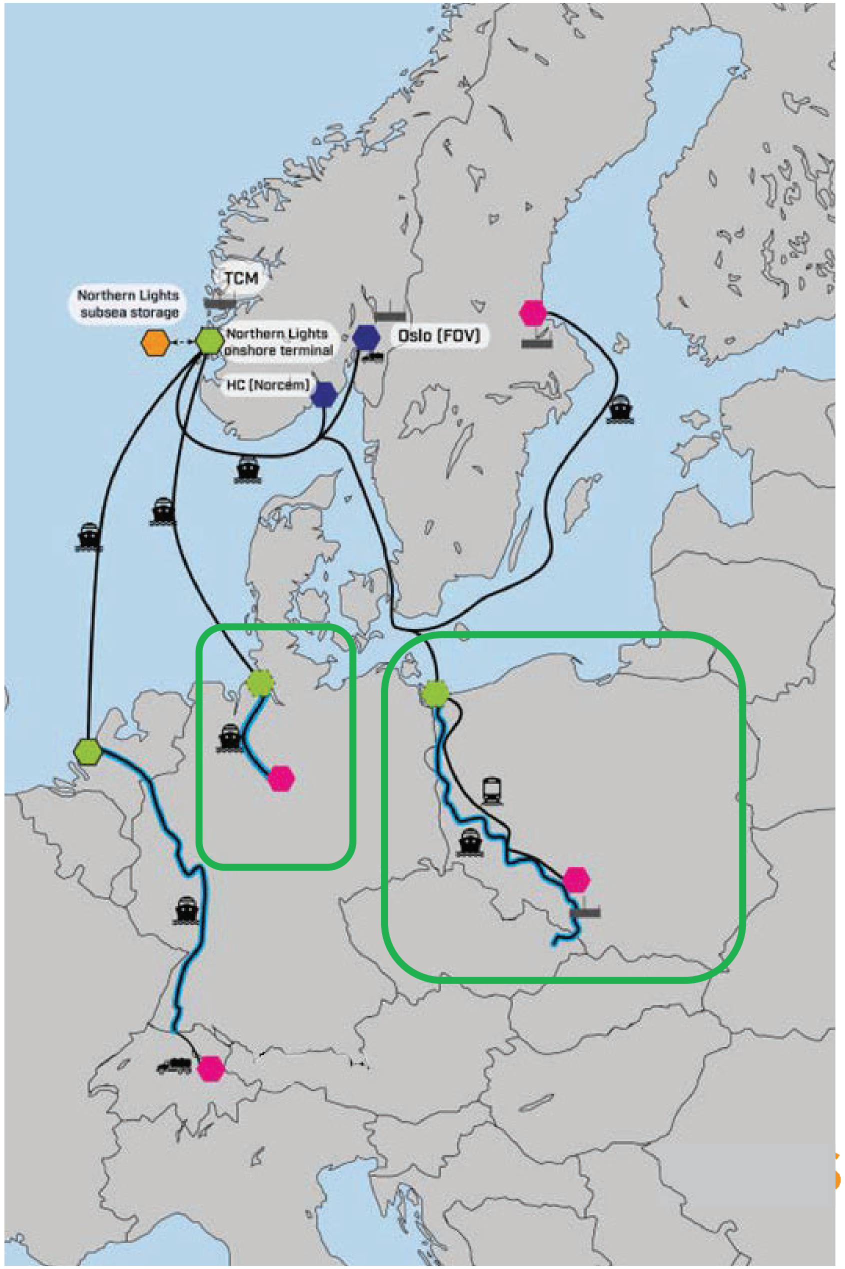
- **Capture: Demonstrate CO_2 capture and use in industry; integrate capture technologies industry**
- **Chains: Develop and improve CCUS chains from continental Europe and the Baltic area to the North Sea**
- **Society: Engage and inform stakeholders about CCUS and explain its societal benefits at large and for sustainable cities**



ACCSESS

Pioneering chains

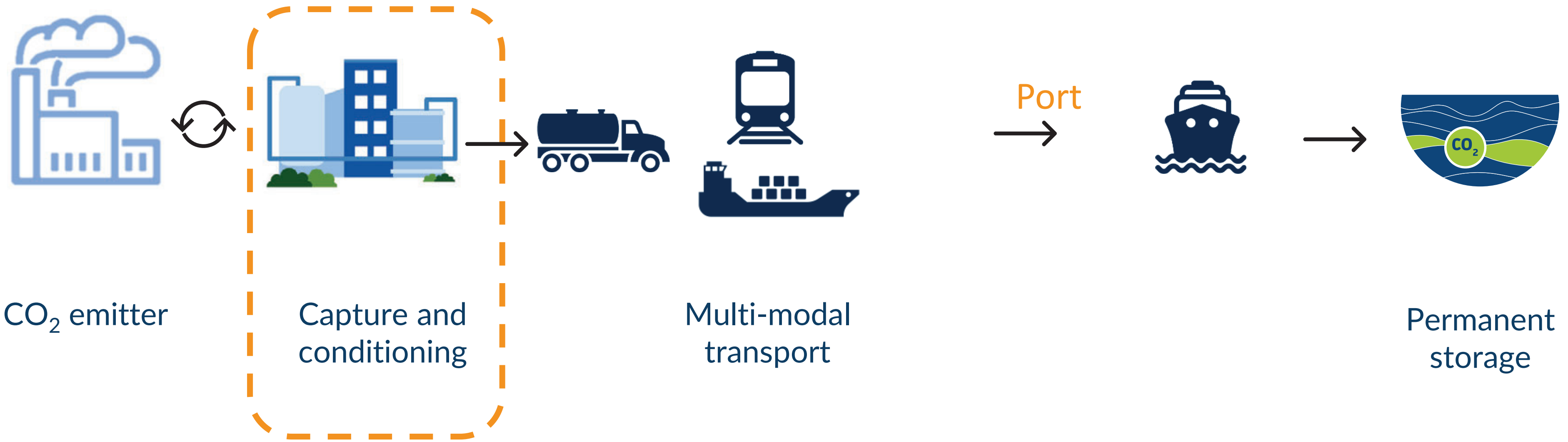
- Four reference industrial plants in ACCSESS
  - Cement plant in Germany
  - Cement plant in Poland
  - Pulp mill in Sweden
  - Waste-to-energy plant in Switzerland



Key characteristics

Location	Northern GE	Southwest PL
Clinker capacity (t/d)	2500	12000
CO_2 captured (Mt/y)	0.62	1.58
Flue gas flow rate (Nm^3/h)	304205	632000
Pressure (bara)	0.98	1.01
Temperature (°C)	125	Up to 163
Gas composition , wet basis (%mol)		
CO_2	15.1	17.8
N_2	59.6	53.7
O_2	12.1	10.6

System boundaries of the presentation



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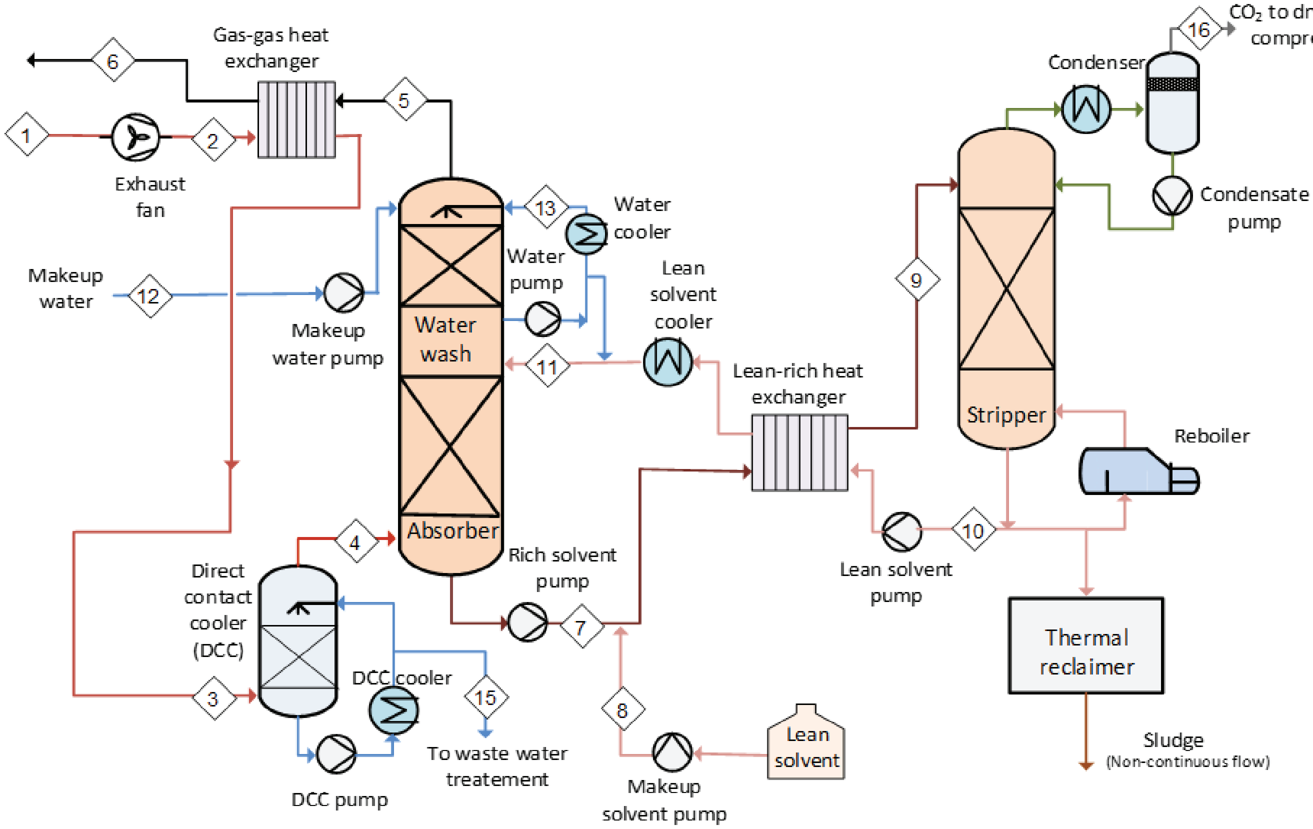
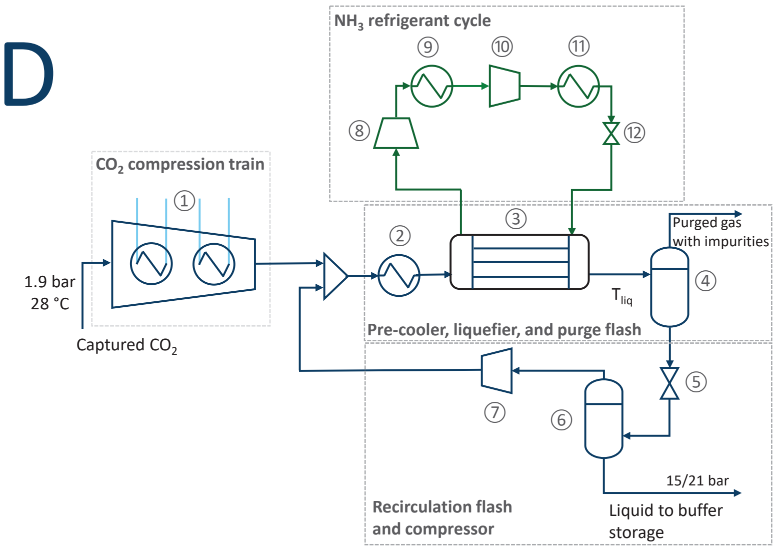
CO_2 capture and conditioning PFD



Fu et al. 2019



Deng et al. 2019

Design basis/Main assumptions

- Simulations
  - Industrial flue gas
  - 90% capture rate
  - AMP/PZ solvent
  - 15 barg liquid CO_2
- First of a kind (FOAK) evaluation
- Steam from biogas/biomass
- CO_2 emissions from utilities
- Cost basis 2019

FOAK TEA assessment has been based on Roussanaly et al. 2021 Toward improved guideline for cost evaluation of CCS

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FOAK assessment

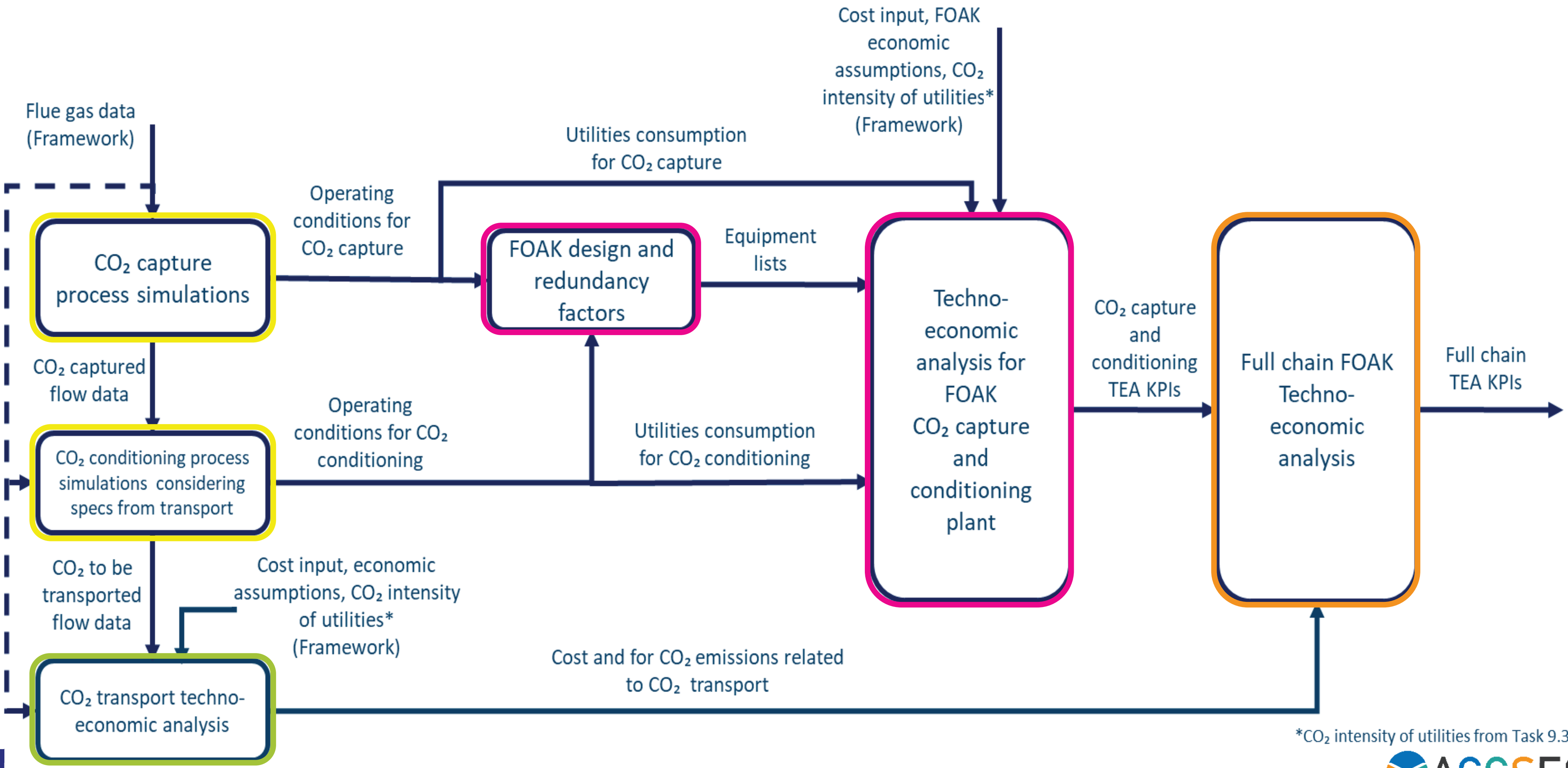
Towards improved guidelines for cost evaluation of carbon capture and storage

A white paper prepared by

Simon Roussanaly[a,*], Edward S. Rubin[b], Mijndert van der Spek[c], George Booras[d], Niels Berghout[e], Tim Fout[f], Monica Garcia[g], Stefania Gardarsdottir[a], Vishalini Nair Kuncheekanna[h], Michael Matuszewski[i], Sean McCoy[j], Joshua Morgan[i], Shareq Mohd Nazir[k], Andrea Ramirez[l]

- **Increased CAPEX**
  - Oversized design, additional spare and redundant equipment
  - Higher process contingencies
  - Higher system contingencies
  - Stricter material selection and design standards
  - Higher escalation cost during planning and construction
  - Higher discount rate to reflect risk premium
- **Increased OPEX**
  - More training required for technicians, plant operators and plant engineers
  - Slower ramp-up to design operation
  - Higher fixed cost due to the higher CAPEX

Workflow

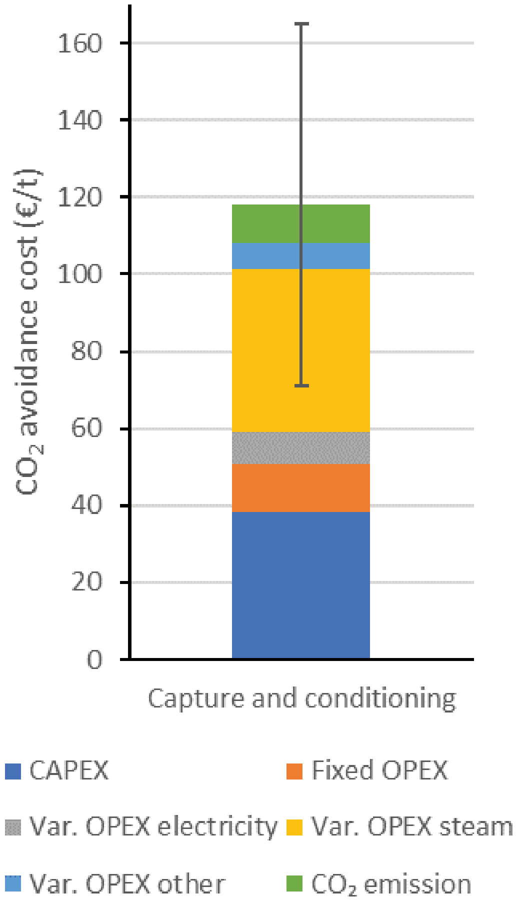


*CO_2 intensity of utilities from Task 9.3

Cost results for the German case

CO_2 capture and conditioning only

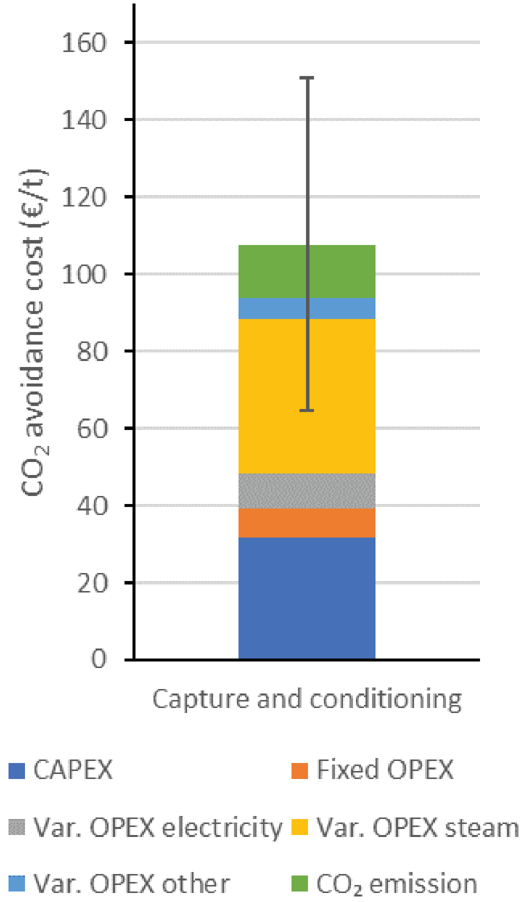
- Cost
  - CAPEX ~ 180 M€
  - NPV of non-energy OPEX ~ 90 M€
  - NPV of energy OPEX ~ 242 M€
- CO_2 avoidance cost for the capture and conditioning sections ~ 118 €/t (+/- 40%)
- Main contributors:
  - CAPEX ~ 32%
  - Steam ~ 36%



Cost results for the Polish case

CO_2 capture and conditioning only

- Cost
  - CAPEX ~ 750 M€
  - NPV of non-energy OPEX ~ 155 M€/y
  - NPV of energy OPEX ~ 600 M€/y
- CO_2 avoidance cost for the capture and conditioning sections ~ 108 €/t (+/- 40%)
- Main contributors:
  - CAPEX ~ 30%
  - Steam ~ 37%



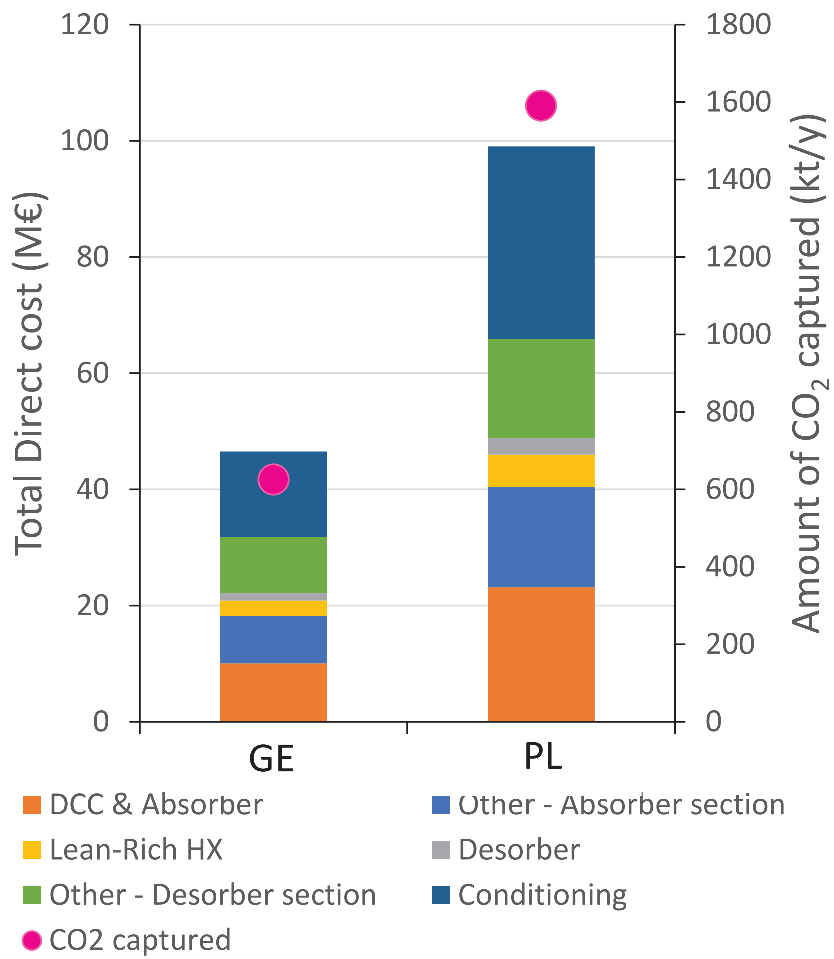
TDC breakdown

- Absorber section ~ 38-40%
  - DCC and absorber ~ 22%

- Desorber section ~ 25-30%
  - Desorber ~ 3%
  - Lean-Rich HX ~ 5%

- Conditioning ~32%

CO_2 capture and conditioning only



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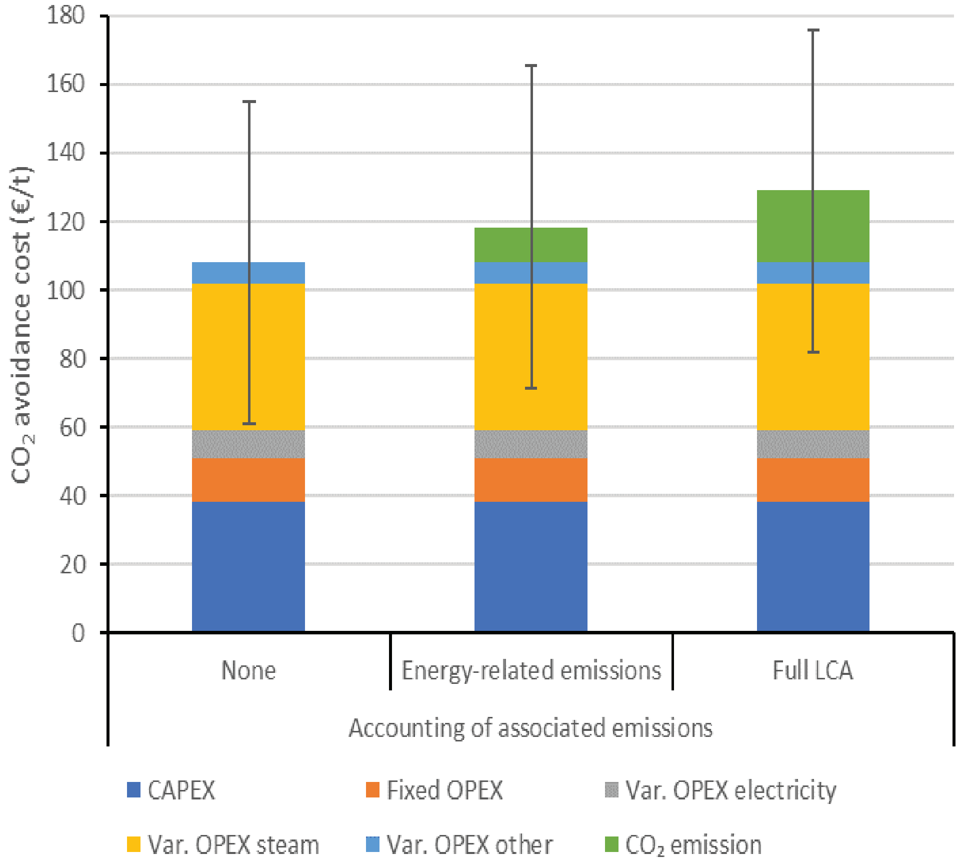
Impact of associated CO_2 emissions

CO_2 capture and conditioning only

- Inclusion of emissions associated with CO_2 capture and conditioning (German case)
  - "Energy-only" related emissions lead to an avoidance cost increase of ~10%
  - Emissions from a full LCA evaluation lead to an avoidance cost increase of ~20%
  - Emissions impact here is "low" as biogas is used to produce the steam required by the capture



Toward improved CCUS chains

- Cost of FOAK of CO_2 capture and conditioning 80-120 €/tCO_2 (4 pioneering cases) and between **100 and 280 €/t_{CO_2}** once transport to harbour is included (very case specific)
  - Possibility to reduce costs in CO_2 capture with advanced/novel technologies and heat integration
  - Possibility to reduce CO_2 transport cost with advanced technologies and clustering options
  - Possibility to reduce CCS chain cost by considering different storage locations and utilization options
  - Cost will be reduced as more and more projects are deployed (from FOAK to NOAK chains)

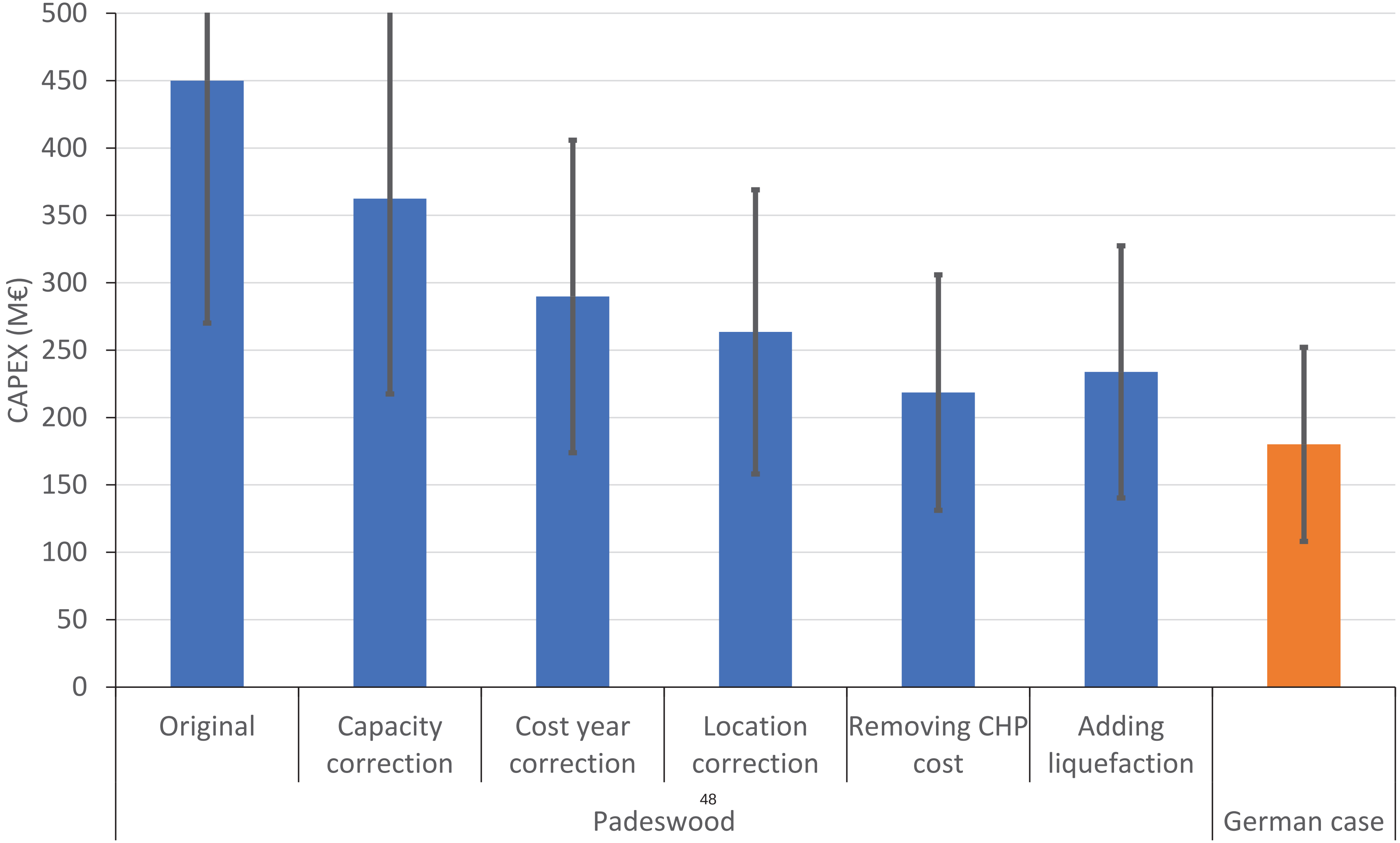
- The CCTS chains considered can already now avoid **75% to 89%** of the industrial emissions. Further improvements possible:
  - Higher capture rates
  - Decarbonization of the grid mix
  - Decarbonization of CO_2 transport

Lessons learned and reflections

- The work offers novel learnings:
  - The cost of rolling-out pioneering CCS chains from inland European emitters
  - The economic burden to be early movers (cost of FOAK vs NOAK)
  - The importance to develop economically feasible inland CO_2 transport solutions and inland CO_2 storage options

- The work also inspires important reflections for upcoming projects:
  - How to enable implementation of Pioneering CCS chains (despite the potential high costs)?
  - What opportunities are there to reduce the cost in the near-term?
  - What opportunities are there to increase the emissions avoidance?

Comparison of CAPEX with public numbers



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Acknowledgement

This project has received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 101022487

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Session 2: FEED Studies

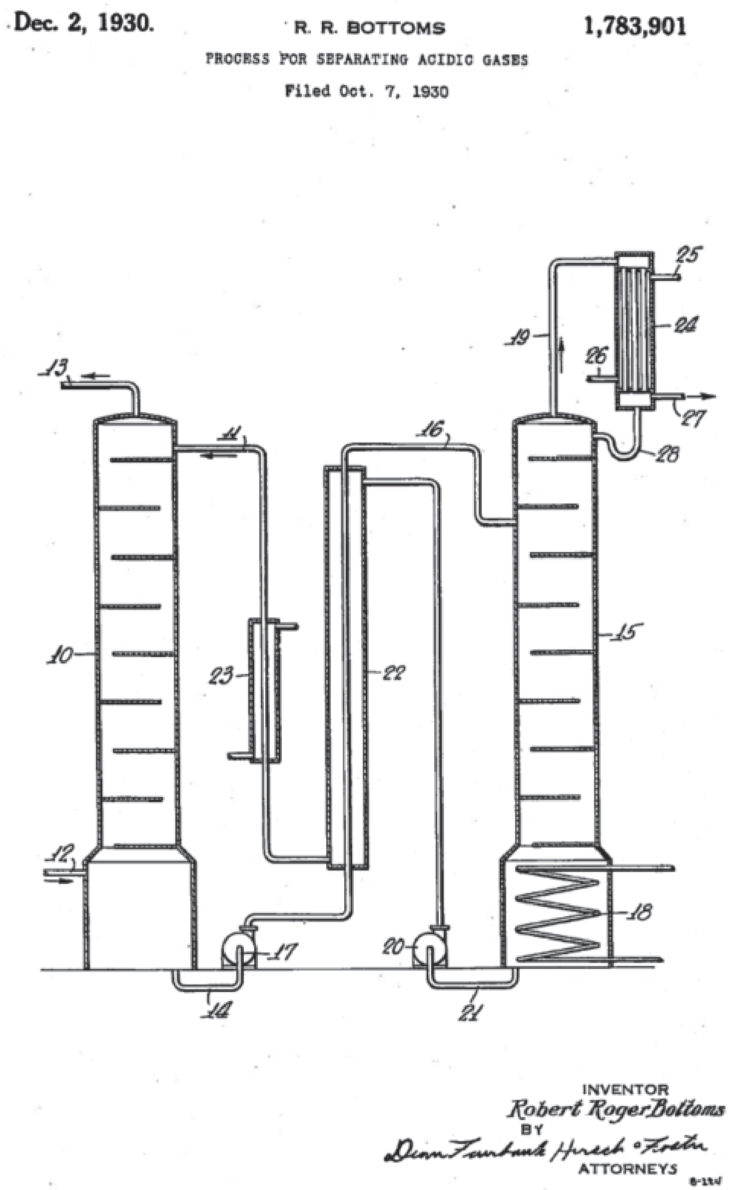
2.1. The cost of carbon capture plants; say it ain’t so, Joe

-
Bill Elliot (Bechtel)

The Cost of Carbon Capture Plants; *say it ain't so, Joe*

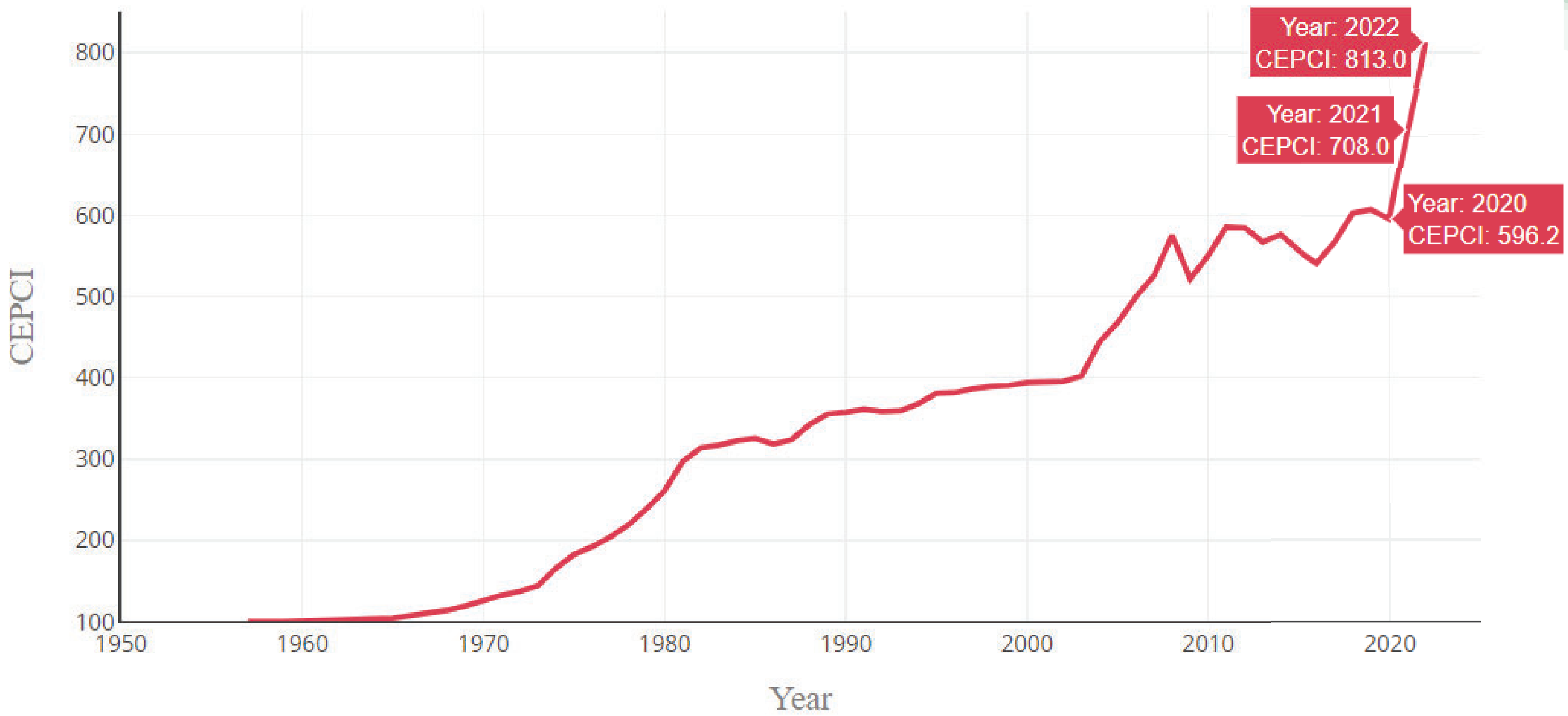
Bill Elliott

Bechtel Corporation



The Chemical Engineering Plant Cost Index (CEPCI)

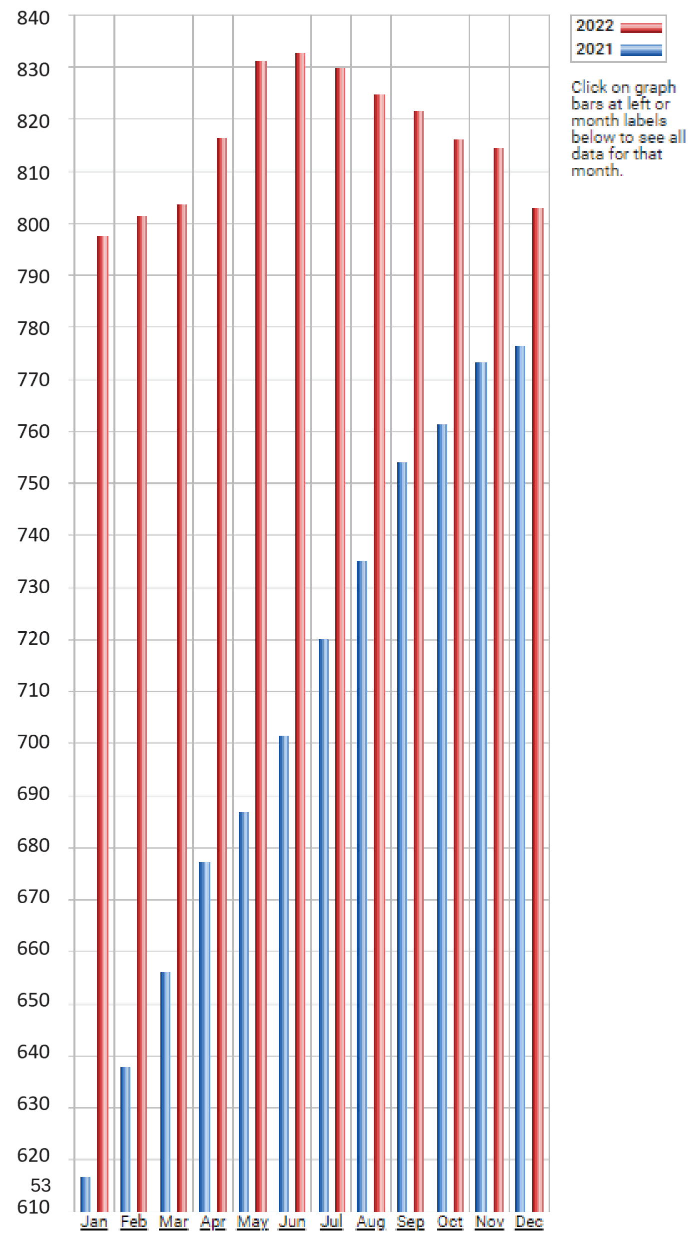
- Composite index from four sub-indexes:
  - ✓ Equipment
  - ✓ Construction Labor
  - ✓ Buildings
  - ✓ Engineering & Supervision



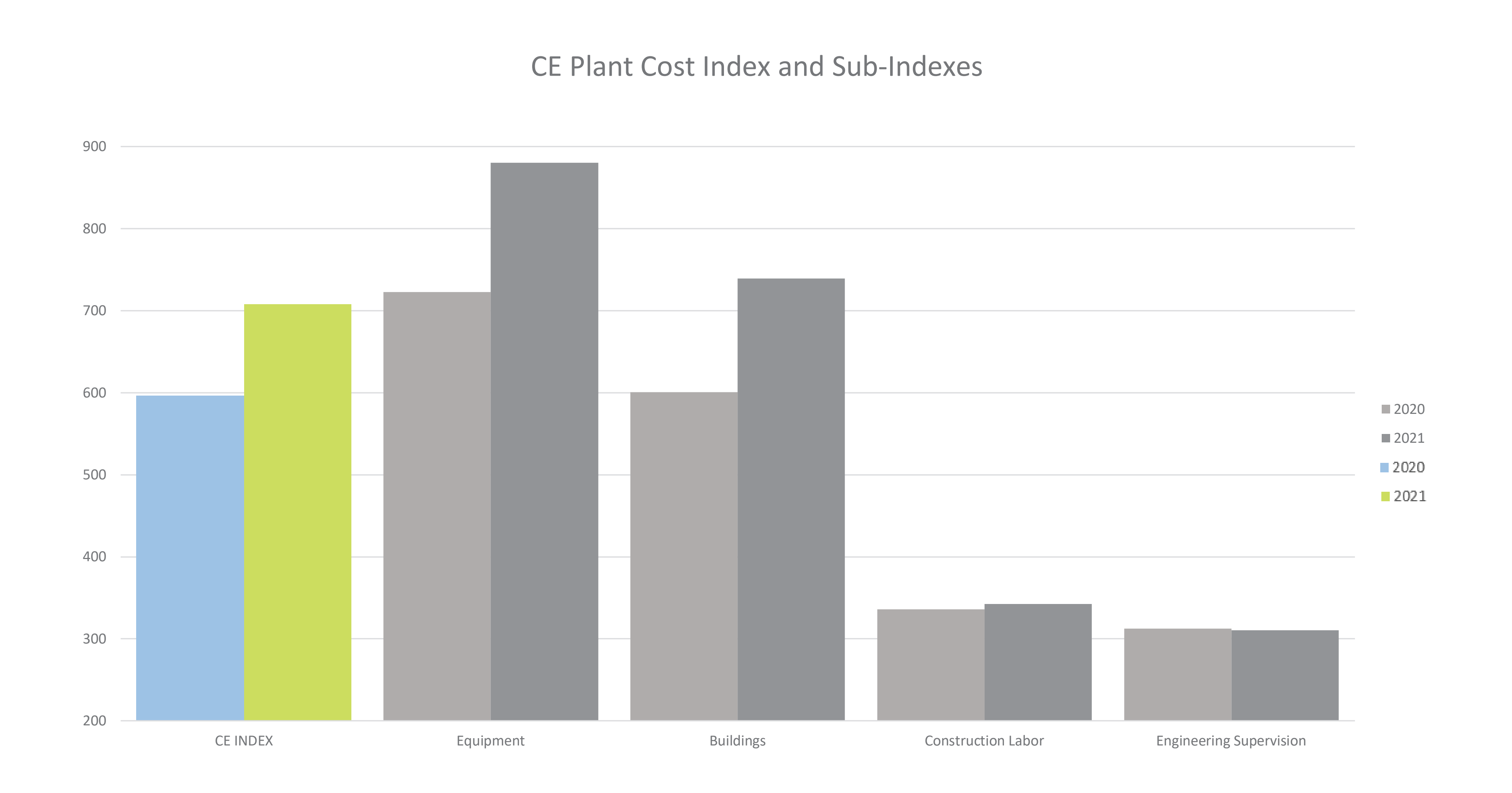
Graph: The University of Manchester, Department of Chemical Engineering;
Data: The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com

The Chemical Engineering Plant Cost Index

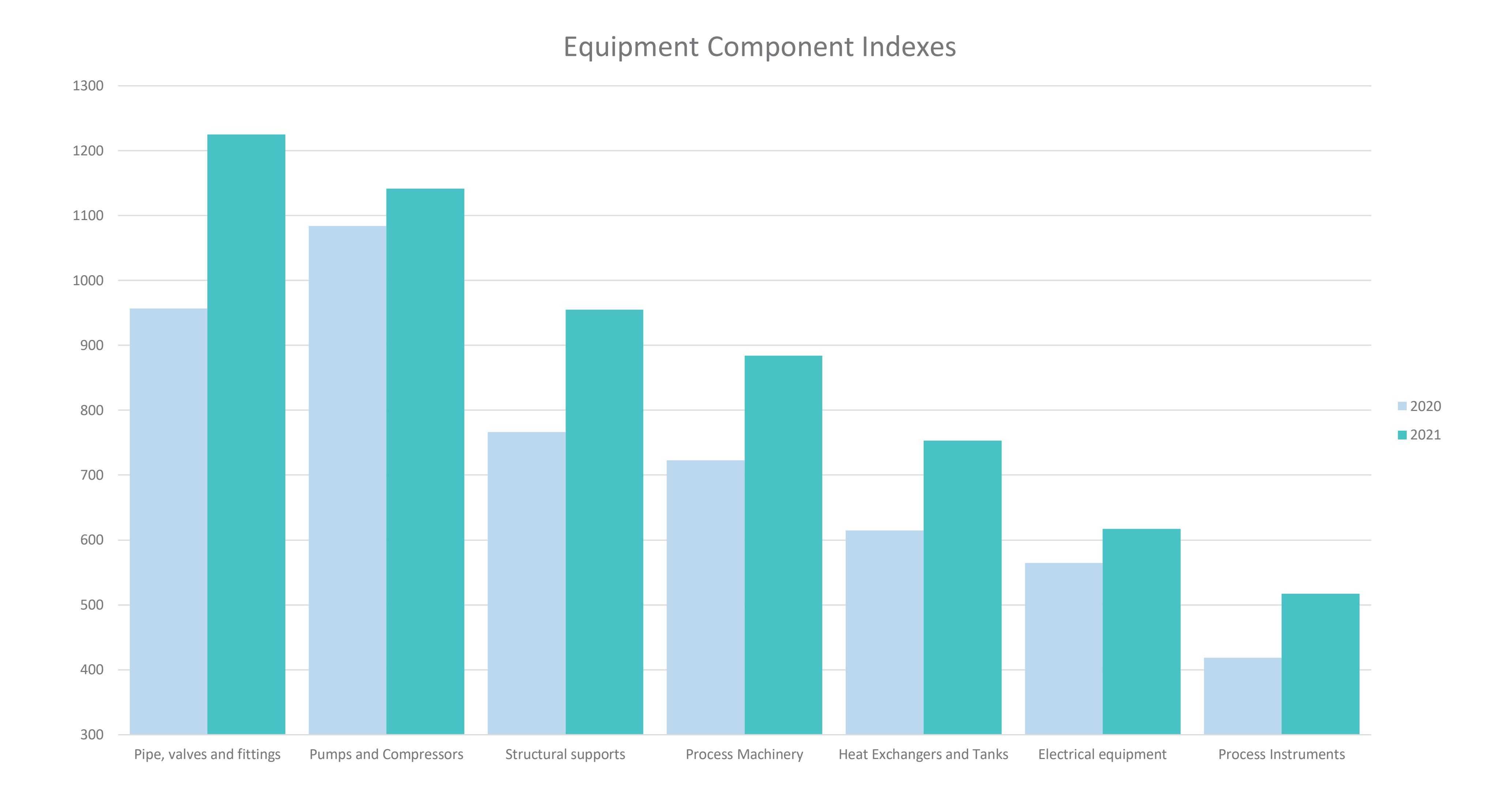
2021 vs 2022



The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com



Data: The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com



Data: The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com

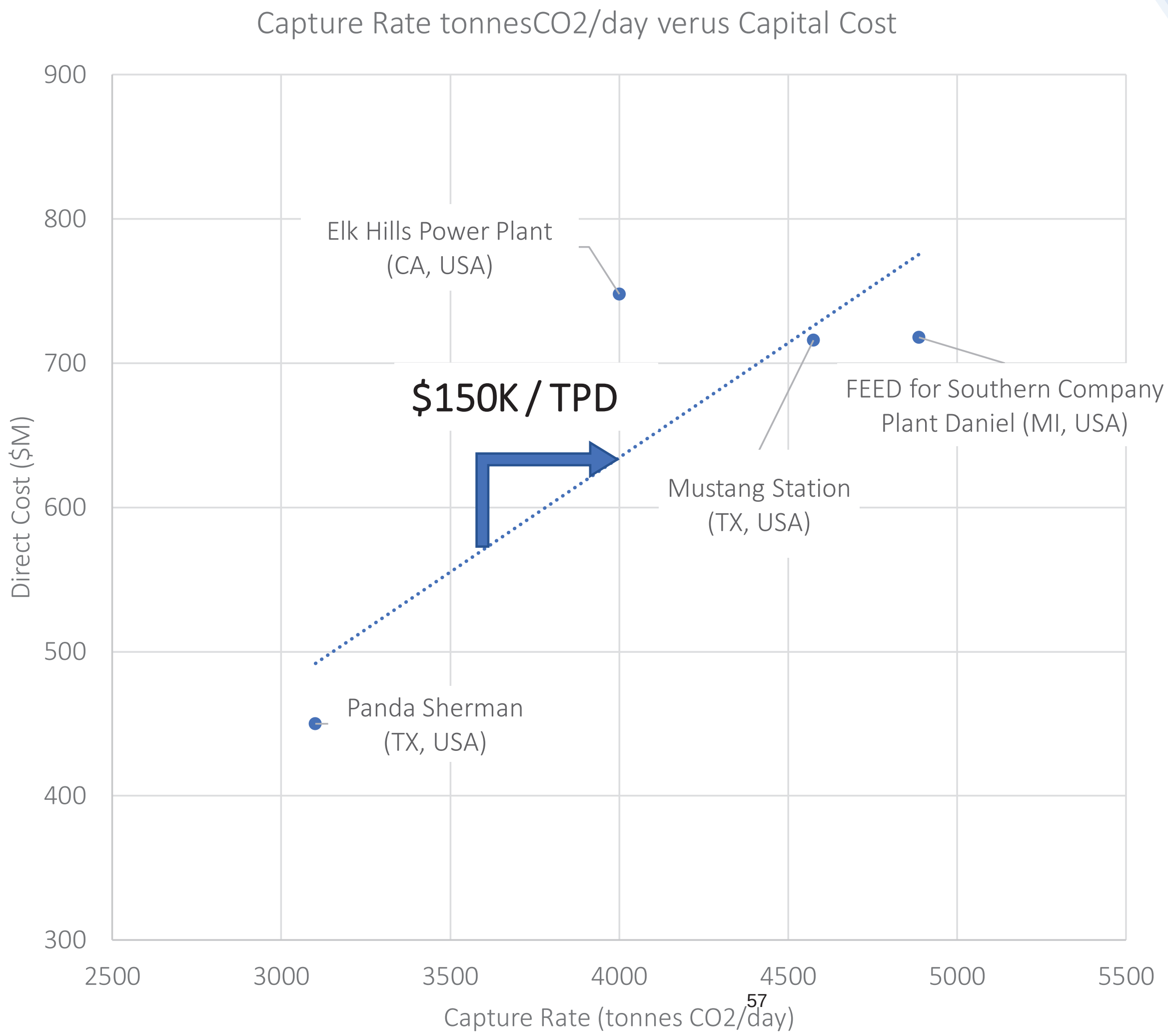
The Chemical Engineering Plant Cost Index

2022 vs 2023

	Jan '23 Prelim.	Dec '22 Final	Jan '22 Final
CE INDEX	801.4	802.9	797.6
Equipment	1,015.6	1,016.1	1,009.2
Heat Exchangers and Tanks	832.7	840.8	860.3
Process Machinery	1,030.4	1,031.4	993.1
Pipe, valves and fittings	1,426.8	1,427.2	1,457.0
Process Instruments	561.4	558.5	568.9
Pumps and Compressors	1,389.1	1,332.4	1,213.2
Electrical equipment	797.3	790.7	698.9
Structural supports	1,113.7	1,122.5	1,115.5
Construction Labor	357.7	359.0	345.6
Buildings	795.6	794.2	831.3
Engineering Supervision	301.2	311.8	310.7

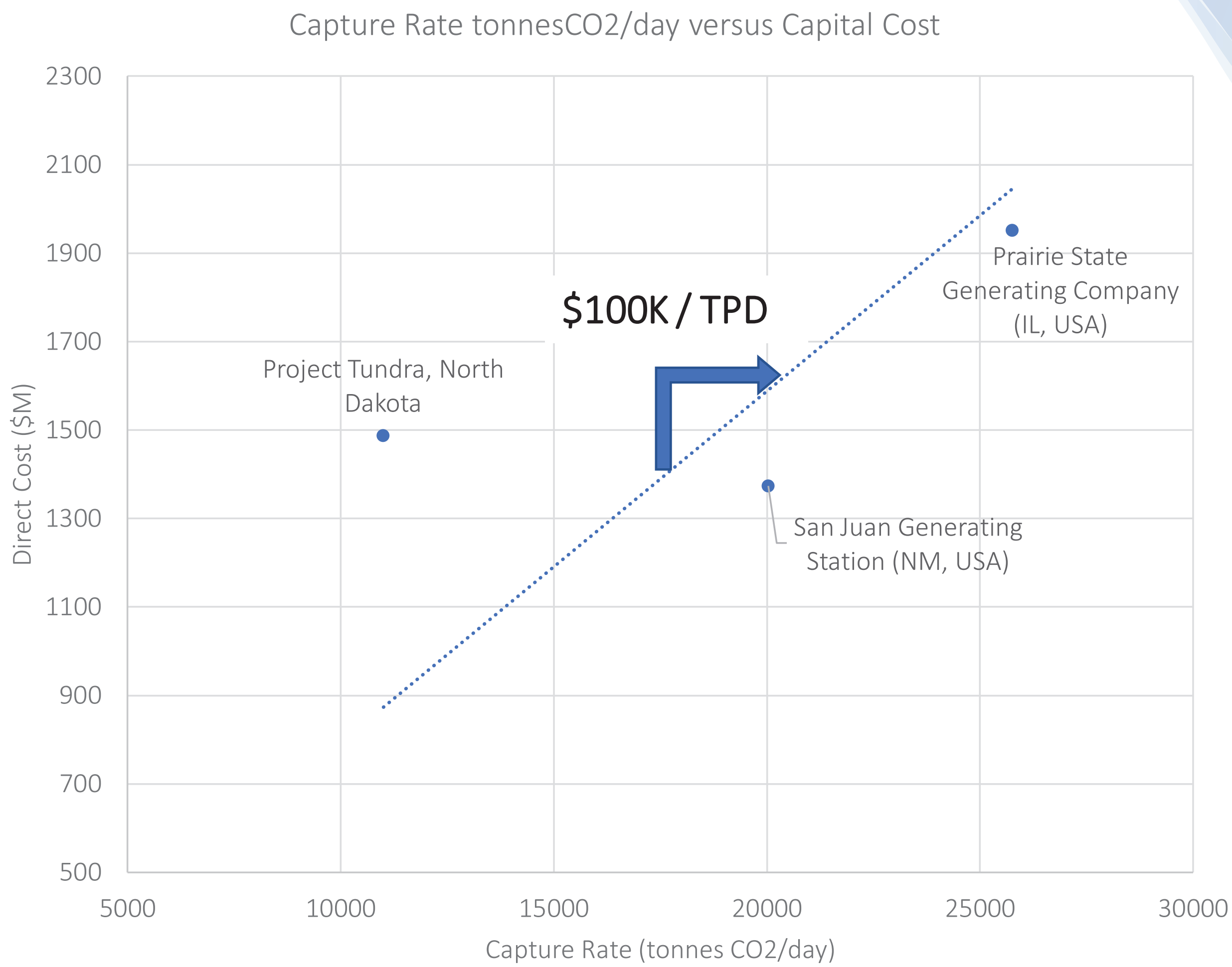
The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com

NGCC Plants - Capture Rate tonnesCO2/day versus Capital Cost



**Costs & Capture Rates are approximations*

Solid Fuel Plants - Capture Rate tonnesCO2/day versus Capital Cost



*Costs & Capture Rates are approximations

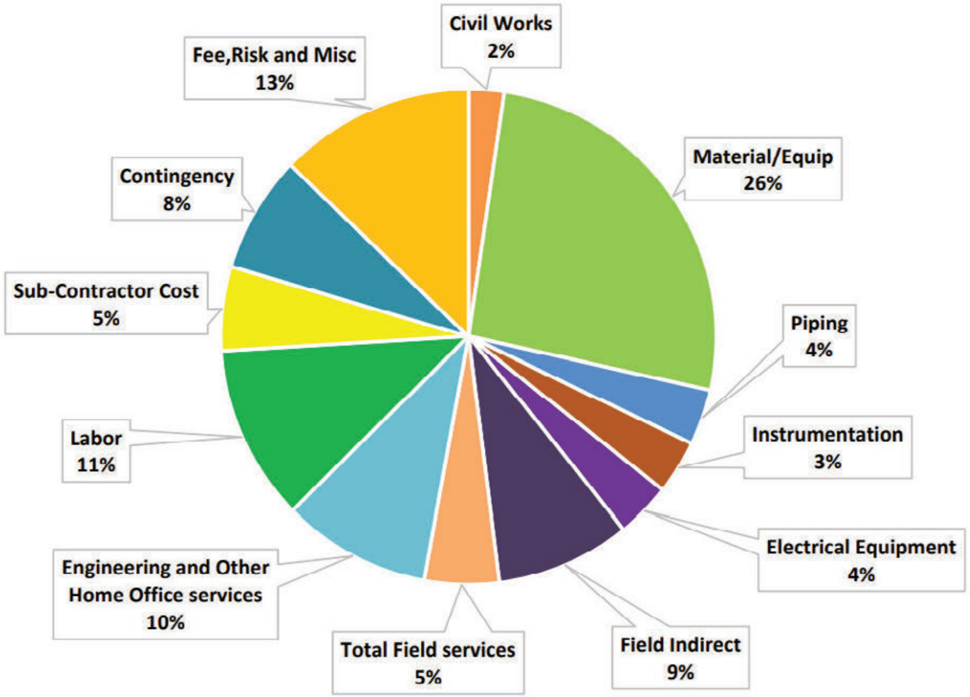
Sherman, TX NGCC Post Combustion Capture Plant

Cost Sensitivities and Uncertainty Levels Tornado Diagram

% Range	$/Tonne CO2 Captured		Base ($/Tonne CO2 Captured)
Cap Cost ± 15%	12.5	12.5	83.10
Maintenance ± 50%	3.5	3.5	7.00
Energy ±20%	2.6	2.6	13.00
Personnel ± 30%	1.9	1.9	6.20
Solvent ± 50%	1.2	1.2	2.30
Other Ops ± 50%	0.8	0.8	1.55
Waste Disposal ± 50%	0.7	0.7	1.35

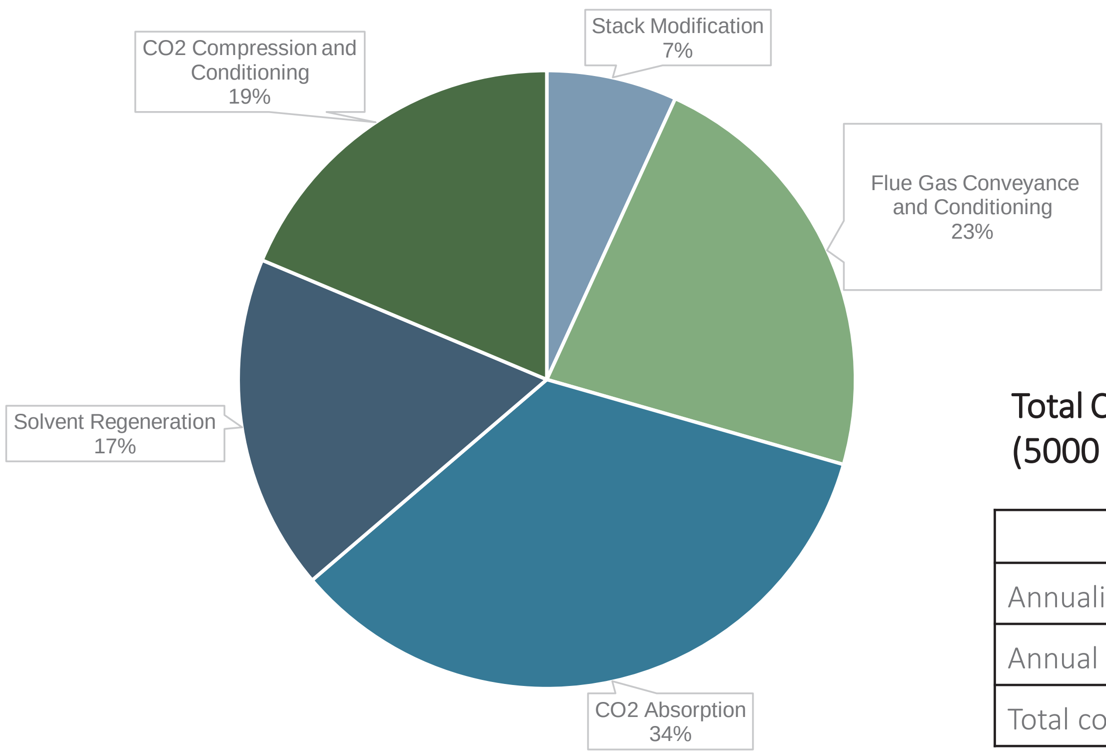
Sherman, TX NGCC Post Combustion Capture Plant

Cost for PCC Areas as Percent of Contractor's Cost



Sherman, TX NGCC Post Combustion Capture Plant

Cost as Percentage of Contractor's Cost

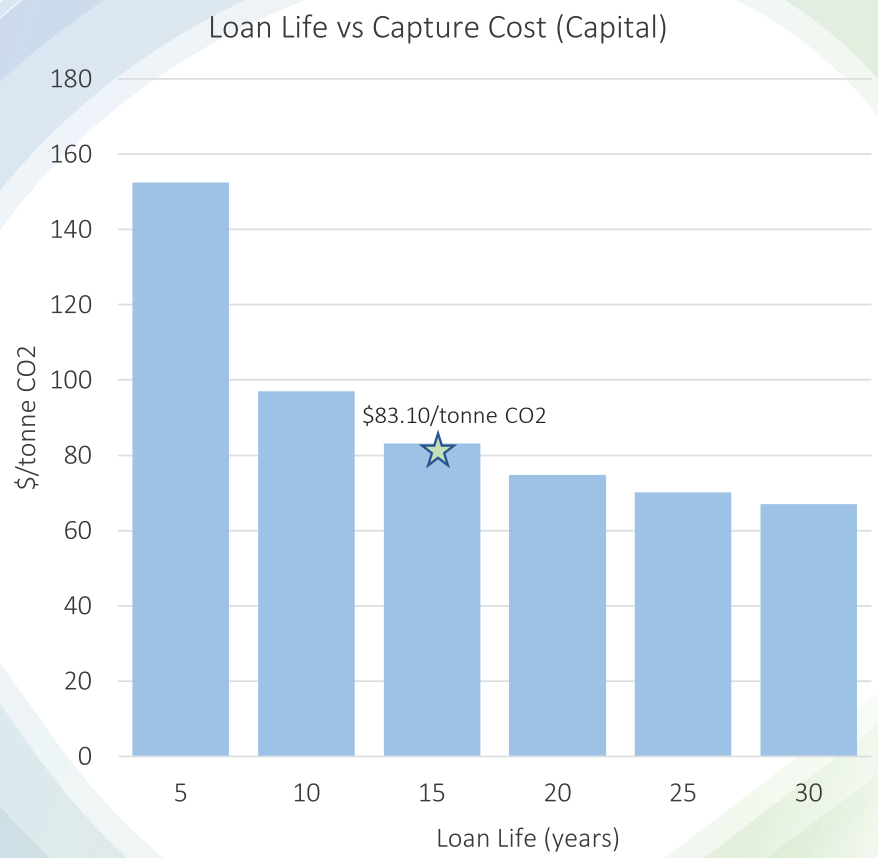


Total Cost per Tonne CO_2 Captured (5000 hrs per year basis)

	\$/Tonne CO_2
Annualized capital cost	83.10
Annual O&M cost	31.40
Total cost per tonne CO_2	114.50

Effect of Loan Life on Capture Cost

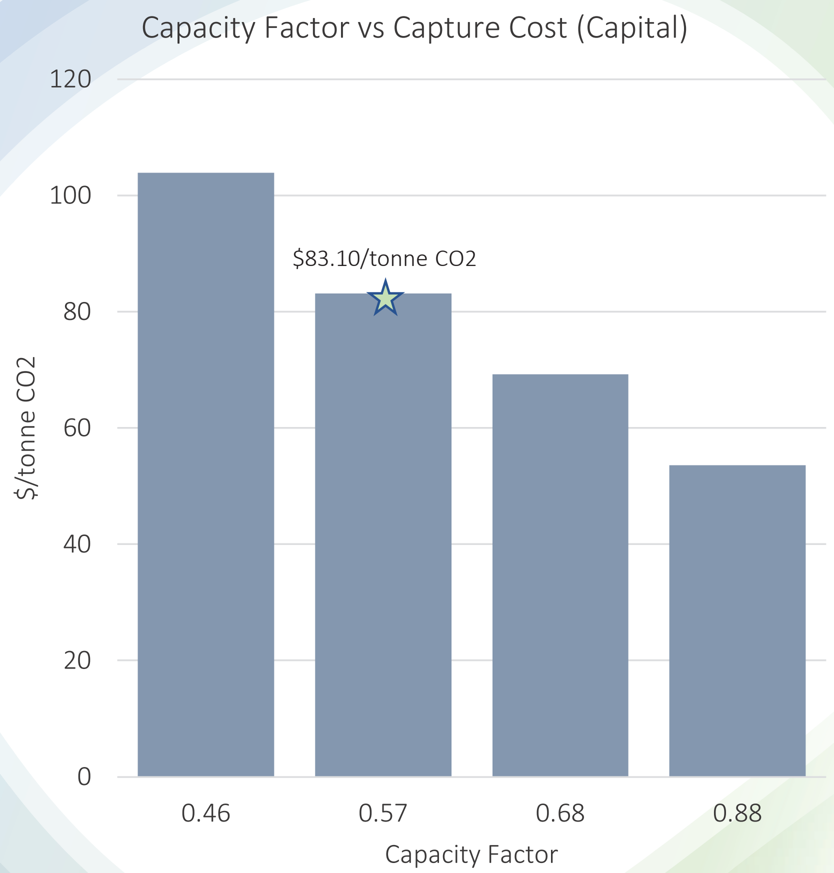
- Based on 5,000 hrs of Operation per year (420MW NGCC Power Plant)
- Interest rate = 6%
- Return on Equity = 12%
- Capacity Factor = 0.57 (645,000 per year CO2 captured)



Data: The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com

Effect of Capacity Factor on Capture Cost

- Based on 5,000 hrs of Operation per year (420MW NGCC Power Plant)
- Annualized Capital Cost 53.6M
- Loan Life = 15 years
- Interest rate = 6%
- Return on Equity = 12%



Data: The Chemical Engineering Plant Cost Index. Chemical Engineering, http://www.chemengonline.com

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Joe Lloyd and Darryl Nitschke (Panda Power)
Bechtel National Inc. Team

Panda Energy Sherman Power Plant

Access to Full Report:

2.2. Lessons learned: Mustang FEED and comparison to Panda FEED

Jorge Martorell (Univ. of Texas at Austin)

Lessons Learned: Mustang FEED and comparison to Panda FEED

Jorge L. Martorell, Gary T. Rochelle, Michael Baldea

McKetta Department of Chemical Engineering

The University of Texas at Austin

7th IEAGHG CCS Cost Network Workshop

April 12-13, 2023

Part 1:

- Summary of Mustang FEED and lessons learned

  G T Rochelle et al. “Front-End Engineering Design for Piperazine with the Advanced Stripper”. US Dept. of Energy Tech. Rep. DE-FE0031844. (2022) (in process) DOI: (TBD)

  URL: https://netl.doe.gov/project-information?p=FE0031844

- Mustang rating model optimization

  A Suresh Babu et al. “Maximum Operating Profit of PZAS at Off-Design Conditions by a Rigorous Rating Model for a 460 MW NGCC”. *Proceedings of GHGT-16.* (2022) DOI: https://dx.doi.org/10.2139/ssrn.4283094

Part 2:

- FEED comparison: Mustang and Panda

  Bechtel National, Inc. “Front-End Engineering Design (FEED) Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant”. US Dept. of Energy Tech. Rep. DE-FE0031848. (2021) DOI: https://doi.org/10.2172/1836563

  J L Martorell et al. “Lessons Learned: Comparing Two Detailed Capital Cost Estimates for Carbon Capture by Amine Scrubbing”. *Ind. & Eng. Chem. Res.* (2023) DOI: https://doi.org/10.1021/acs.iecr.2c04311

Part 1:
Cost Details from Mustang FEED

Mustang FEED Outline

- Project structure and objectives
- PZAS: a superior 2nd generation process
- Mustang Station: low energy cost, abundant space, EOR pipeline
- Design decisions and opportunities for improvement
- Project costs: capital, annual, business case
- Profit optimization rating model

The objective: Accurate installed cost of Piperazine with the Advanced Stripper (PZAS™) on NGCC at GSEC Mustang Station

Complementary benefits:

- Develop commercial project at Mustang Station
- Qualify PZAS for use on NGCC and cogeneration (CHP)
- Provide commercial cost detail
    - Optimize PZAS & other 2nd generation processes
    - Guide R&D of capture technology

Funding: $5.6MM

- $4.2MM US Department of Energy
- $1.4MM ExxonMobil, Total, Chevron, Honeywell UOP

Performance Period: October 2019 – June 2022

Participants:

- Golden Spread Electric Cooperative (GSEC) – Host
- University of Texas at Austin (UT) – Modeling/Technology
- Trimeric – Process Engineering
- AECOM – EPC (Engineering, Procurement, Construction)

Comprehensive public report submitted July 2022 (to be released shortly)

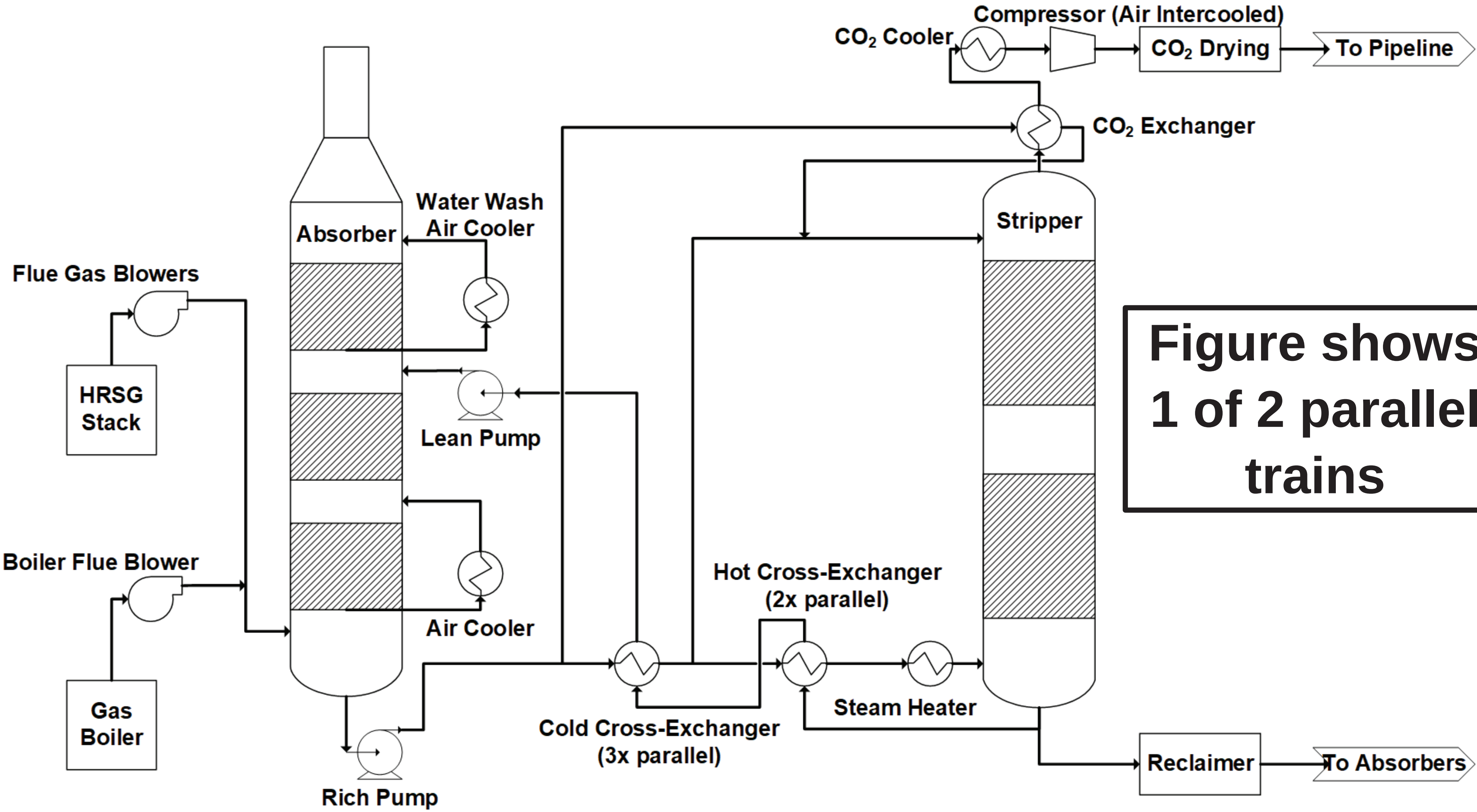
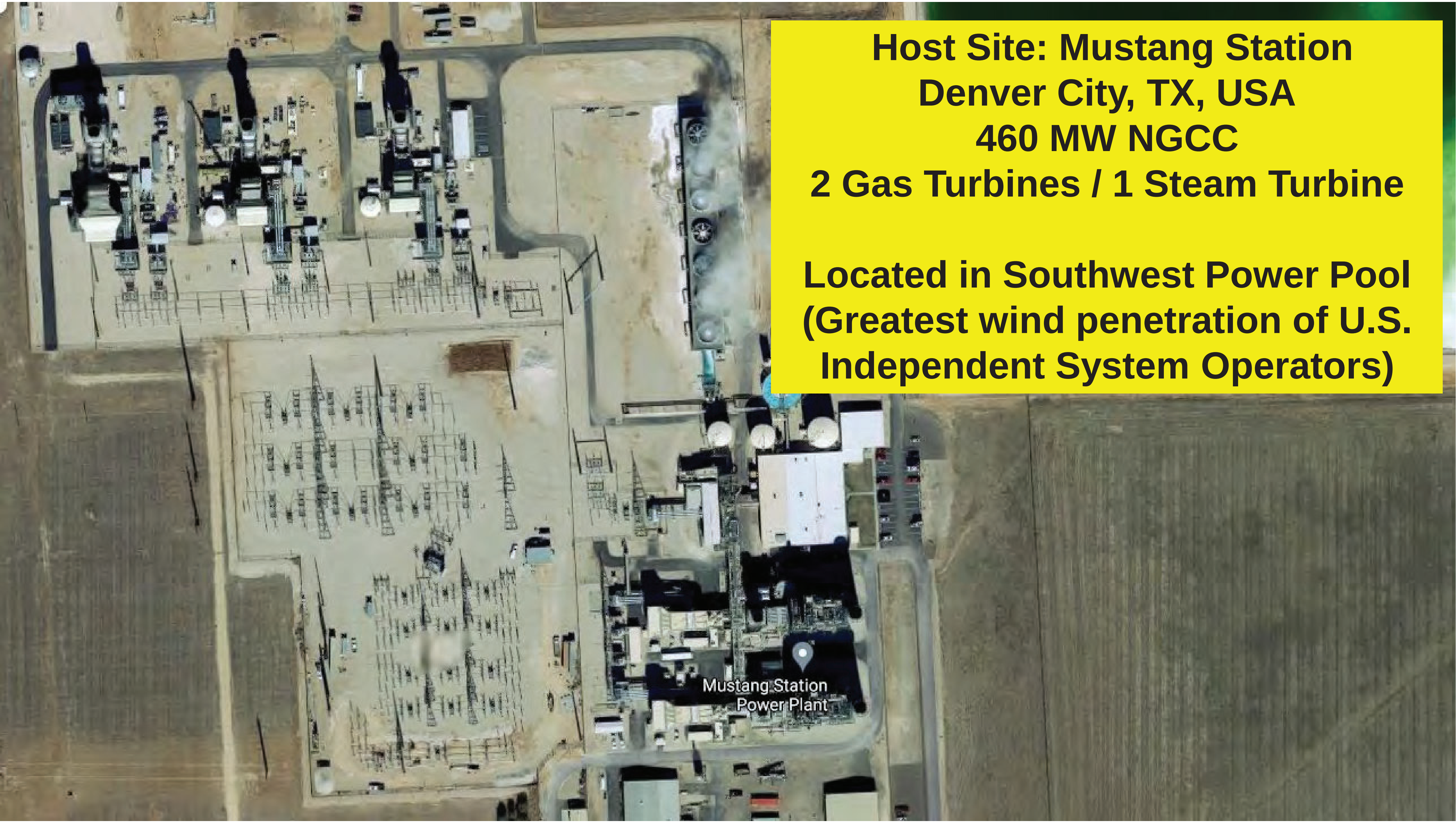


Figure shows 1 of 2 parallel trains

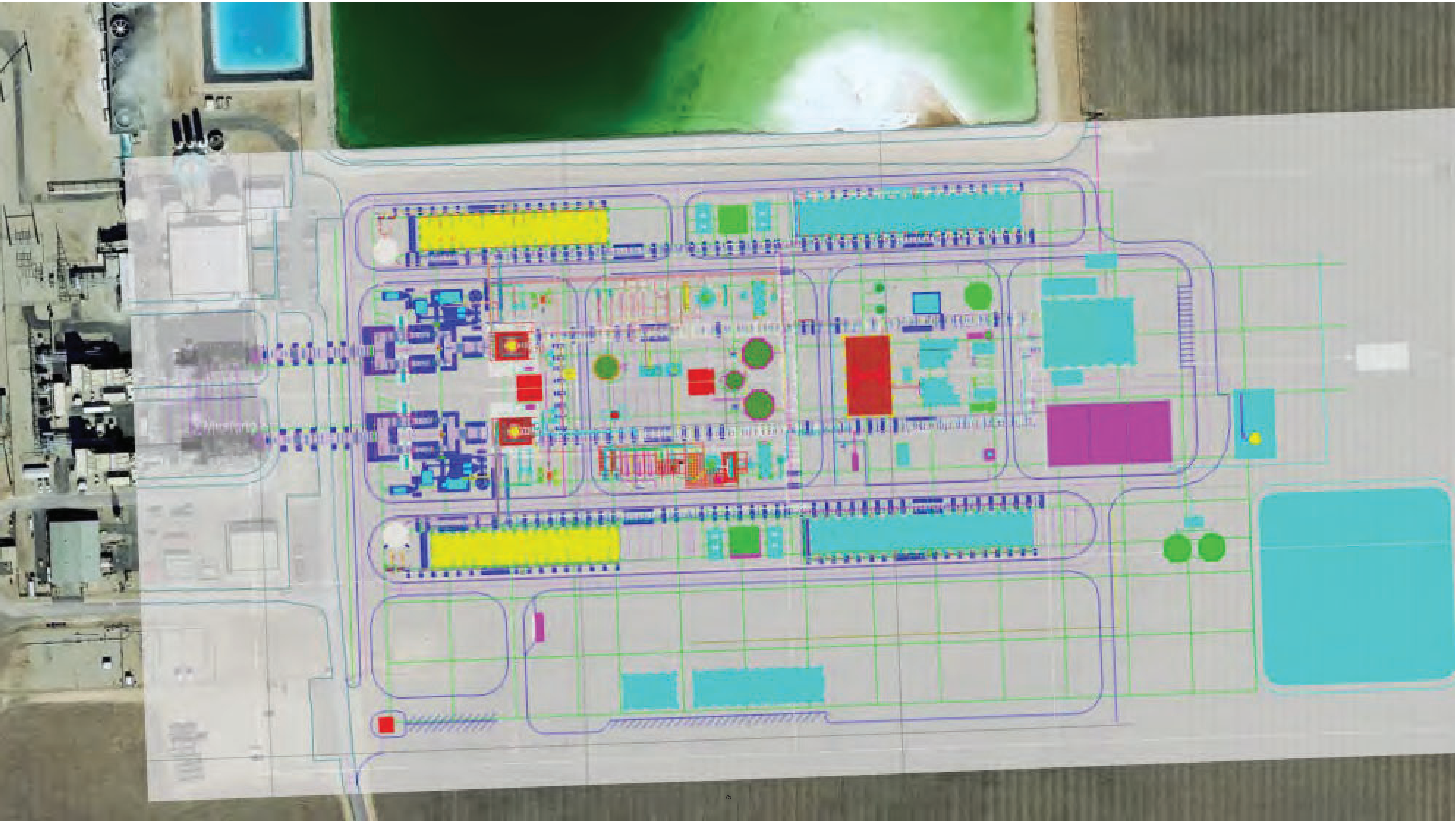


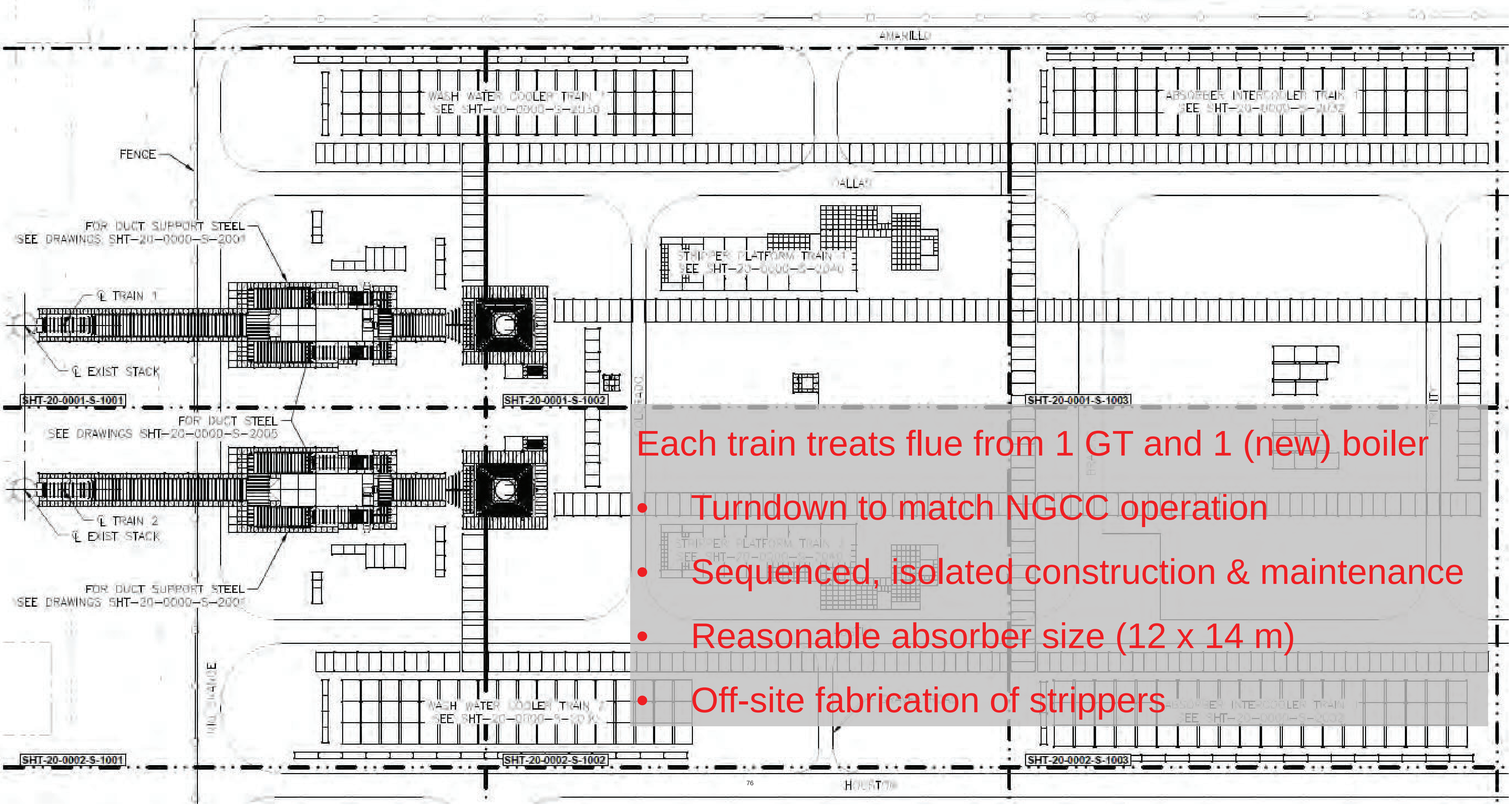
Host Site: Mustang Station
Denver City, TX, USA
460 MW NGCC
2 Gas Turbines / 1 Steam Turbine

Located in Southwest Power Pool
(Greatest wind penetration of U.S. Independent System Operators)

Changing perspective on the Mustang site

	Proposal, May 2019	FEED report, July 2022
Space	Excellent	Spread out, still good
CO_2 disposal	Existing pipeline to EOR	Existing pipeline to storage
Cooling	Available cooling tower	No water, air cooling required
Steam supply	Extraction from turbine	Gas-fired boiler
Fuel cost	$2/MMBTU (~6 €/MWh)	$8/MMBTU (~25 €/MWh)
CO_2 rate	126 tonne/hr	190 tonne/hr
Electricity	Wholesale LMP = $20/MWh	Retail? = $100/MWh
Load factor	>52%, higher with good CO_2 value and low fuel cost	<52%, lower with high fuel cost & more renewables
Financing	<4% with non-profit	10% IRR with private capital
Capital cost	$270MM	$725MM





Each train treats flue from 1 GT and 1 (new) boiler

- Turndown to match NGCC operation
- Sequenced, isolated construction & maintenance
- Reasonable absorber size (12 x 14 m)
- Off-site fabrication of strippers

CO_2 removal: 90% at median ambient temperature

Air cooling: absorber intercooling, water wash, compressor

- Water wash has 24-hour water balance in summer

Steam: one package boiler for each train (flue gas treated)

Designed for moderate energy requirement:

- 3.0 GJ/t_{CO_2} with 5 plate-and-frame exchangers per train
- 2.5 GJ/t_{CO_2} achievable with 10 exchangers per train

Compression: one 3-stage reciprocating compressor per train

Project costs and business case

	$ Millions
Total direct cost	384
Total indirect cost	93
Engineering	37
Insurance, taxes, bonds, and permits	19
Contingency	105
Contractor overhead and profit	60
Project total cost	**698**
Owner’s cost	27
Total overnight cost	**725**

Direct Cost	$ Millions	%	Potential savings
Total	**384**	**100.0**	
Air cooling	90.0	23.0	**Water cooling**
Absorber	37.0	10.0	**Carbon steel**
CO_2 compression	24.2	6.0	
Ductwork, dampers, fans	21.6	5.6	**Shorten ductwork**
Solvent reclaiming	19.6	5.1	**Revisit**
Stripper, CO_2 conditioning	17.4	4.5	
Steam generation	14.1	3.7	**Steam extraction**
Solvent heat exchangers	9.5	2.5	**More exchangers**

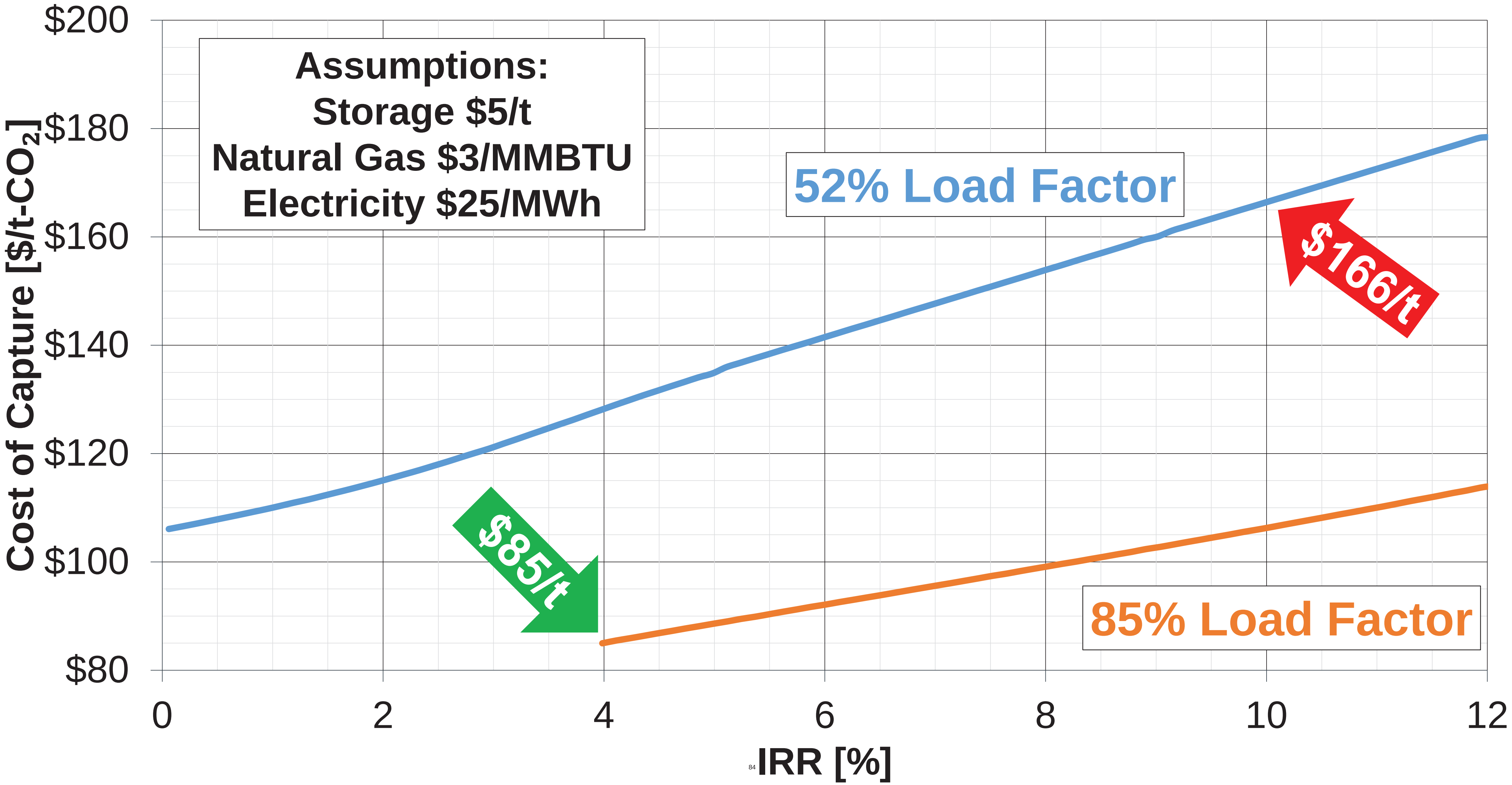
Annual Variable Operating Cost	Assumptions	$MM
Total	**52% load factor**	**21.5**
Natural gas –15% increase in total fuel rate +[more exchangers to reduce heat duty] +[steam extraction]	354 MMBTU/hr (annual avg) at $3/MMBTU	9.5
CO_2 tariff for transport & storage	$5/tonne	4.3
Electricity –7% decrease in NGCC net output +[replace air cooling with water cooling]	33 MW @ $25/MWh	3.8
Piperazine solvent		2.0
Other (caustic, water, TEG, N_2, waste)		1.9

Annual Fixed Operating Cost	$MM
Total annual fixed operating costs	**32.6**
Property tax & insurance (year 1 @ 2.5%) +[negotiate for local tax break]	18.2
Maintenance labor & materials	9.9
Operating labor	3.3
Administrative & support labor	1.2

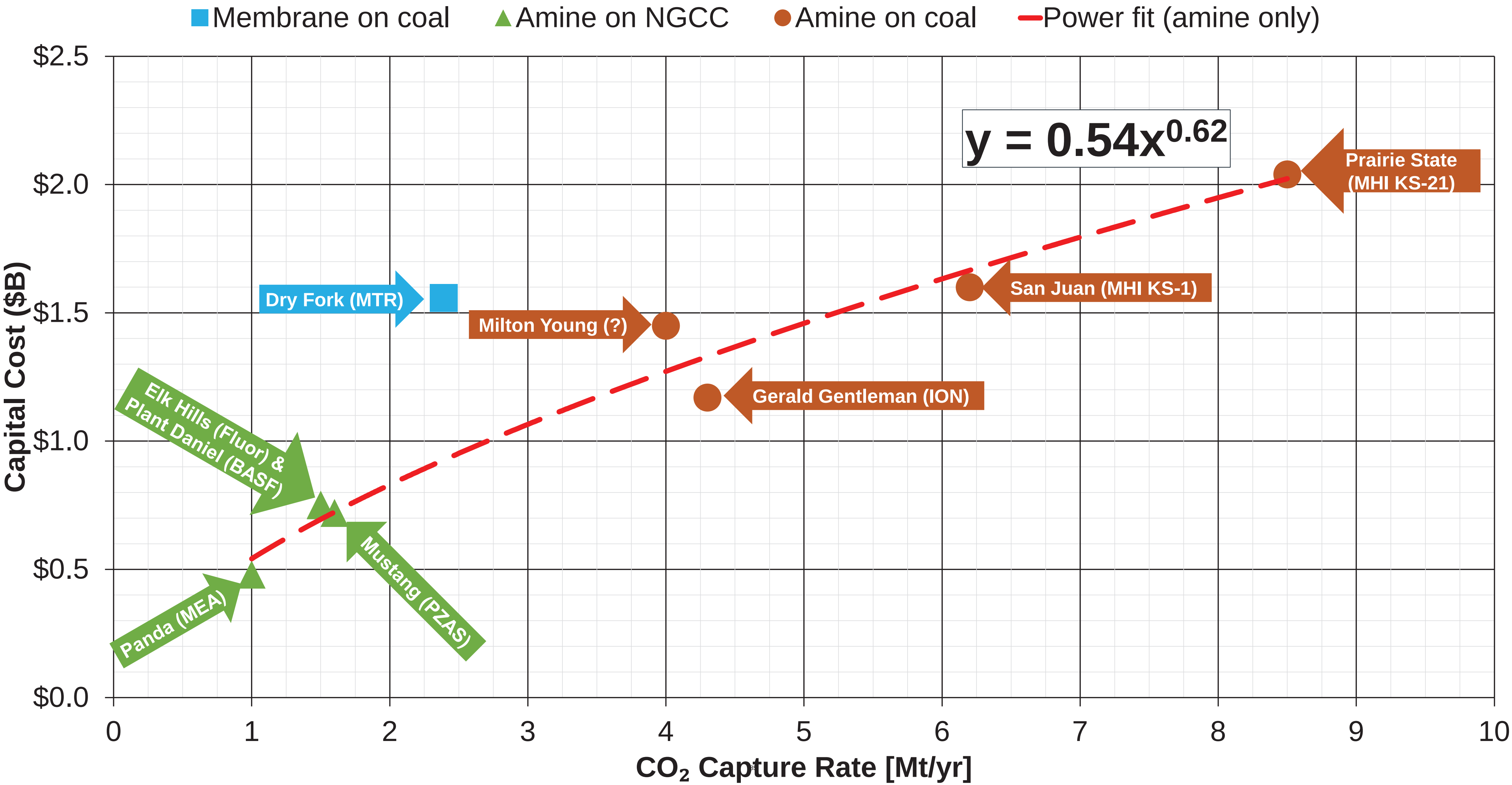
Net cash flow at base case conditions

Load factor: 52%, Fuel: $3/MMBTU ($10/MWh), Electricity: $25/MWh

	$ Millions
Income from 45Q @ $85/tonne	+64.0
Fixed annual costs	-32.6
Variable annual costs	-21.5
Net cash flow	+9.9


Assumptions:
Storage $5/t
Natural Gas $3/MMBTU
Electricity $25/MWh
52% Load Factor
85% Load Factor
$166/t
$85/t
$200
$180
$160
$140
$120
$100
$80
Cost of Capture [$/t-CO2]
0
2
4
6
8
10
12
IRR [%]

Cost vs capacity of DOE FEED studies



FEED defines technically feasible design for Mustang Station

- Capital cost: $725MM
- $/tonne at $3/MMBTU ($10/MWh) depends on load & financing:
  - $85/t$_{CO_2}$ at 4% IRR, 85% LF
  - $166/t$_{CO_2}$ at 10% IRR, 52% LF

Major opportunities for enhanced performance and reduced cost

- Steam extraction from existing turbine
- More absorber packing to get >97% removal, near C-neutral
- Additional exchanger area to reduce natural gas consumption

Detailed public FEED provides basis for NGCC or CHP demo

Ideal site: cooling water, steam extraction, low renewables, high LF

Optimization of Mustang FEED rating model

FEED **design model** was used to create a **rating model**[1]:

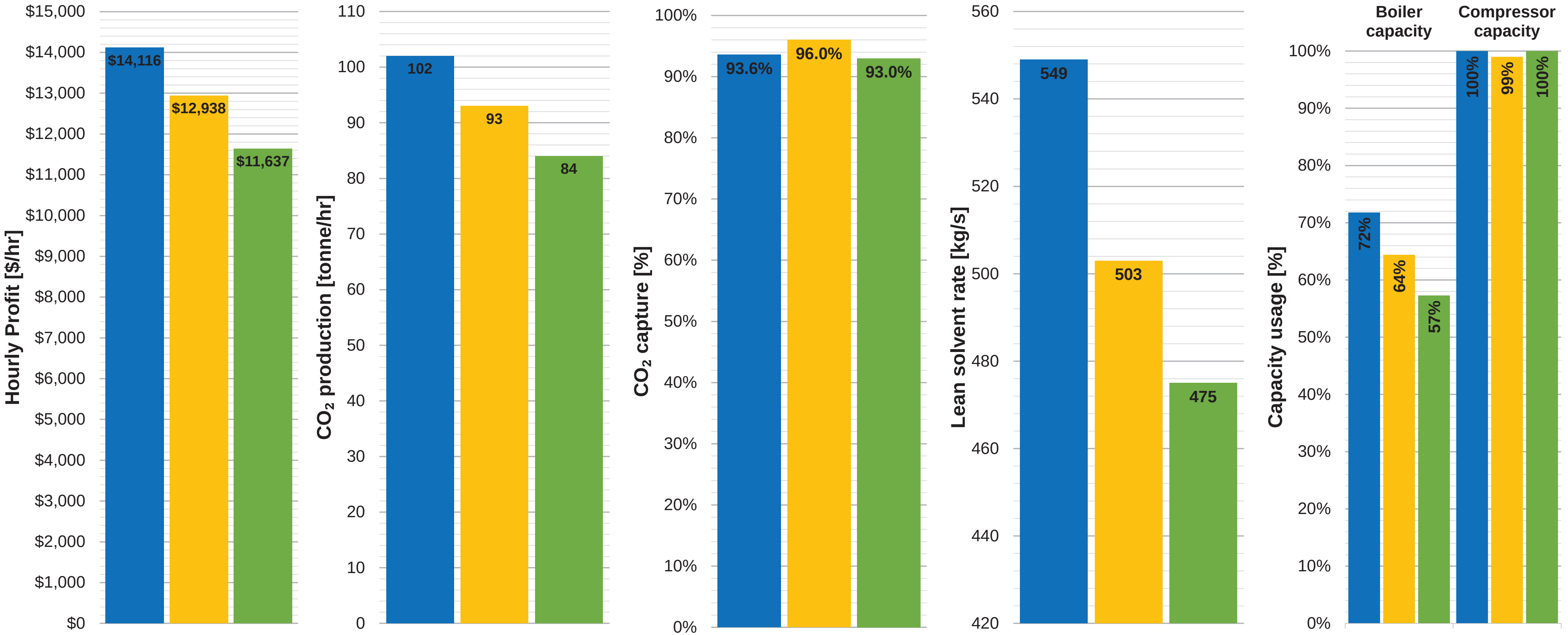
- Fix equipment, vary operating conditions *s.t.* equipment constraints
- Maximize hourly operating profit:

$$Profit = \frac{\$}{t_{CO_2}} \times rate_{CO_2} - \frac{\$}{MWh} \times power - \frac{\$}{MMBTU} \times duty_{boiler}$$

Design & Rating + Surrogates → Process surrogate and optimization

Rating model gives optimum operating conditions for given load and ambient conditions

[1] A Suresh Babu, et al. *Proceedings of GHGT-16* (2022) https://dx.doi.org/10.2139/ssrn.4283094



Case A: 4°C ambient

Case C: 18 °C ambient

Case E: 41 °C ambient

Key assumptions: 95% Load, NG at $3/MMBTU, Electricity at 7000 BTU/MWh, CO_2 value $80/tonne

Conclusions

- **Maximum profit at 93% – 96% removal**
- Capture plant more profitable in winter
- Low lean loading results in low reboiler duty (2.2 – 2.4 GJ/t_{CO_2}) and improved profit
- Solvent precipitation avoided even at low loading and ambient T
- **At low gas price, value of carbon credit exceeds cost of gas. Therefore, burning gas in boilers drives profitability at high lean loading (low CO2 flow)!**

Part 2:

Comparing Mustang FEED and Panda FEED

"Mustang FEED"[1]

Cost estimate for PZAS, second-generation amine scrubbing process

"Panda FEED"[2]

Cost estimate for a generic design using low-cost solvent (MEA)

Objective of this comparison[3]

Both use amine scrubbing CO_2 capture at NGCCs in Texas

Results and cost estimates were published in extensive detail

Validate cost estimates, draw insights to reduce capital cost

[1] G T Rochelle, et al. "Front-End Engineering Design for Piperazine with the Advanced Stripper Final Report" (2022) https://netl.doe.gov/project-information?p=FE0031844

[2] W Elliott, et al. "Front-End Engineering Design Study for a Carbon Capture Plant Retrofit to a Natural Gas-Fired Gas Turbine Combined Cycle Power Plant" (2021) https://doi.org/10.2172/1836563

[3] J L Martorell, et al. *Ind. & Eng. Chem. Res.* (2023) 62,110:4433-4443 https://doi.org/10.1021/acs.iecr.2c04311

Panda handles 19% less flue gas, captures 31% less CO_2

	Mustang	Panda
NGCC flue gas flow [t/hr]	2880	3700
Flue gas feed to capture unit [t/hr]	3160 (NGCC + boiler)	2530
Captured CO_2 stream [t/hr]	200	130
Design Capture [%]	90	85

	Mustang	Panda
Solvent	5 m PZ (~30 wt%)	35 wt% MEA
Steam	Package boilers	Steam extraction
Cooling	Air cooling	Cooling water from existing site capacity
Cost Estimate	Bottom-up cost estimate: • Vendor quotes for major equipment • Piping, ductwork, I&E, civil, etc. estimated from detailed site layouts	
	-20% to +30%	+/- 20%

Cost ($ Millions)	Mustang	Panda
Total cost	**$724**	**$477**
Direct cost, as reported	$385 ($A$)	$450 ($A$)
Detailed eng. & commissioning	$37 ($B_1$)	$59
Indirect field costs	$93 ($B_2$)	
Contingency	$104 (Excluded)	$34 ($C$)
Owner's cost	$27 (Excluded)	$5 ($D$)
Contractor's ovhd & profit	$60 ($E$)	(Included)
Adjusted direct field cost	**$574** $A + B_1 + B_2 + E$	**$411** $A - C - D$

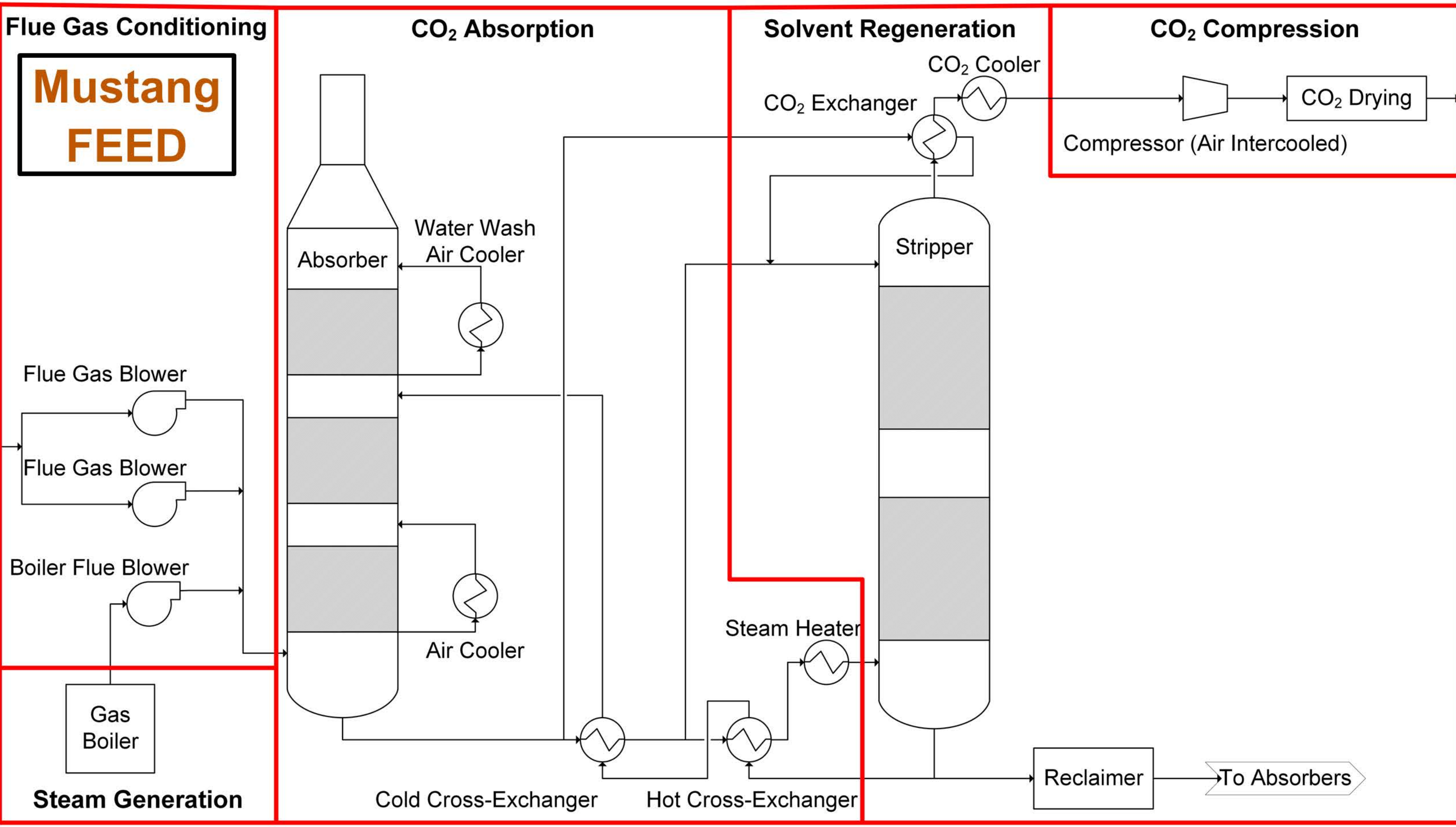
1. Reported costs **adjusted** to same set of inclusions
2. Cost of each process sub-area **scaled** with flue gas or CO_2 flow:

$$Cost_{Scaled} = Cost_{Mustang} \times \left(\frac{Flow_{Panda}}{Flow_{Mustang}}\right)^{(0.6)}$$

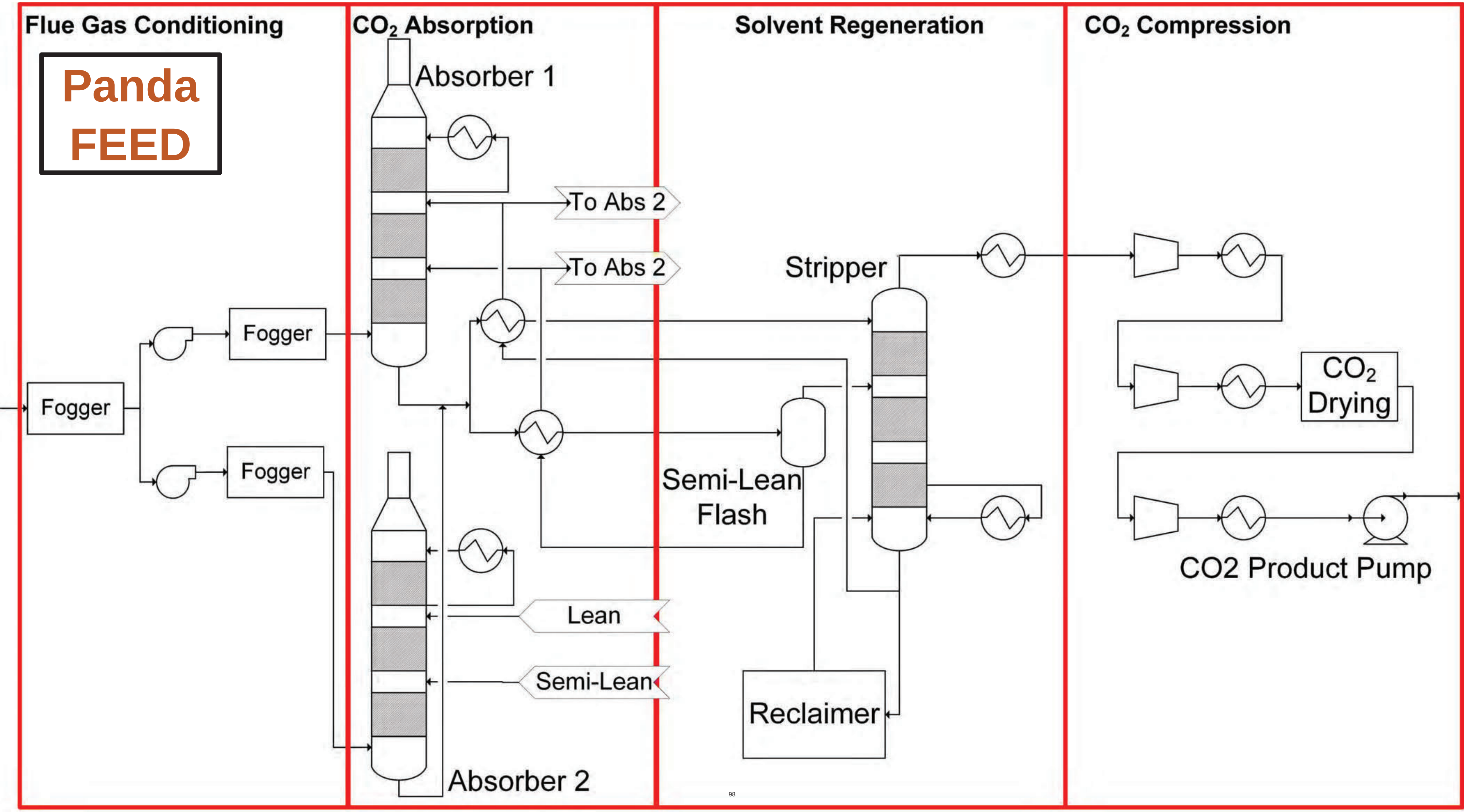
Scaling intended to represent estimated cost for:

- Same PZAS process configuration
- Same Mustang site constraints (ductwork, boilers, air cooling, etc.)
- Capacity of the Panda FEED

Cost ($ Millions)	Mustang Adjusted	Panda Adjusted	Mustang Scaled
TOTAL	**$574**	**$411**	**$489**

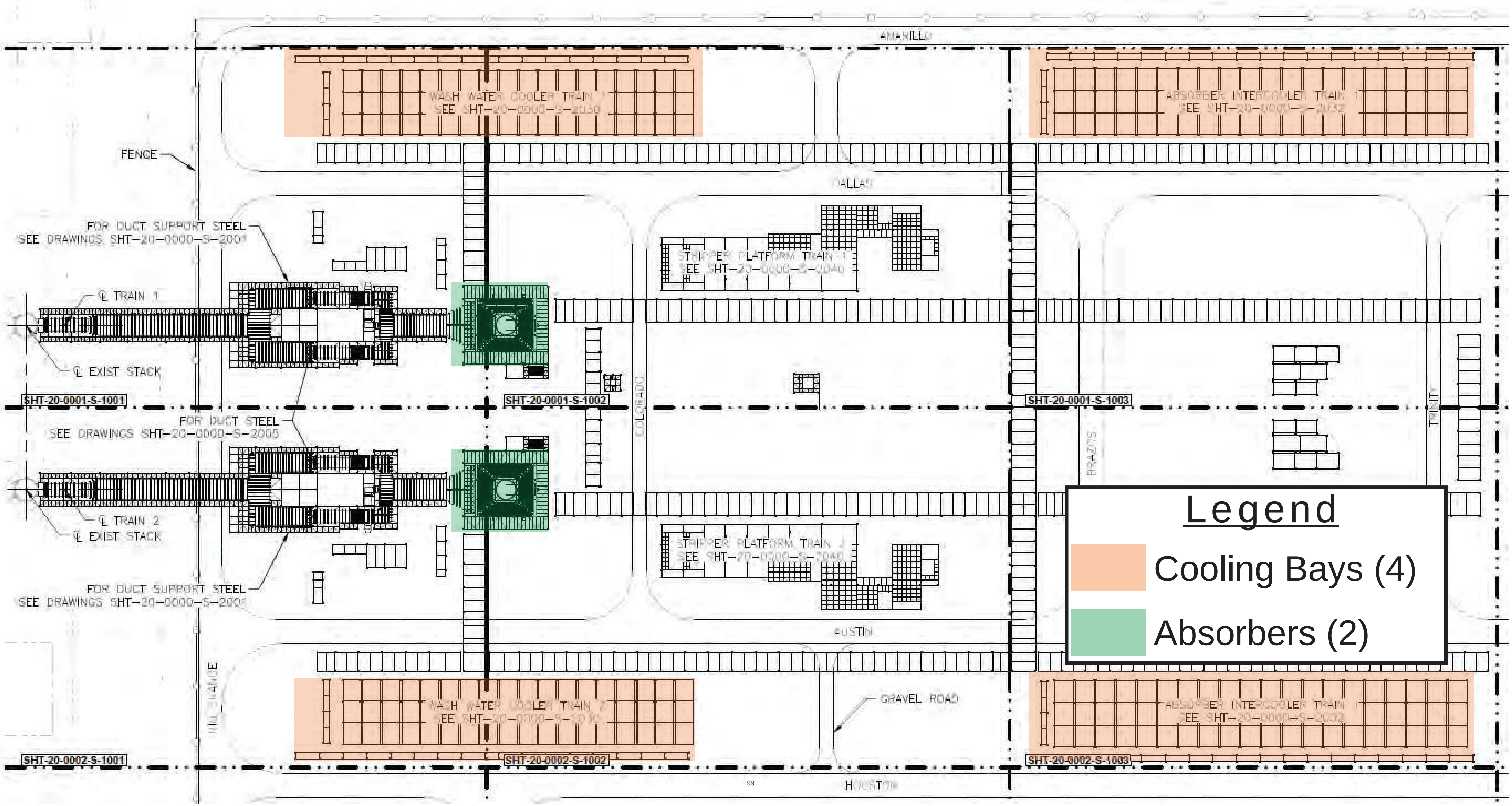


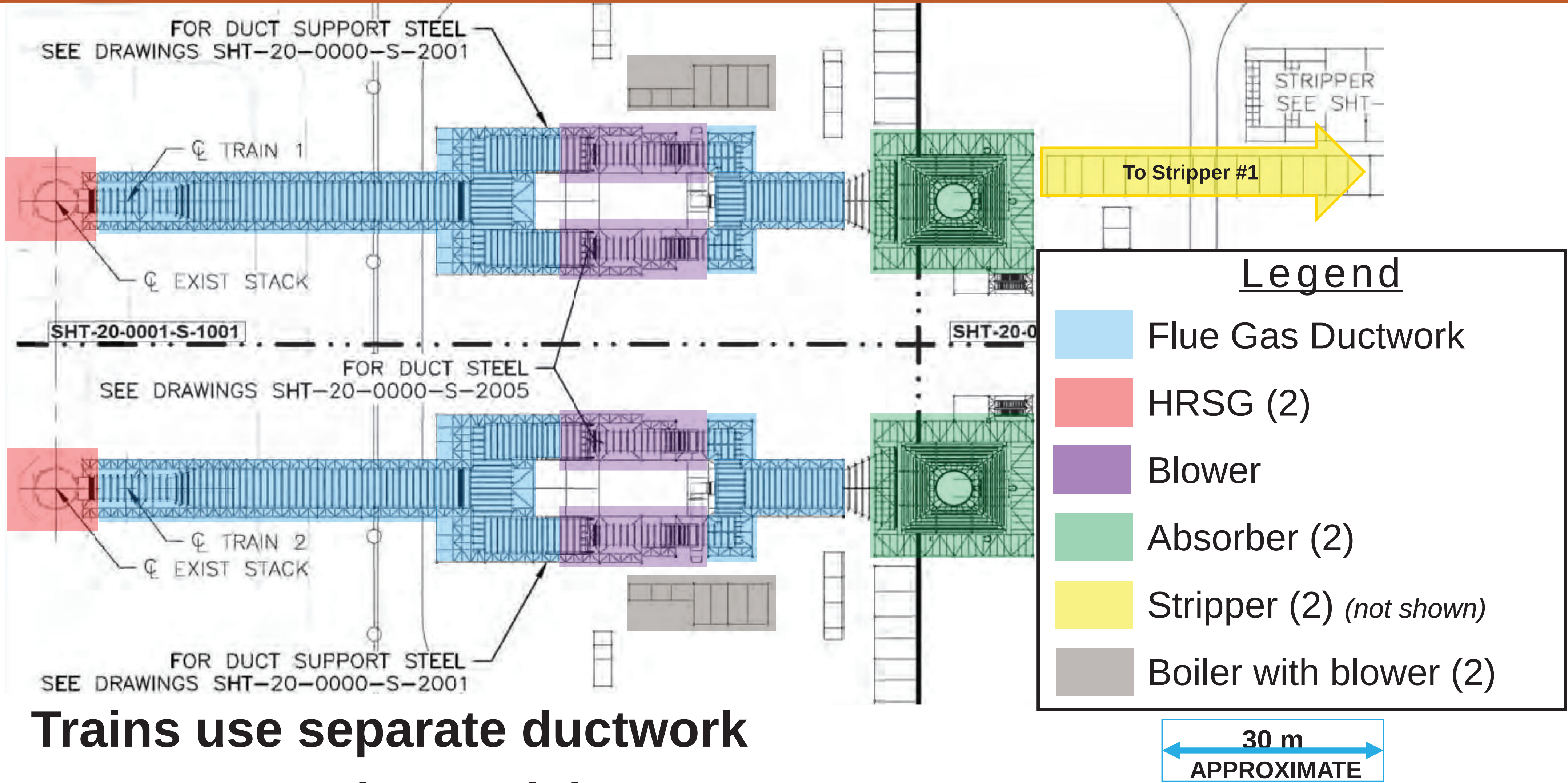
Flue Gas Conditioning
Mustang FEED
CO2 Absorption
Solvent Regeneration
CO2 Compression
CO2 Cooler
CO2 Exchanger
CO2 Drying
Compressor (Air Intercooled)
Water Wash Air Cooler
Absorber
Stripper
Flue Gas Blower
Flue Gas Blower
Boiler Flue Blower
Air Cooler
Steam Heater
Gas Boiler
Steam Generation
Cold Cross-Exchanger
Hot Cross-Exchanger
Reclaimer
To Absorbers



Flue Gas Conditioning
Panda FEED
Fogger
Fogger
Fogger
CO2 Absorption
Absorber 1
To Abs 2
To Abs 2
Lean
Semi-Lean
Absorber 2
Solvent Regeneration
Stripper
Semi-Lean Flash
Reclaimer
98
CO2 Compression
CO2 Drying
CO2 Product Pump

Air Cooling – Mustang





Trains use separate ductwork

180 m (per train)

100

Site Arrangement – Panda

Legend

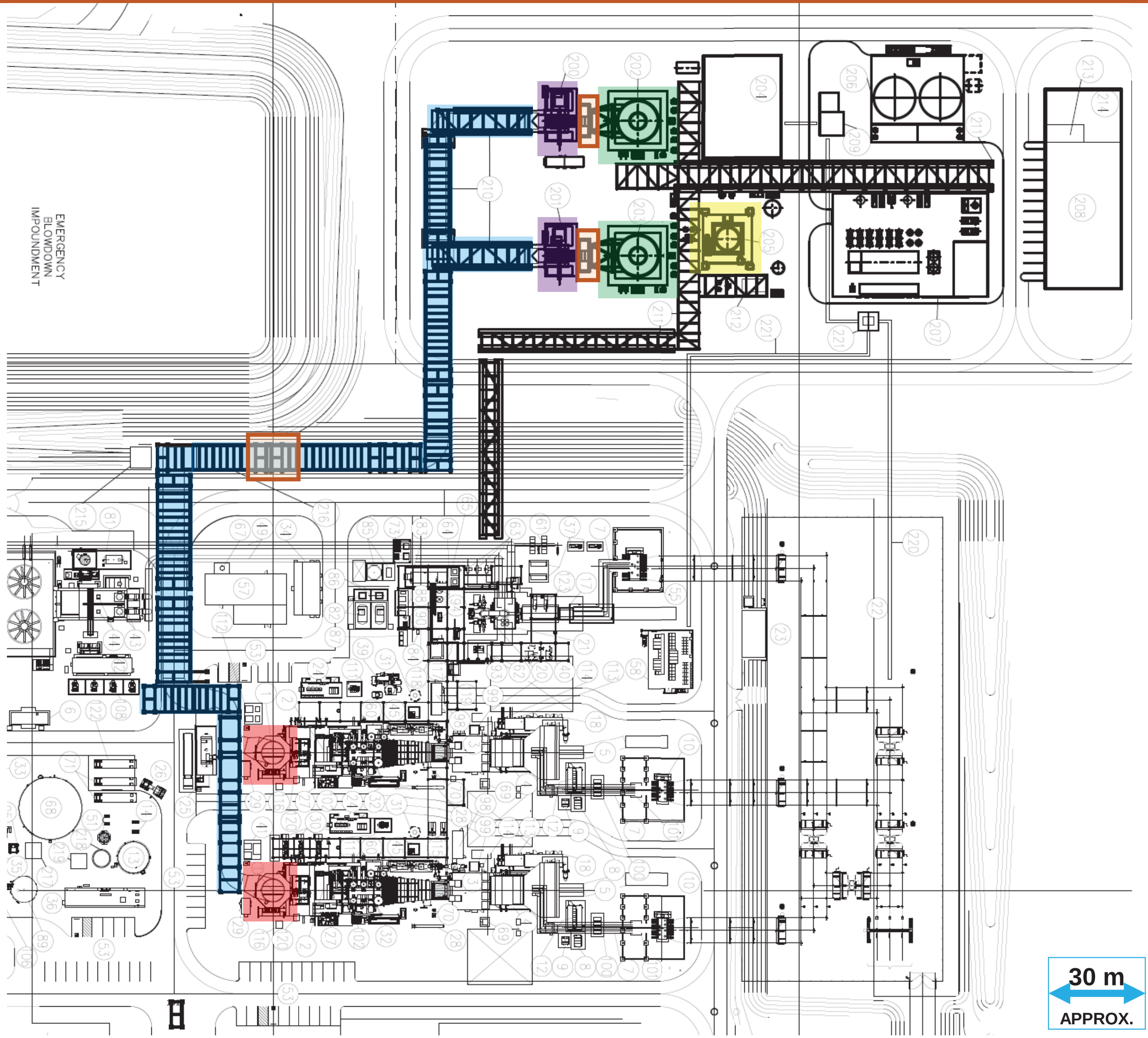
- Flue Gas Steel Rack
- HRSGs (2)
- Blower
- Absorbers (2)
- Stripper (1)
- Foggers (3)

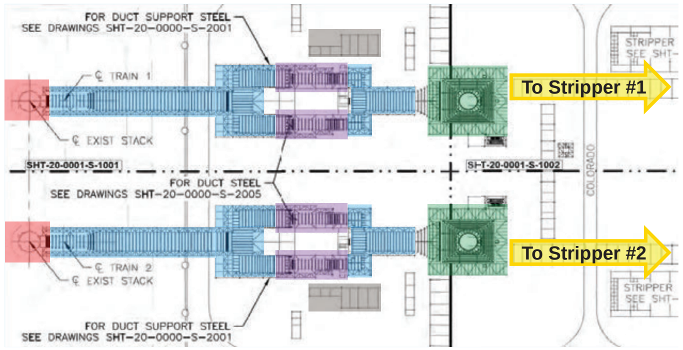
Common duct to absorbers

Carbon steel: 170 m

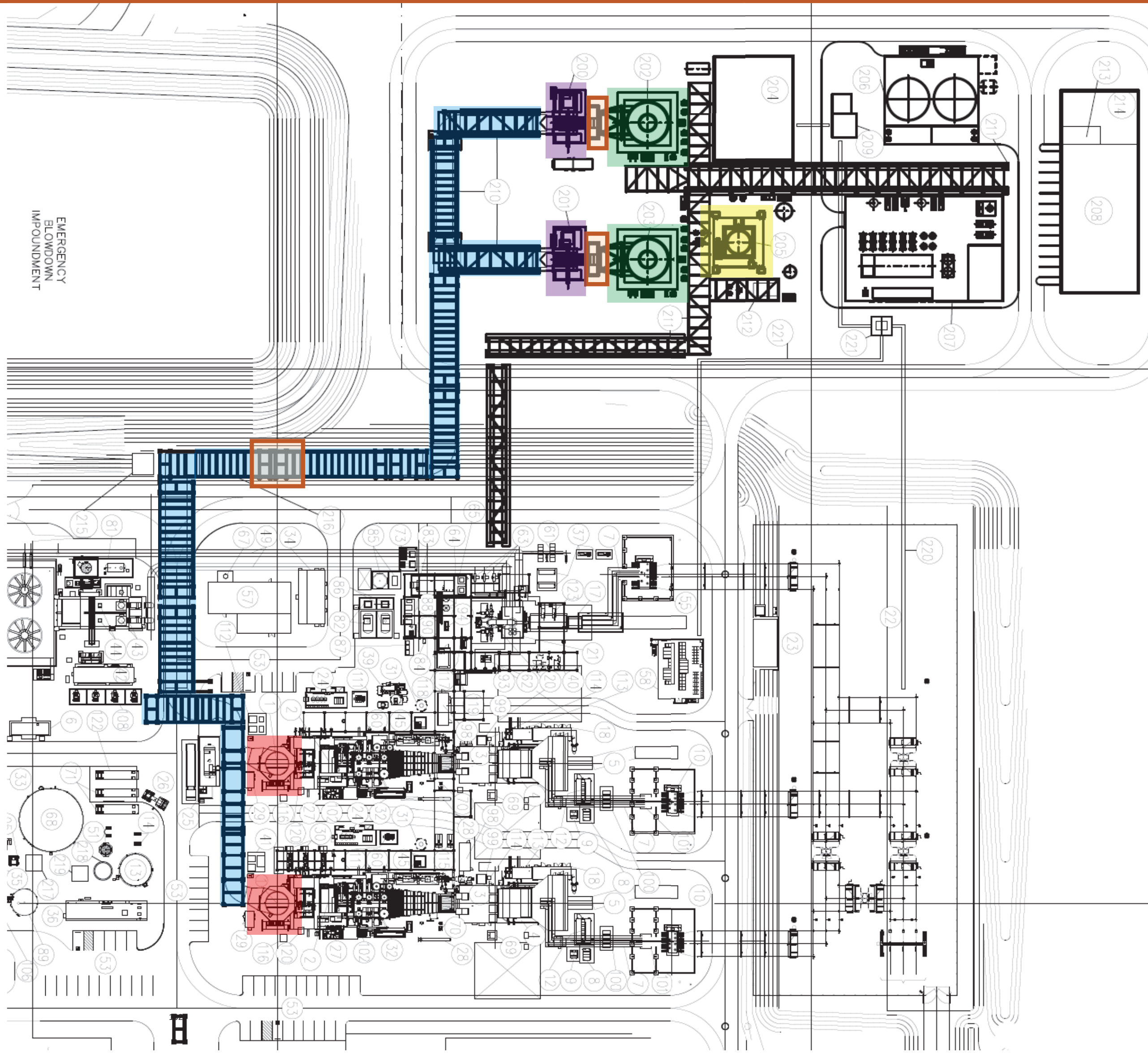
Stainless steel: 220 m

Total: 395 m




FOR DUCT SUPPORT STEEL
SEE DRAWINGS SHT-20-0000-S-2001
℄ TRAIN 1
℄ EXIST STACK
To Stripper #1
STRIPPER
SHT-20-0001-S-1001
SHT-20-0001-S-1002
FOR DUCT STEEL
SEE DRAWINGS SHT-20-0000-S-2005
℄ TRAIN 2
℄ EXIST STACK
To Stripper #2
STRIPPER
FOR DUCT SUPPORT STEEL
SEE DRAWINGS SHT-20-0000-S-2001


30 m
APPROX.


EMERGENCY
BLOWDOWN
IMPOUNDMENT

		1: Mustang FEED	2B: Mustang Alternate	3S: Panda Scaled
Cross-section		Rectangular	Round	Round
Cross-section area	m^2	175	175	175
Packed height	*m*	10.6	10.6	10.6
Total cost (reported)	***$MM***	**18.5**	**20.9**	**16.2**
Cost of scope	***$MM***	**19.7**	**18.2**	**14.9**

Scope includes single absorber with engineered procurements and steel. Excludes foundation, instrumentation, piping, pumps.

Key factors in capture plant cost 39

- Estimates for both FEEDs were similar, adjusting for capacity
  - Ancillary equipment costs had higher impact than expected
  - Ancillaries at Mustang offset cost advantage of 2nd gen process

- Site-specific factors such as availability of cooling water or extracted steam have significant impact on cost

- Simple models excluding costs like ductwork, utilities leave out significant costs which can change the optimal design

Mustang FEED:

- FEED is technically feasible, CAPEX=$725MM, $/t_{CO_2}$= $85 to $166 depending on IRR and LF
- Major opportunities for enhanced performance and reduced cost

FEED Rating Model:

- >90% capture feasible and maximizes profit in all cases considered
- Reboiler duty lower than design (2.2 – 2.4 GJ/t_{CO_2})
- C credit leads to perverse incentive for boilers if gas price is low

FEEDs Cost Comparison:

- Estimates for both FEEDs were similar, adjusting for capacity
- Site-specific factors have significant impact on cost, possibly more than choice of technology

Thank you to our collaborators:

Mustang FEED

Golden Spread Electric Cooperative (Mustang Station host site)

US Dept. of Energy National Energy Technology Laboratory: Krista Hill (project manager)

UT Austin (Texas Carbon Management Program): Gary Rochelle, Fred Closmann, Miguel Abreu, Benjamin Drewry, Tianyu Gao, Jorge Martorell, Athreya Suresh Babu

AECOM: William A. Steen, Karen Farmer, Scott Bryan, Max Bernau

Trimeric Corporation: Andrew Sexton, Katherine Dombrowski, Duane Myers, Michael Marsh, Brad Piggott, Rosalind Jones

Kronos Management: Jeff Lee

Mustang rating model

UT Austin: Athreya Suresh Babu, Miguel Abreu, Benjamin Drewry, Yee Lee Chen, Gary Rochelle

Mustang/Panda comparison

UT Austin: Jorge Martorell, Gary Rochelle, Michael Baldea

Bechtel: William Elliott, Camila Bauer

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This paper was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

One contributor to this work (Gary Rochelle) consults for a process supplier on the development of amine scrubbing technology. The terms of this arrangement have been reviewed and approved by the University of Texas at Austin in accordance with its policy on objectivity in research. This author also has financial interests in intellectual property owned by the University of Texas that includes ideas reported in this work.

Thank you!

jorge.martorell@utexas.edu

Session 3: Direct Air Capture

3.1. Scaling and cost projections of carbon dioxide removal (CDR) via direct air capture (DAC).

Jan Wurzbacher (Climeworks)

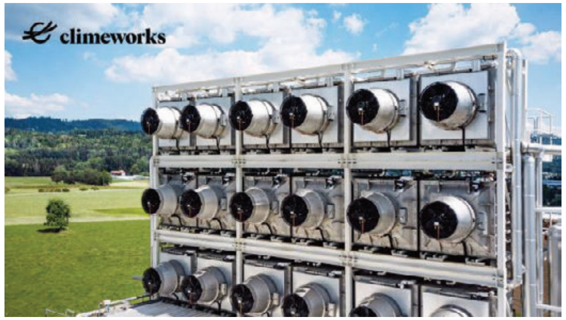
Scaling and Cost Projections of Carbon Dioxide Removal (CDR) via Direct Air Capture (DAC)

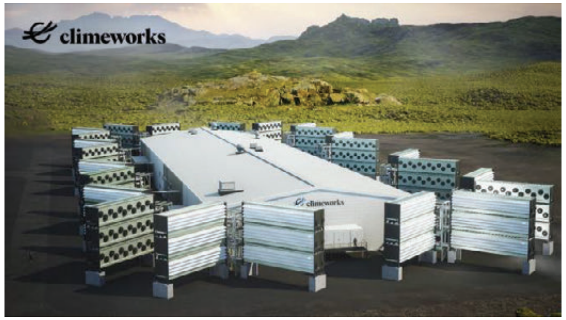
Dr. Jan Wurzbacher, Founder & Co-CEO

7th IEAGHG CCS Cost Network Workshop

12 April 2023

Climeworks' journey to impact at scale





2009

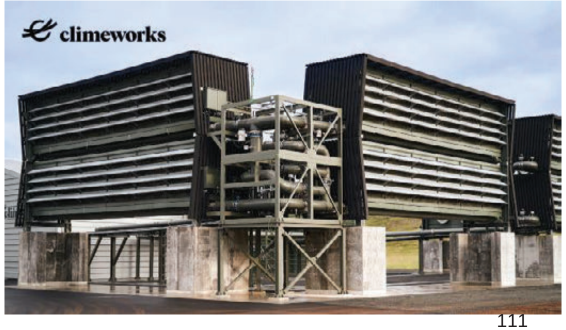
2017
World's first commercial DAC plant
Switzerland
Hinwil

2021
First large-scale DAC+S[1] plant "Orca" (~3 kt CDR/year)
Iceland
Hellisheiði

2024
Launch of "Mammoth" plant (~28 kt CDR/year)
Iceland
Hellisheiði

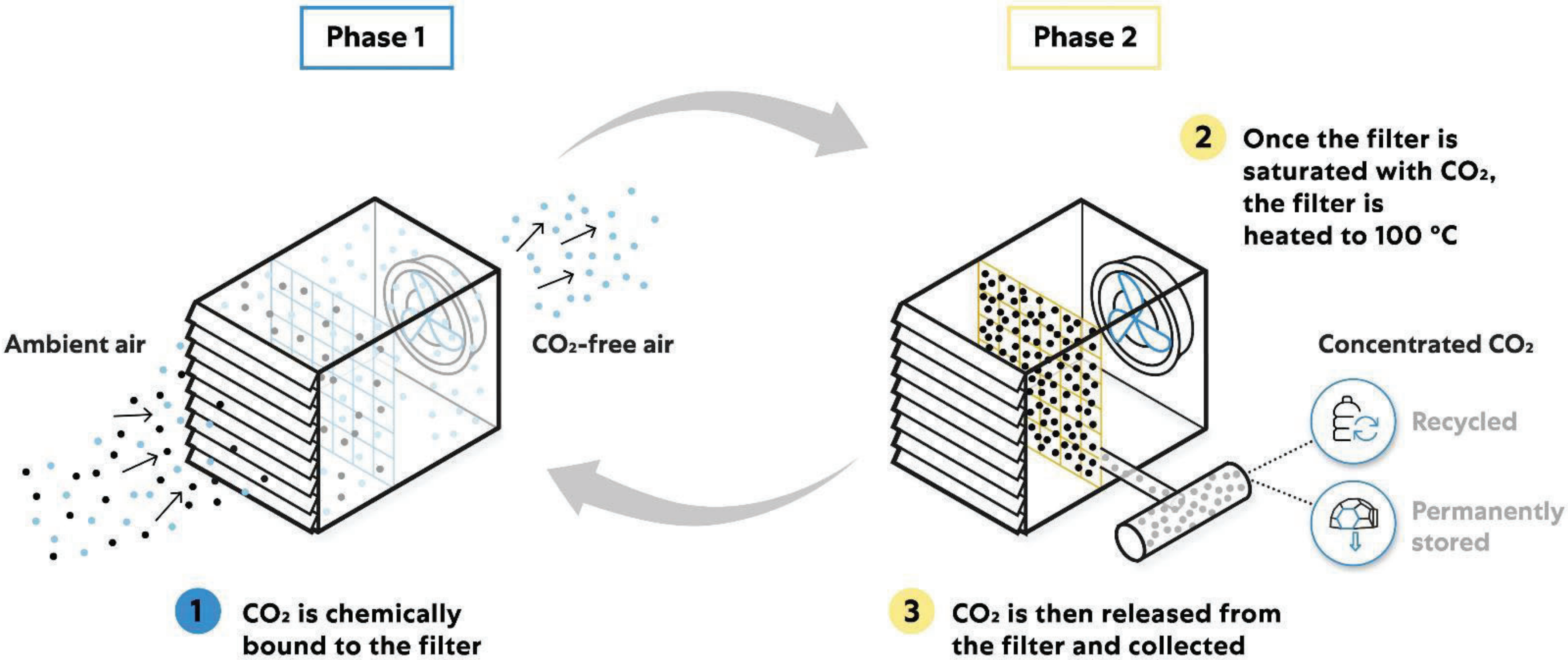
2030
Total CDR capacity: Megaton+
Global

2050
Total CDR capacity: Gigaton+
Global



1. DAC+S: Direct Air Capture + Storage

Climeworks solid sorbent-based adsorption process



We’ve operated the world’s largest DAC plant for 1.5 years

The world’s **only** commercial direct air capture & storage facility

Started operation in September **2021**

Annual CDR capacity of **~3’000 tons CDR per year**

Located in **Iceland**

Powered 100% by **geothermal energy**

CO_2 permanently stored underground through **mineralization**

Currently in construction: Mammoth plant

Mammoth, Climeworks' newest and largest DAC+S plant with **annual CDR capacity of ~28'000 tons per year** (nameplate CO_2 capture capacity of 36'000 tons per year)

The construction is expected to last 18-24 months before **operations start in 2024**.

- Jun 2022: **Groundbreaking** in Iceland.
- Dec 2022: **Construction of main hall** completed.

With capacity increase, costs will be reduced based on 4 pillars

Reduce cost of Climeworks product and plant			Secure best sites globally
Scale up plant size	**Develop technology & product**	**Replicate & learn**	**Low-cost carbon-free energy & storage**
• Reduce specific **CAPEX of central DAC plant** • Reduce specific **operation & maintenance cost**	• Increase **specific throughput** (t CO_2 per intake area) • Reduce **energy consumption** (kWh per t CO_2) • Improve **sorbent lifetime**	• Reduce **CAPEX** through volume and value engineering • Maximize **CDR production efficiency** (t CDR produced per t CO_2 captured)	• Reduce **energy purchasing cost** • Reduce **energy grey emissions** • Reduce **storage cost**

Methodology: CDR cost must refer to net CO_2 removed from the atmosphere

Cost / **Ton CDR** = **Total cost** / **Tons of CDR produced**

Total cost

Cost of CDR production / DAC+S split into key cost buckets:
- CAPEX
- Energy cost
- Sorbent cost
- Operation & maintenance (O&M) expenses
- Storage cost
- Overhead cost (SG&A)
- (Subsidies)

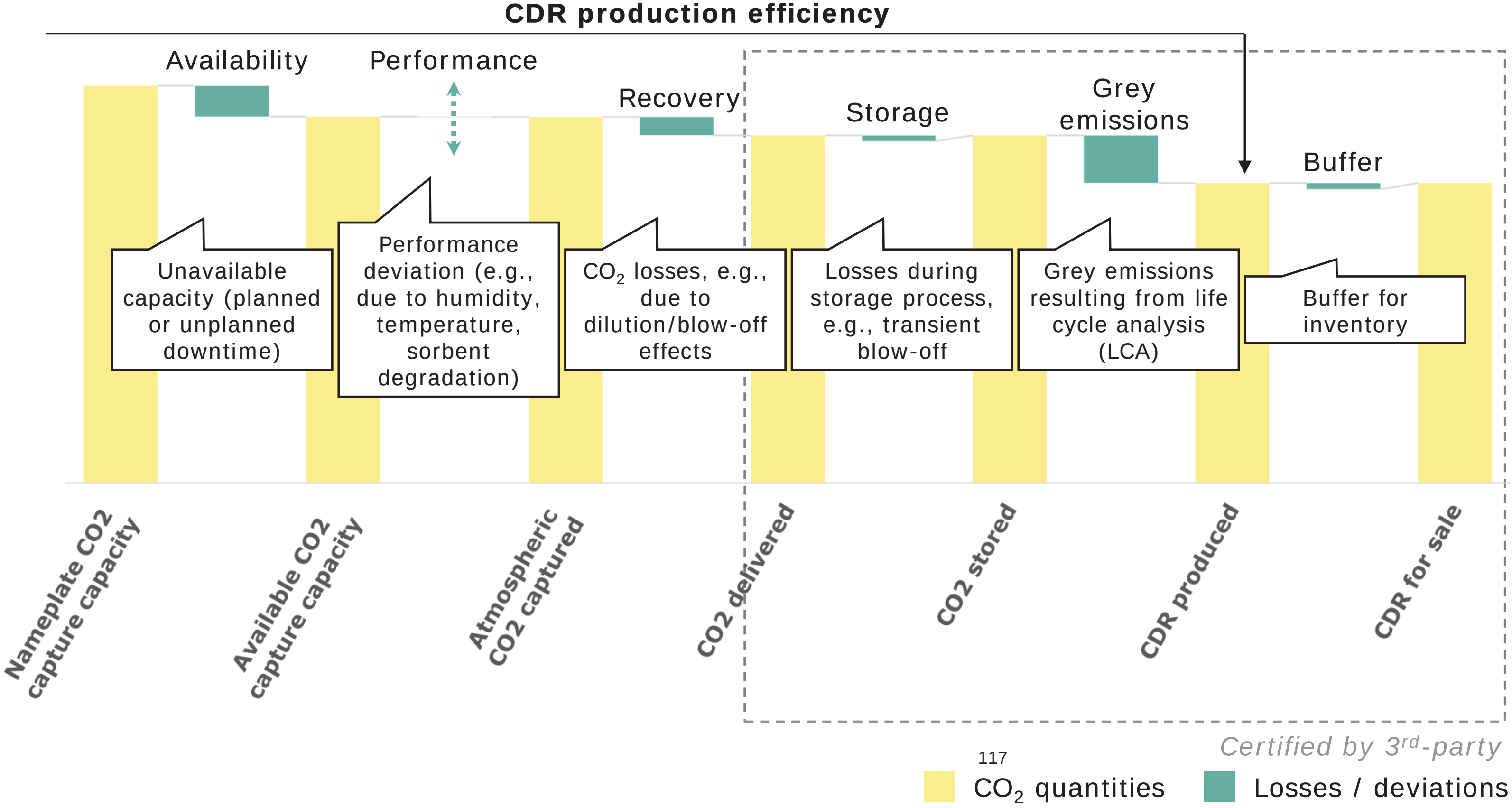
Tons of CDR produced

CO_2 stored, calculated from CO_2 captured net of any losses and grey emissions originating from:
- Plant construction and dismantling
- Sorbent production, transport, and disposal
- Electricity generation
- Heating and cooling
- Water use
- Storage

All reported costs are related to net CO_2 removed from the atmosphere, accounting for all losses and grey emissions incurred during plant construction, operation, and dismantling

Real-world operations brought numerous learnings, data and a clear identification of optimization levers

CDR produced is lower than the nameplate CO_2 capture capacity, as determined by a waterfall of losses and deviations



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As for any industrial scale manufacturing, **availability**, **performance**, and **recovery** have direct impact on CDR cost

What needs to happen to achieve 1 Gt+ production capacity

1	**Commercial**	• **Early sizeable CDR purchases** (~10Mt in 2030, 1Gt+ in 2050) • Willingness to pay **adequate price** for high-quality CDR • **Long-term CDR offtake agreements** (>10 years)
2	**Policy**	• **Government subsidies** (similar to DAC HUB and 45Q in the US) • **Policy frameworks** differentiate between avoidance and removal
3	**Project development**	• **Sites with sufficient storage capacity** • **Renewable energy** available in large quantities
4	**Technology**	• **Low-cost, high-performing sorbent materials** with high stability and fast kinetics • **CAPEX reduction through design for volume manufacturing** of modularized products
5	**Financing**	• **Low financing costs** (WACC<7%) achievable for large-scale projects • **3rd party funding** available in sufficient amounts

Thoughts on the future of DAC

1

DAC is central to enable a net-zero world

Reducing CO_2 emissions must be the number 1 priority in the fight against climate change

Beyond emission reduction, **CDR will be required at Gt-scale to reach a net-zero world.**

DAC can lead the way to large-scale CDR

2

DAC can reach competitive cost-levels when scaling beyond multi-Mt scale

Current costs are not representative and largely not understood since they are at the **beginning of the scale-up curve**

DAC is already cost competitive for ~20% of today's emissions that have abatement costs > USD 1'000/t CO_2[1]

3

DAC maturation and cost reduction happens in the field

Solid technology is required that can withstand the forces of outdoor conditions and will mature over several learning cycles

The DAC market needs to **get started today to enable net-zero tomorrow**

1. Source: Goldman-Sachs 2022 carbon abatement curve

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3.2. Direct air capture case studies

Tim Fout (DOE/NETL):

Direct Air Capture Case Studies

Tim Fout[1], Alex Zoelle[2], Sally Homsy[2], Jessica Valentine[2], Naksha Roy[2], Aaron Kilstofte[2], Mike Sturdivan[2], Mark Steutermann[2], Mark Woods[2]

[1]NETL, [2]NETL Support Contractor

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DISCLAIMER

Attribution

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Outline

- Motivation
- Sorbent Case Study
  http://netl.doe.gov/projects/files/DirectAirCaptureCaseStudiesSorbentSystem_070822.pdf
  - Design Basis
  - Performance Results
  - Cost Results
  - Sensitivity Analysis
- Solvent Case Study
  - Overview

Motivation

Justification

- DAC is one of several Negative Emissions Technologies (NET) currently of interest
- NETL can leverage previous experience in carbon capture to contribute to this emerging field
- Evaluation of a monolith sorbent structure provides researchers with a benchmark structure for the evaluation of their technology through TEA assessment and the determination of performance and cost targets.

Objectives

- Develop and assess a sorbent-based direct air capture (DAC) system that uses a monolithic sorbent structure

- Evaluate and assess solvent-based DAC available in literature and DOE project Reports

DAC Sorbent System
Design Basis

Site Characteristics

Parameter	Value
Location	Greenfield, Midwestern U.S.
Topography	Level
Size (DAC), acres	52
Transportation	Rail or Highway
Water	50% Municipal and 50% Ground Water

Parameter	Midwest ISO		
	Bituminous Baseline Rev4[1]	Direct Air Capture	
Elevation, m (ft)	0 (0)	0 (0)	
Barometric Pressure, MPa (psia)	0.101 (14.696)	0.101 (14.696)	
Average Ambient Dry Bulb Temperature, °C (°F)	15 (59)	15 (59)	
Average Ambient Wet Bulb Temperature, °C (°F)	10.8 (51.5)	10.8 (51.5)	
Design Ambient Relative Humidity, %	60	60	
Cooling Water Temperature, °C (°F)[A]	15.6 (60)	15.6 (60)	
Air composition based on published psychrometric data, mass %[2]			Air composition, mole %
N_2	75.055	74.983	77.243
O_2	22.998	23.050	20.784
Ar	1.280	1.272	0.919
H_2O	0.616	0.633	1.014
CO_2	0.050	0.062	0.040 (403.9 ppmv)
Total	100.00	100.00	100.00

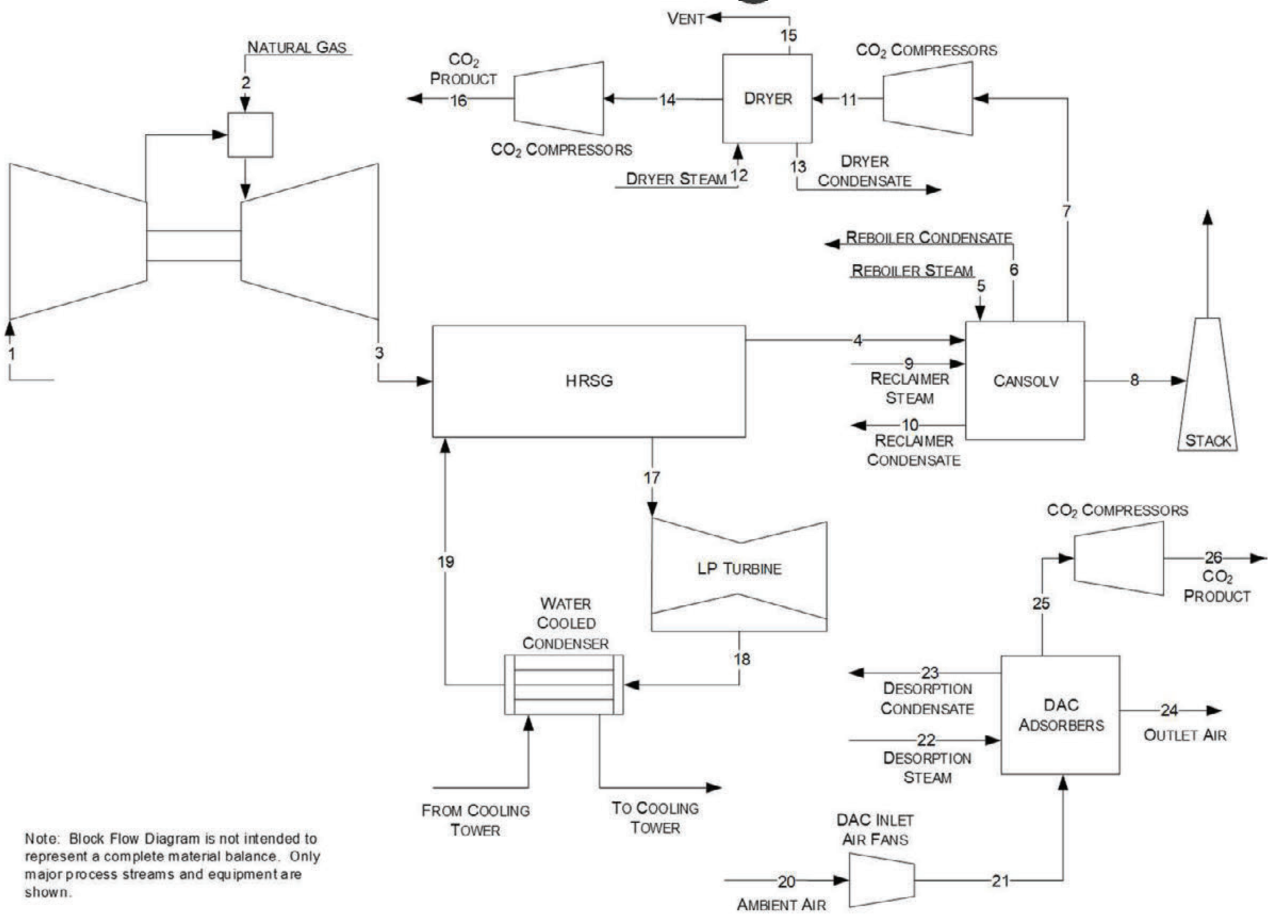
[A]The cooling water temperature is the cooling tower cooling water exit temperature. This is set to 8.5°F (4.8°C) above ambient wet bulb conditions in International Organization for Standardization (ISO) cases and 11°F (6.1°C) otherwise

[1]*R. James, A. Zoelle, D. Keairns, M. Turner, M. Woods, N. Kuehn "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," National Energy Technology Laboratory, Pittsburgh, September 24, 2019.*
[2]*Universal Industrial Gases, Inc., Psychrometric Calculator Properties of Air, http://www.uigi.com/air.html*

Case Matrix

- **Case 0B**
  - Monolithic DAC Sorbent System with NGCC supplied power and steam
  - 90% Post Combustion Capture on NGCC
  - Sized to account for 100,000 tonnes CO_2 / year net removed from atmosphere
- **Case 0B-EB**
  - Monolithic DAC Sorbent System with Electric Boiler for steam
  - Carbon footprint of electricity considered to be zero
  - Included in report but not highlighted due to time
- **Case 0 and 0-EB**
  - Fixed bed DAC Sorbent Systems
  - High pressure drops led to high costs and very un-optimal results
  - Included in the report appendix for reference

DAC Case 0B Block Flow Diagram



Note: Block Flow Diagram is not intended to represent a complete material balance. Only major process streams and equipment are shown.

Source: NETL

Simplifying Assumptions

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- **Absorber vessel outlet air exits w/o stack or dispersion considerations**
- **Assumed to be compliant with Effluent Limitation Guidelines**
  - Produced water from DAC or NGCC w/capture
- **Non-type NGCC Turbine used**
  - "Rubber" turbine
- **Single reciprocating compressor for CO_2 compression**
- **Scaled NGCC w/ 90% capture for steam and electricity use**

*R. James, A. Zoelle, D. Keairns, M. Turner, M. Woods, N. Kuehn "Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity," National Energy Technology Laboratory, Pittsburgh, September 24, 2019. https://netl.doe.gov/projects/files/CostAndPerformanceBaselineForFossilEnergyPlantsVol1BitumCoalAndNGtoElectBBRRev4-1_092419.pdf

DAC System Assumptions

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Parameter	Assumed Value
Adsorber Vessel Type	Monolith
DAC Net Capture Rate, tonne CO_2/yr	100,000
Plant Capacity Factor, %	85
CO_2 Product Purity	Meets pipeline specification without purification
DAC System Pressure Drop, psi (in. H_2O) [A]	0.3 (7.78)
DAC System Capture Fraction	0.6
DAC Sorbent Desorption Temperature, °C (°F)	100 (212)
DAC Sorbent Regeneration Energy, GJ/tonne CO_2 (Btu/lb CO_2)	4.3 (1,847)
DAC Sorbent Adsorption Temperature	Ambient
DAC Sorbent Adsorption Capacity, mol CO_2/kg (lb CO_2/lb sorbent)	1.2 (0.053)
DAC Sorbent Lifetime, years	0.5
Sorbent Cost, \$/ft^3 (\$/lb)	4.0 (0.09)

[A] Includes pressure drop across ducting and DAC vessels

DAC Sorbent Configuration

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	Case 0B (Monolith)
Superficial Velocity (ft/s)	8.18
Bed Depth (ft)	2
Cell Diameter (ft)	0.00479[1]
Bed Pressure Drop (Pa)	625
System Pressure Drop, including Ducting (Pa)	1,935
Reynold's Number	249
Vessel Diameter (ft)	60
Number of Vessels	20
Sorbent Loading (gmol/kg sorbent)	1.2
Sorbent Density (lb/ft³)	24
Adsorption Time (hr)	3

Steady, laminar flows

$$-\Delta p_s = \frac{32 \Delta L \, \overline{V} \mu}{g_c D^2}$$

Δp_s = pressure drop
ΔL = column length
V = superficial fluid velocity
μ = viscosity
g_C = 32.174 ft-lb/lbf-s2
D = channel diameter

- The cell diameter was used from previous published literature that looked at monolithic sorbent air contacters[1]
- Hagen-Poiseuille equation was used to back calculate the necessary parameters for a bed pressure drop of 625 Pascals

U.S. DEPARTMENT OF ENERGY

1. Rezaei, F., & Webley, P. (2009). Optimum structured adsorbents for gas separation processes. Chemical Engineering Science, 64(24), 5182-5191.

DAC Sorbent System Performance Results

Performance Results Summary

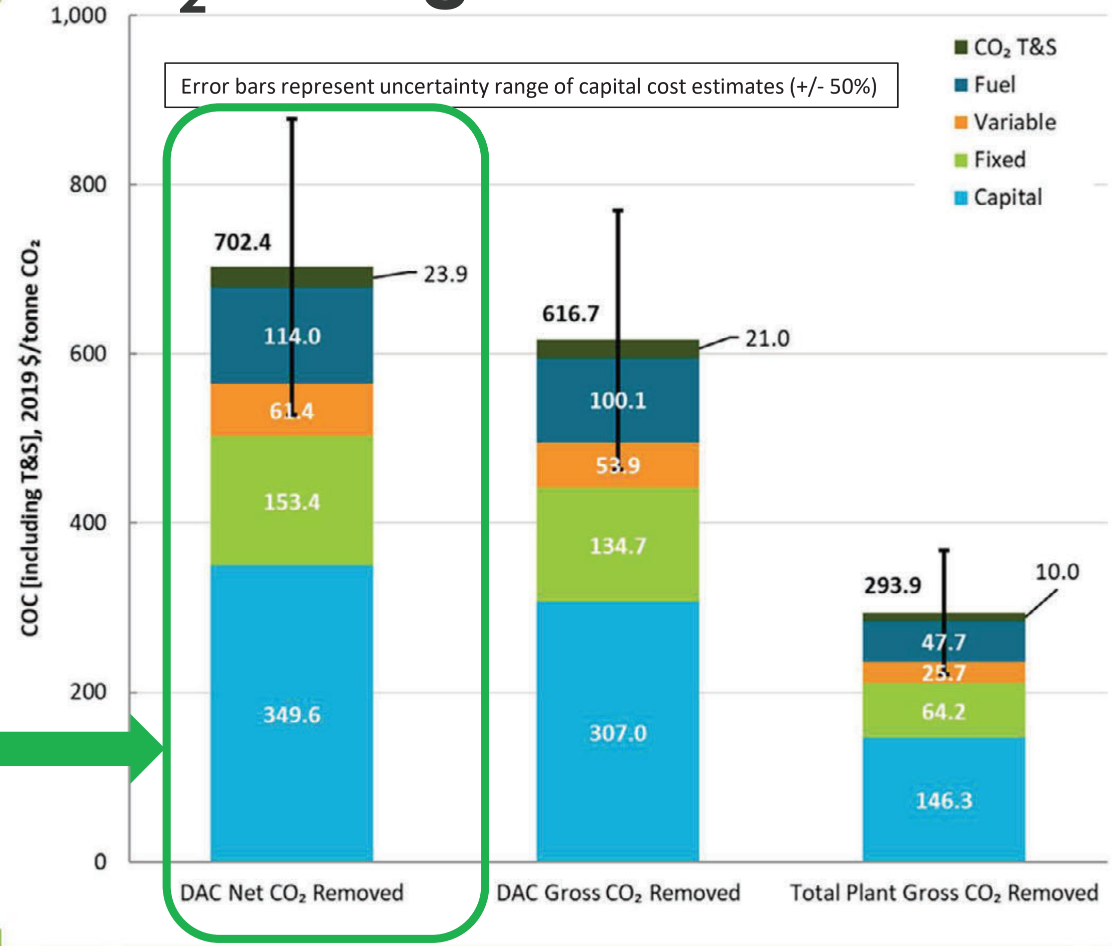
DAC Case 0B Performance Summary	
Combustion Turbine Power, MWe	36
Steam Turbine Power, MWe	2
Total Gross Power, MWe	**37**
Auxiliary Loads	
NGCC CO_2 Capture/Removal Auxiliaries, kWe	800
NGCC CO_2 Compression, kWe	1,290
DAC Air Fans, kWe	32,810
DAC CO_2 Compression, kWe	1,690
Balance of Plant, kWe	780
Total Auxiliaries, MWe	**37**
Net Power, MWe	**0**
Natural Gas Feed Flow, kg/hr (lb/hr)	6,988 (15,405)
HHV Thermal Input, kWt	101,503
LHV Thermal Input, kWt	91,617
CO_2 Balance	
NGCC Flue Gas CO_2 Captured, tonne/yr	125,090
DAC CO_2 Removed from Air (Gross), tonne/yr	113,900
NGCC Flue Gas CO_2 Emitted to Air, tonne/yr	13,900
Net CO_2 Removed from Air, tonne/yr	**100,000**

DAC Sorbent System Cost Results

Special Considerations On Reported Costs

- **Capital Cost Estimates**
  - DAC -50/+50, Class 5 AACE Classification
  - Concept Screening
- **Not FOAK or NOAK Costs**
  - Consistent methodology applied as for commercial systems
  - Detailed depiction of assumptions and design
  - Capital costs and scaling parameters for the DAC system components were developed by Black & Veatch using in-house cost estimating references
- **Other Factors**
  - Site/project specific (Scale, Capacity Factor, Financing, Labor Rates, Regulations, etc.)
- **Future Cost Trends**
  - Effect of R&D

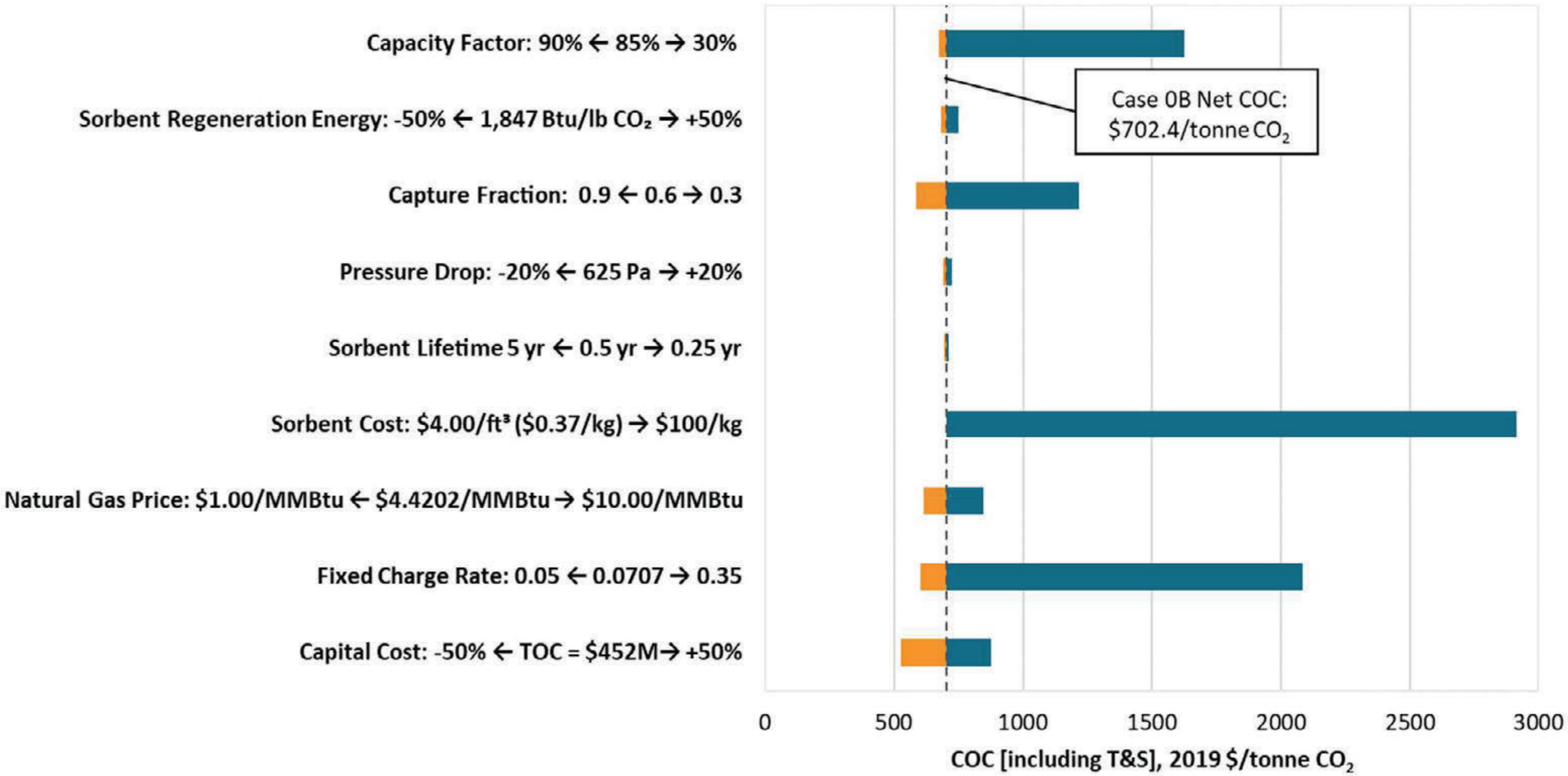
Breakeven CO_2 Selling Price



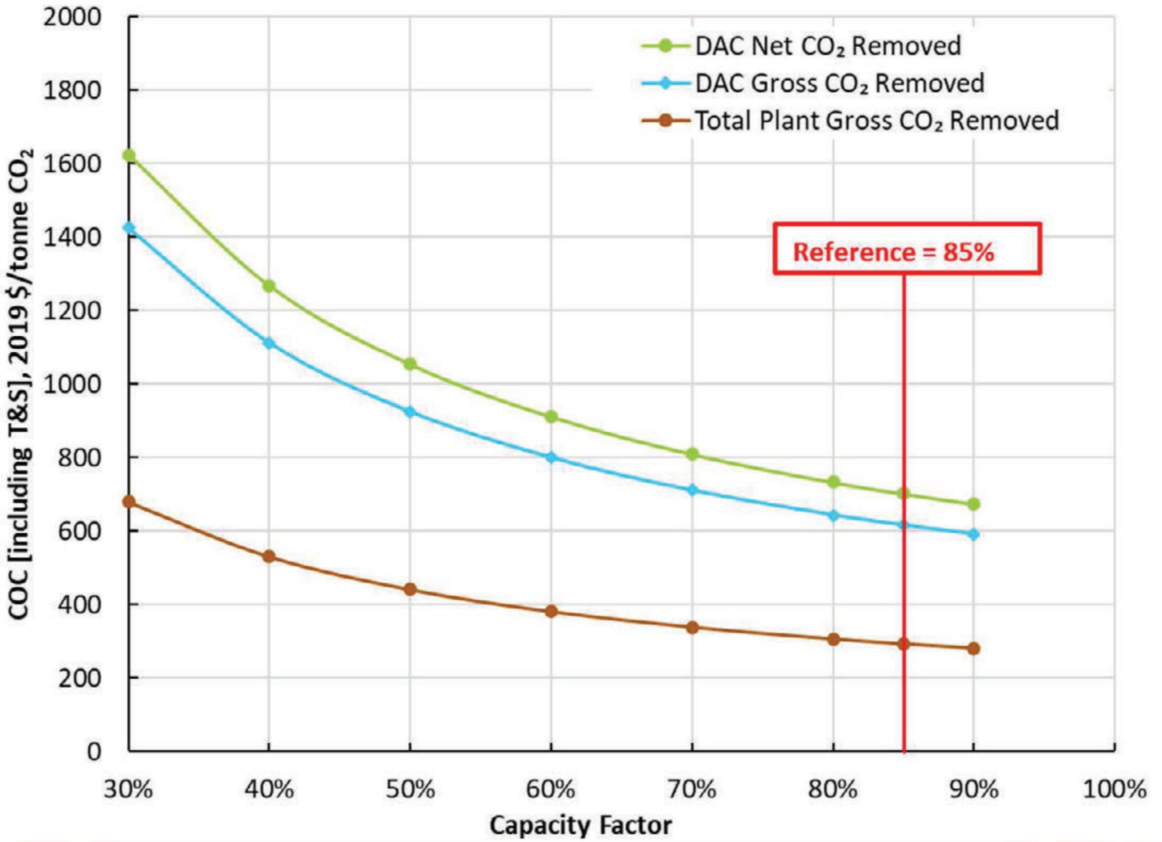
Preferred Metric for DAC

DAC Sorbent Sensitivity Analysis

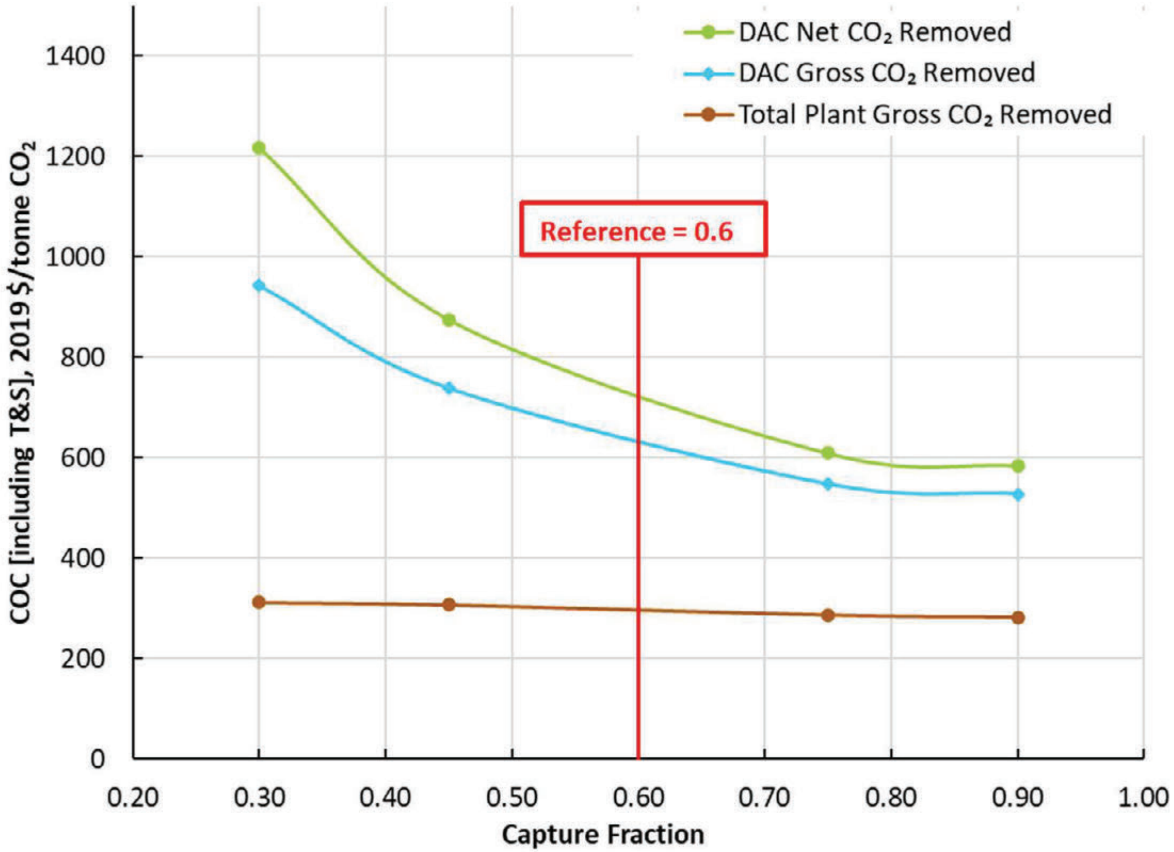
Sensitivity Analysis Summary



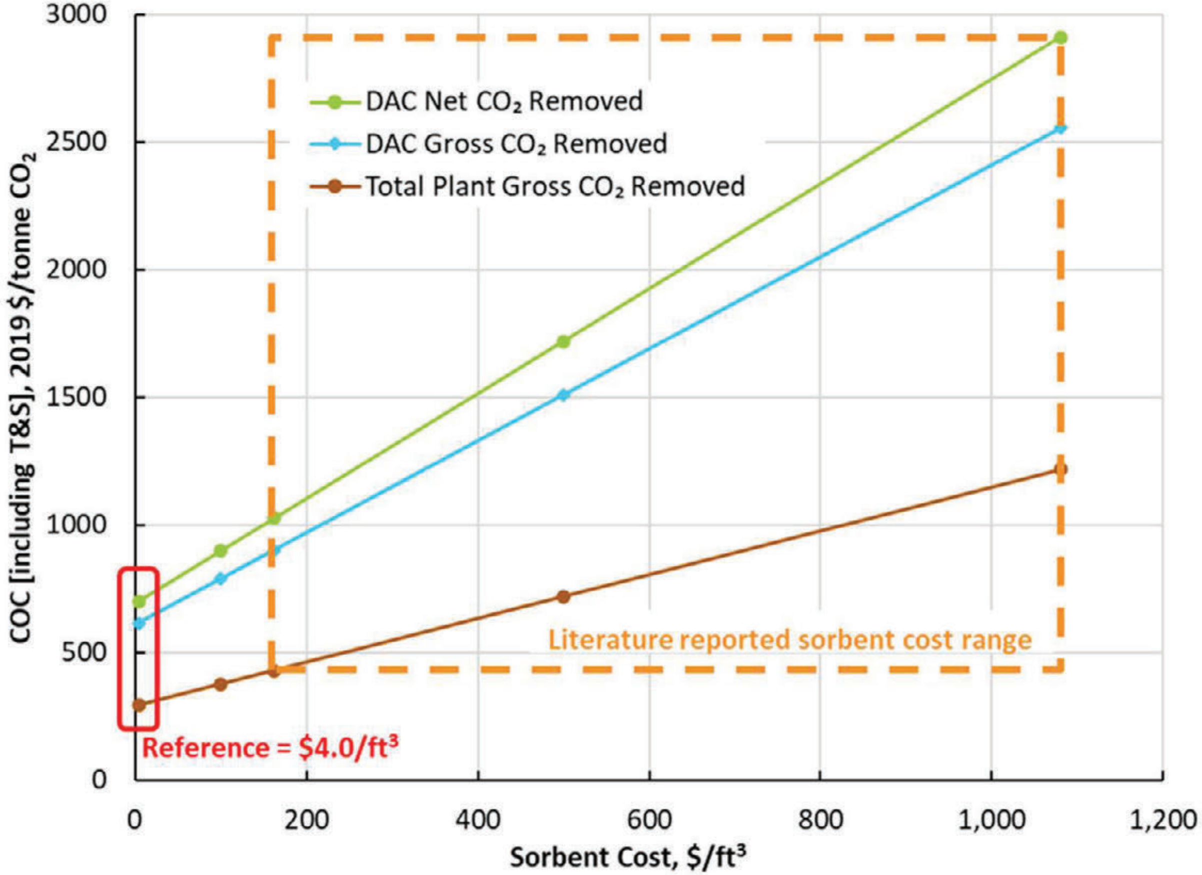
Sensitivity – Capacity Factor



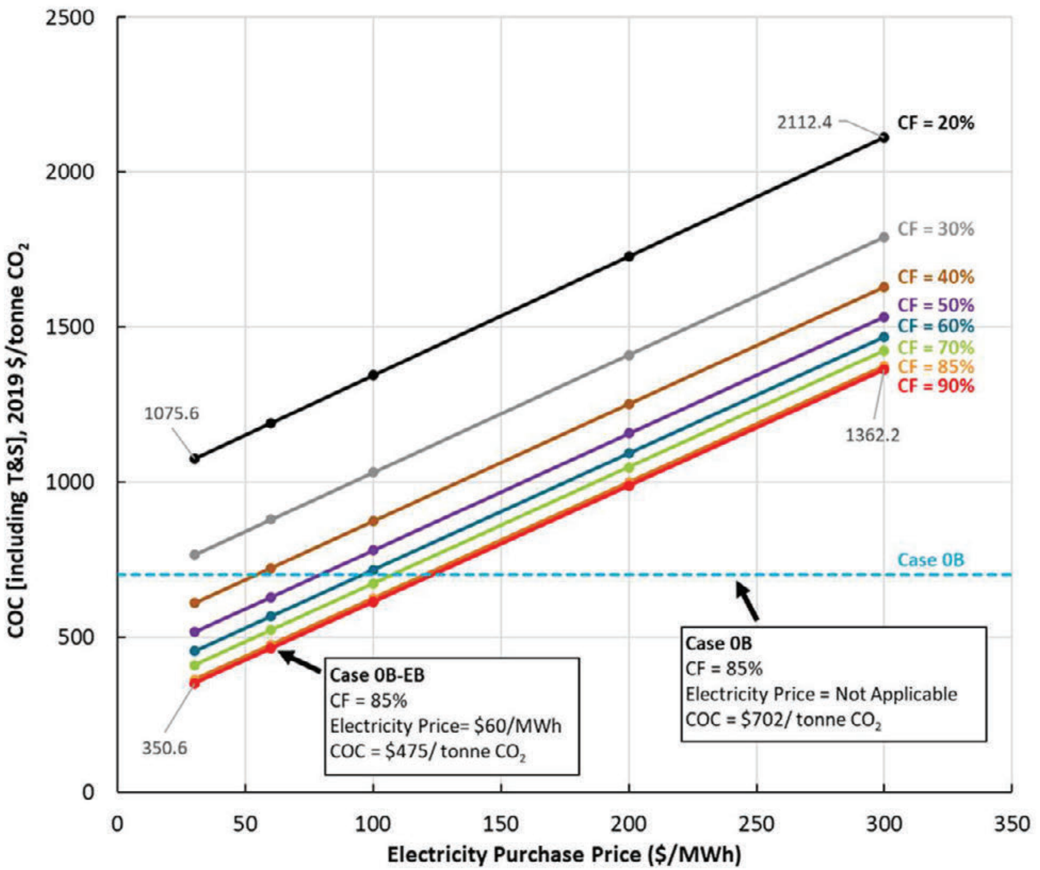
Sensitivity - Capture Fraction



Sensitivity - Sorbent Cost



Electric Boiler Sensitivity

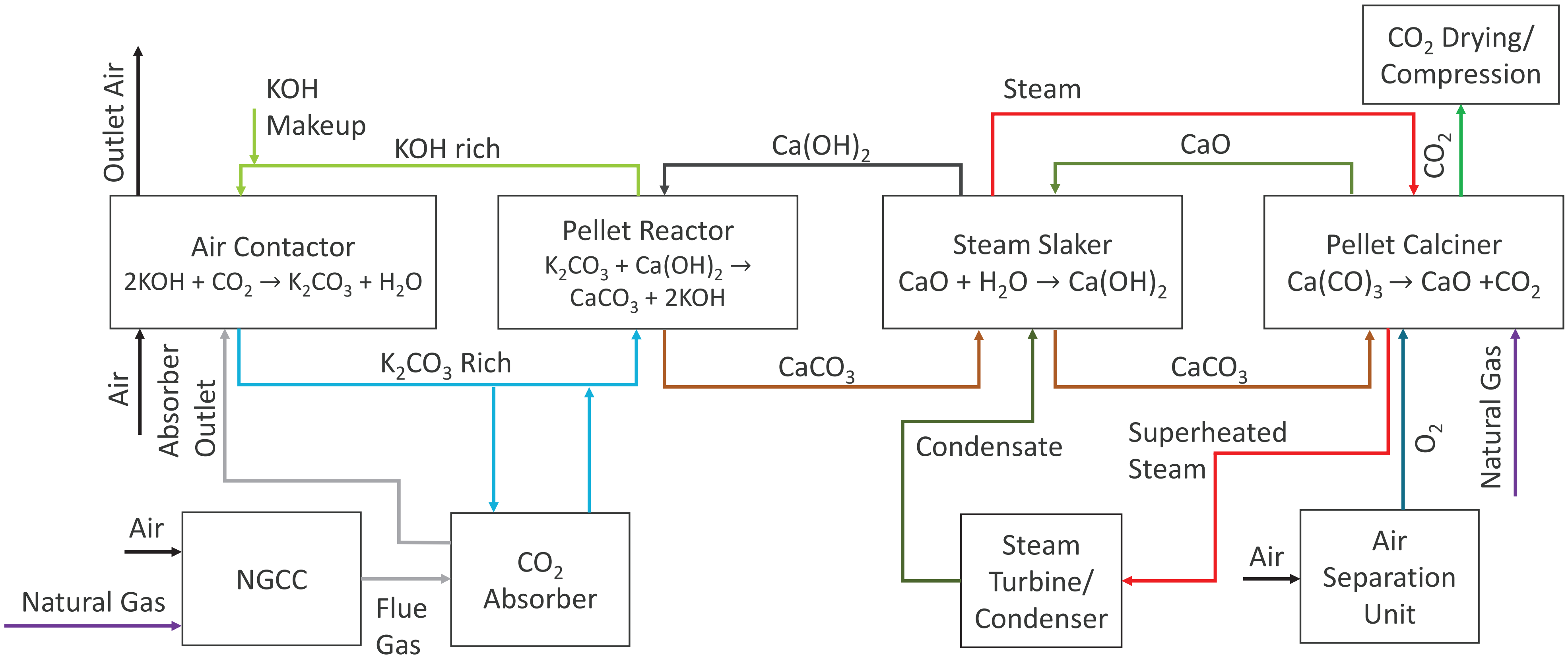


IMPORTANT ASSUMPTIONS

- Cost of Capture in Electric Boiler Sensitivity DOES NOT include carbon footprint of electricity used
- COC shown in NOT equivalent to COC_{net} unless electricity is 100% carbon free

DAC Solvent Study

Simplified Block Flow Diagram



DAC System Assumptions

Parameter	Assumed Values
Air Contactor	
CO_2 Capture Percentage, %	74.5
AC Pressure Drop, psi (in. H_2O) [A]	0.013 (0.36)
Flue Gas CO_2 Absorber	
Absorber Pressure Drop, psi (in. H_2O)	1.5 (42.8)
CO_2 Capture Percentage, %	90
Pellet Reactor	
Conversion of $Ca(OH)_2$, %	100
Steam Slaker	
Conversion of CaO, %	85
Oxy-Fired Calciner	
Excess Oxygen, %	4.1
Temperature, °F (°C)	1652 (900)
Low Pressure ASU	
O_2 Product Pressure, psi (kPa)	17 (120)

[A]Includes pressure drop across ducting and DAC vessels

Parameter	Assumed Values
General Plant Characteristics	
DAC Net Capture Rate, tonne CO_2/yr	903,970
Plant Capacity Factor, %	85
CO_2 Product Purity	95.53% CO_2 1.79% O_2 2.61% N_2 0.05% H_2O

- The CO_2 product purity is assumed based on CE stream data; it does not meet CO_2 product purity O_2 concentration specifications (10-100 ppmv depending on end use[1,2])
- A sensitivity case includes a CO_2 purification unit (CPU) to account for this

U.S. DEPARTMENT OF ENERGY

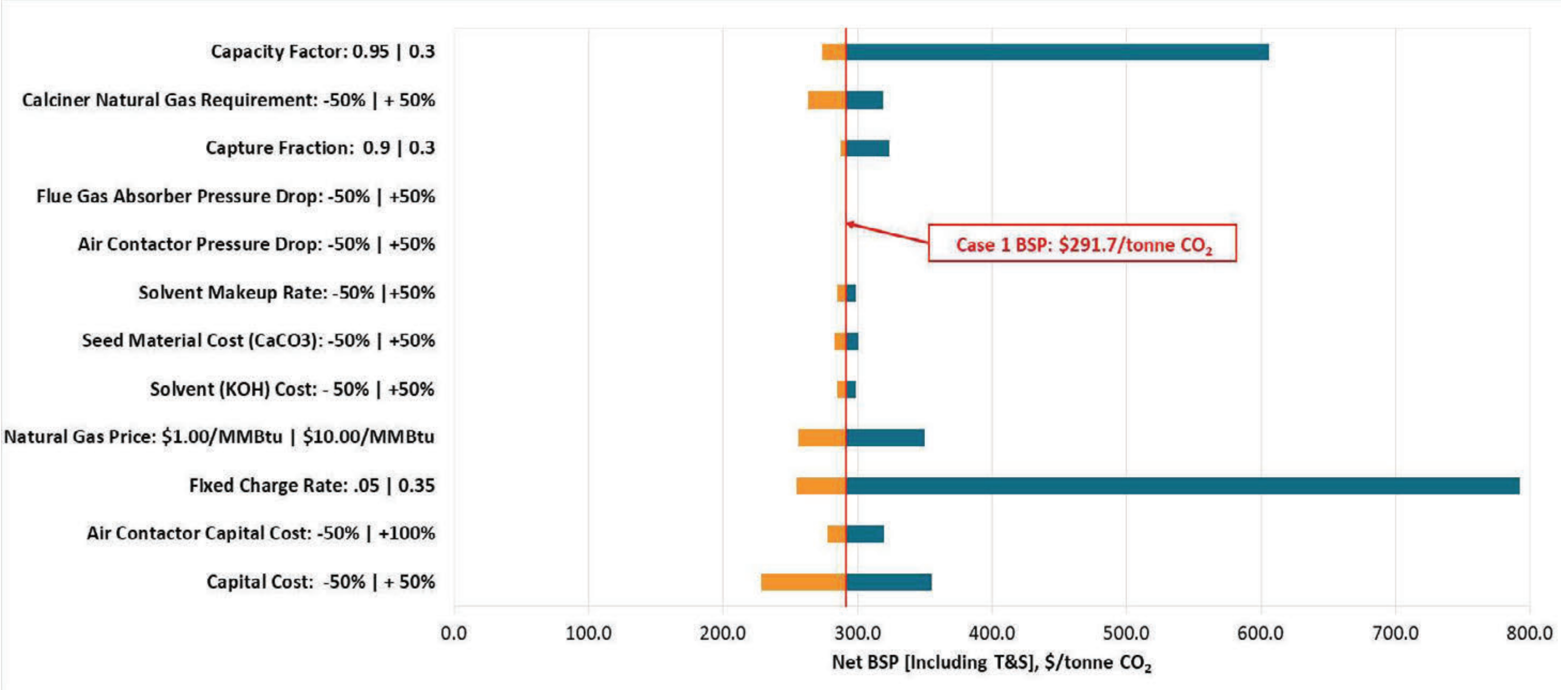
[1]NETL, "Quality Guidelines for Energy System Studies: CO_2 Impurity Design Parameters," DOE, January 2019.
[2]Internal discussion with the Team KeyLogic Subsurface team, December 2019.

Solvent based DAC Sensitivities

Single Variable

Results

- The sensitivity analysis did not identify any key process parameters that could have significant impact on the results, if improved
- Financial parameters like fixed charge rate have a significant impact on results, but the risk associated with this technology, coupled with an uncertain future market, makes it difficult to identify the appropriate financial structure



Future Work

- Use of an actual NGCC turbine frame size
- Adjustment of sorbent cost to a cost that is representative of SOTA DAC
  - Rerun of sensitivities
- Determination of performance and cost with specific electricity/carbon footprint profiles
- Integration of DAC study systems with specific alternate energy sources
  - Nuclear
  - Geothermal
  - Solar

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Session 4: Offshore CO_2 Transport and Storage

4.1. South East Asia CO_2 source sink mapping to optimize transport cost using pipelines and ships.

Johannes Kalunka (ExxonMobil)

ExxonMobil

April 2023

South East Asia CO_2 Source Sink Mapping to Optimize Transport Cost Using Pipelines and Ships

Energy lives here™

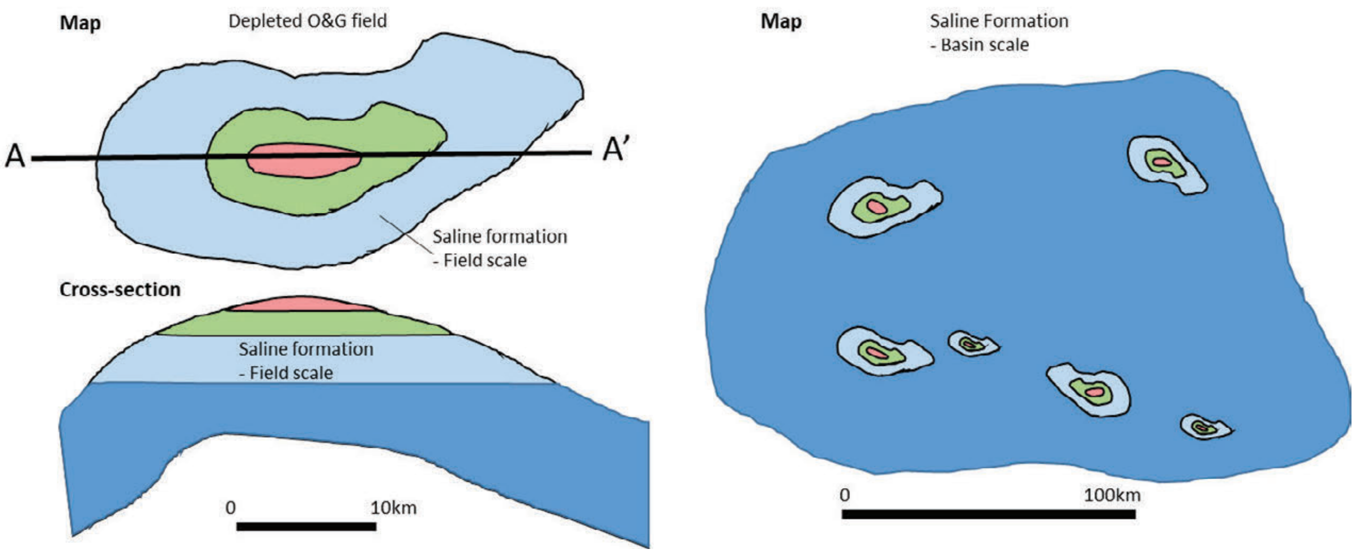
Ganesh Dasari, Adam K Usadi, Stephen A Jones, Jesse W Senkel, Yunyue Elita Li, Abdel Khalek Salah Wissam, Anuar Togabekov, Xuan Wee Tan, Wai Lam Loh, Xiangnan Wang, Jingchen Jiao, Johannes Kalunka

7th IEAGHG CCS Cost Network Workshop, 12 April 2023, Groningen, The Netherlands

Outline

- CO_2 Storage Potential of South East Asia
- South East Asia CO_2 Transport Options
- Source-Sink Mapping
- Storage and Transport Cost Elements
- Summary

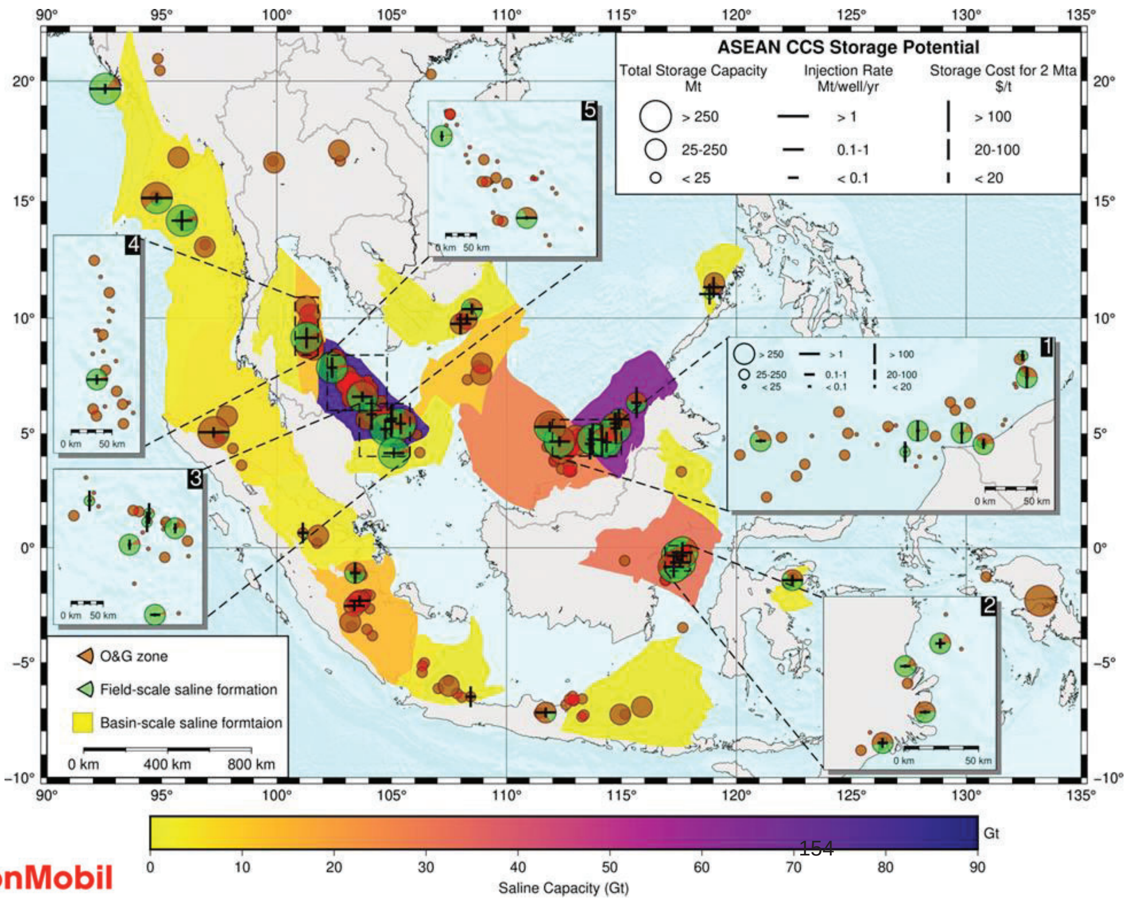
CO_2 Storage Options



Schematic depiction of storage potential in (1) Oil and Gas fields, (2) Saline formations close to fields, and (3) Basin-wide saline formations

ExxonMobil

South East Asia: Storage Potential and Injectivity, and Storage Cost



- SEA CO_2 Storage Potential
  - About 11 GT in depleted fields, 42 GT in field-scale saline formations, 275 GT in basin-wide saline formations
- Injectivity varies from 0.1 to >1.5 MTA/well
- Storage cost varies from <20 $/t to >100 $/t*

* Costs are based on the assumptions stated in the paper; project specific costs will be different

GT = Gigatonnes
MTA =Million Tonnes per Annum

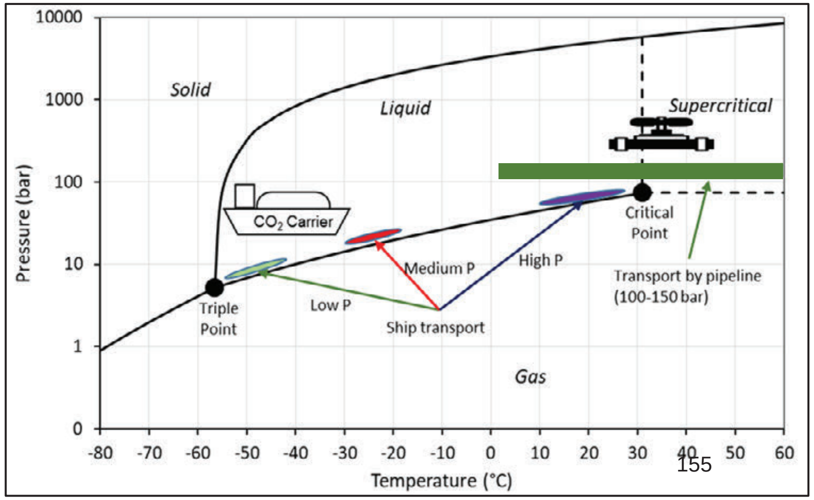
ExxonMobil

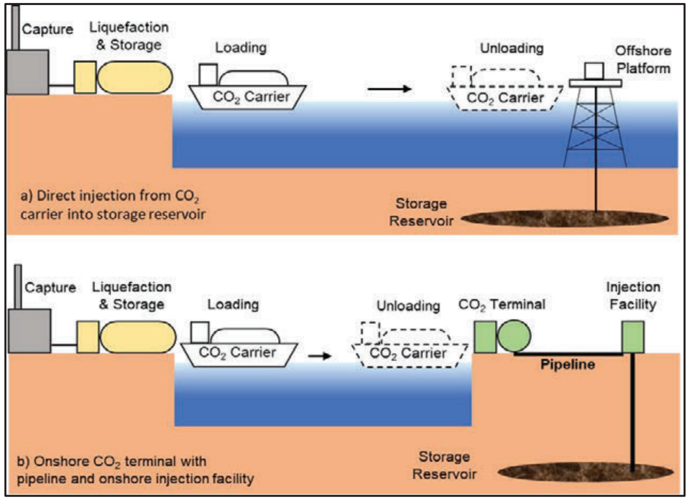
Major Cost Elements of Pipeline and Shipping CO_2 Transport

CO_2

Pipeline route: Compression + Dehydration → Onshore pipeline → Offshore pipeline → Pipeline-to-well connection → Subsurface Storage

Shipping route: Liquefaction + Dehydration → Loading Terminal (pumps, tanks, arms) → Shipping → Offshore/Onshore Storage + Facilities → Subsurface Storage





Unit Cost of Some of the Major Cost Elements

Capacity (MTA)	Unit Cost $/tonne
1	24.4
2	22.3
5	21.8

Cost of compression and dehydration
(National Petroleum Council, 2019)

Capacity (MTA)	Capex (M$)	Opex (M$)/yr	Total Unit Cost $/tonne
1	63	15	20.9
2	87	27	17.6
5	161	63	15.6

Cost of Dehydration and Liquefaction
IEAGHG (2020)

Capex(x) = A*x, where x = distance in km		
Capacity (MTA)	Capex (M$)	Opex (% of Capex)/yr
1	A = 0.5536 M$/km	0.4
2	A = 0.8106 M$/km	0.4
5	A = 1.3417 M$/km	0.4

Cost of onshore pipelines
(National Petroleum Council, 2019)
Offshore pipelines Capex assumed to be 1.5 times

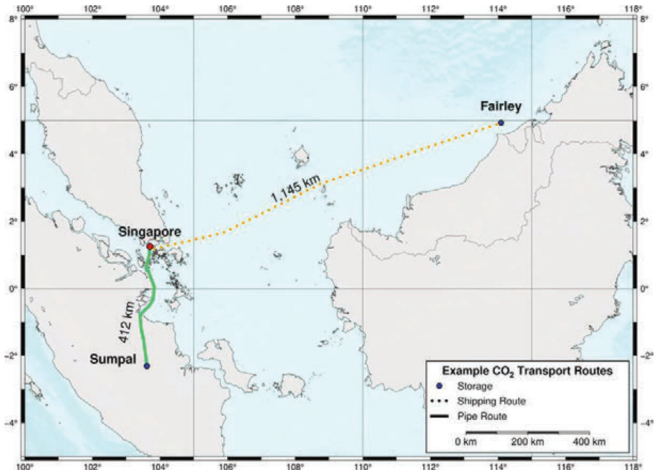
Capex(x) = A*x + B, where x = distance in km		
Capacity (MTA)	Capex (M$)	Opex (M$)/yr
1	A = 0.0696, B = 97.8614	A = 0.0049, B = 6.81
2	A = 0.1428, B = 145.48	A = 0.0100, B = 11.11
5	A = 0.3858, B = 291.77	A = 0.0265, B = 24.20

Cost of shipping based on Element Energy (2018)

Offshore unloading facilities (1, 2, and 5 MTA) cost was taken to be $15.36 $/t based on IEAGHG (2020)

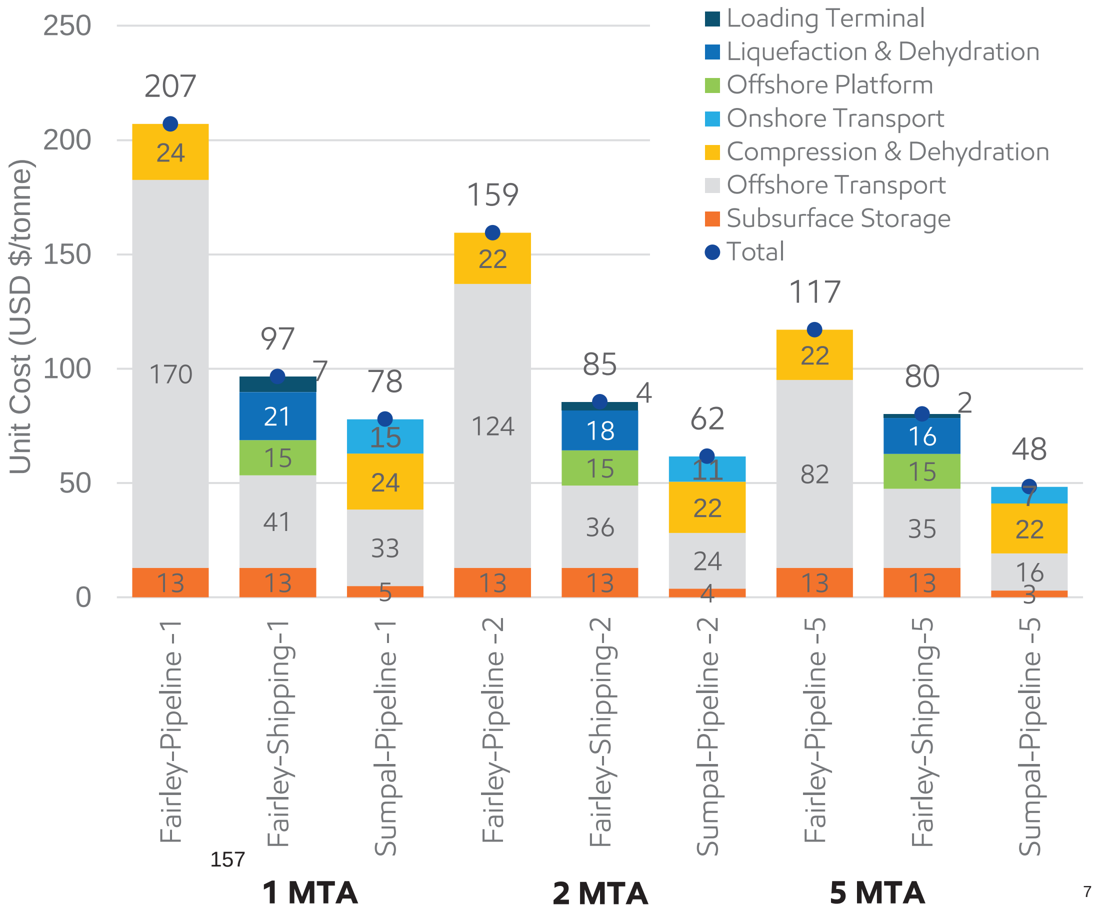
Capex and Opex converted to unit cost using standard project economic models

Example Unit Costs for Transportation and Storage



Example Routings / Routes with Singapore CO2 Source

Comparison: 1,000km circle around The Netherlands



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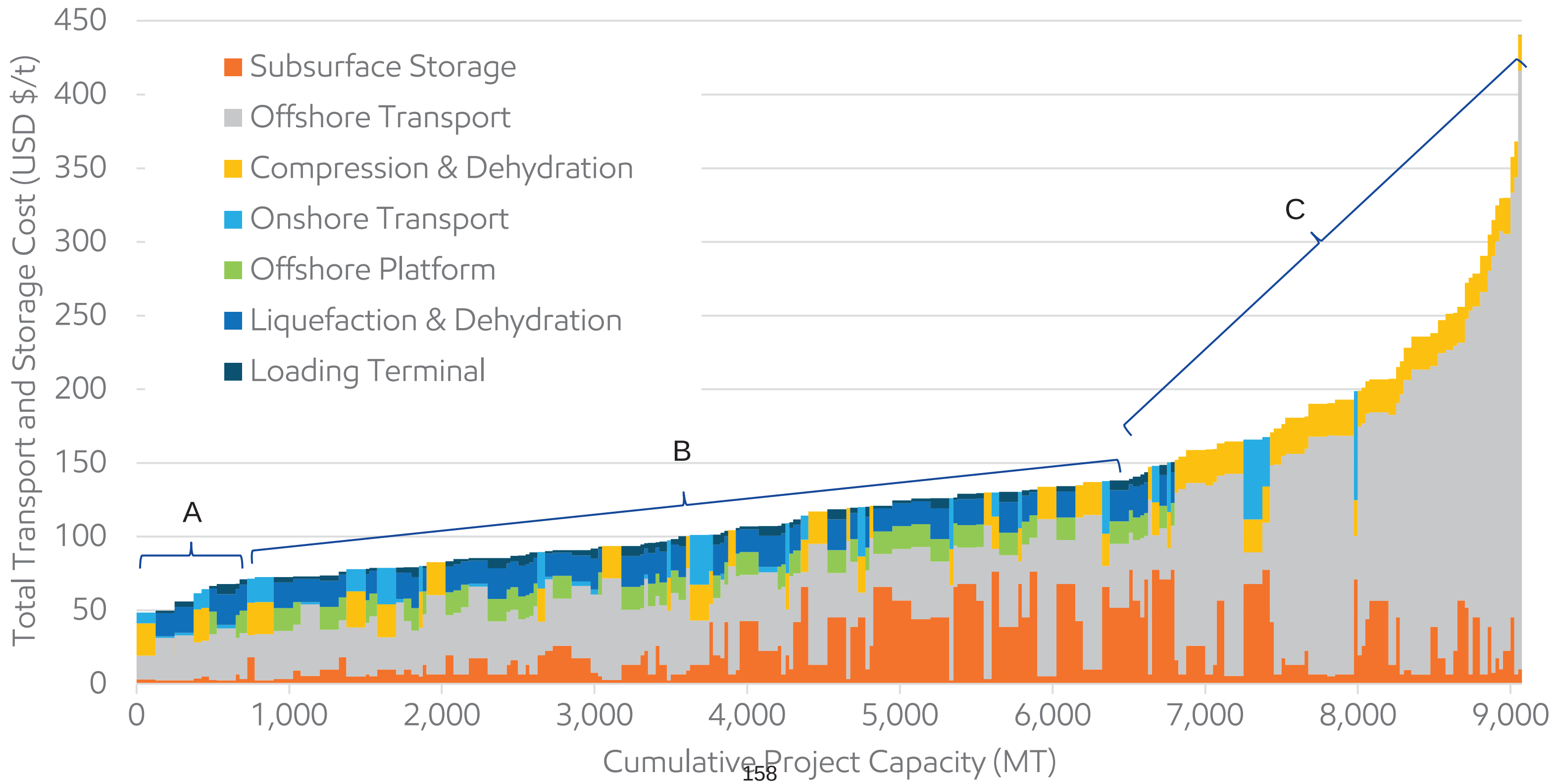
South East Asia CO_2 Transport and Storage Cost Estimates for CO_2 Sources in Singapore



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Group A: \$50/t to \$75/t, Group B: \$75/t to \$150/t, Group C: \$150/t to \$450/t

Summary

- Although this study was based on South East Asia many learnings can be applied to Europe or other similar regions, especially in relation to long distances
- South East Asia has large CO_2 storage potential of about 275 Gigatonnes; Storage potential is unevenly distributed and injectivity varies significantly
- Hubs are needed to optimize the storage and transportation costs given the uneven distribution of sources and variable injectivity
- Total transport and storage cost evaluation at hubs requires careful evaluation of various cost elements of onshore pipelines, offshore pipelines, and/or shipping
- Facilities required at loading and unloading will significantly impact total shipping cost; Cost of shipping depends on project specifics
- For CO_2 sources in Singapore, transport and storage cost may fall into three groups; For first gigatonne T&S cost* may be $50/t to $75/t; for the next three gigatonnes T&S cost may be $75/t to $150/t; and beyond that T&S cost may be >$150/t

* Costs are derived based on the assumptions stated in the paper; project specific costs will be different

4.2. ARAMIS- A large-scale CO_2 transport service enabling offshore storage, *Sander Nijman (Shell) and Boudewijn Reniers (TotalEnergies)*

A large-scale CO_2 transport service enabling offshore storage

Sander Nijman (Shell), Boudewijn Reniers (TotalEnergies)

7th IEA GHG Cost Network Workshop
12-13 April
University of Groningen

Agenda

- Introduction to the Aramis project
  - Aramis as a Project of Common Interest
  - Value chain
  - Timeline
- Transport & Storage Trilemma, Project complexity
- Bundling of service for launching phase
- CCS related subsidy schemes
- SDE++ and related Transport & Storage costs

Open discussion

ARAMIS

About the project

Aramis aims to contribute to the energy transition by offering a large-scale CO_2 transport and storage solution for hard-to-abate industries

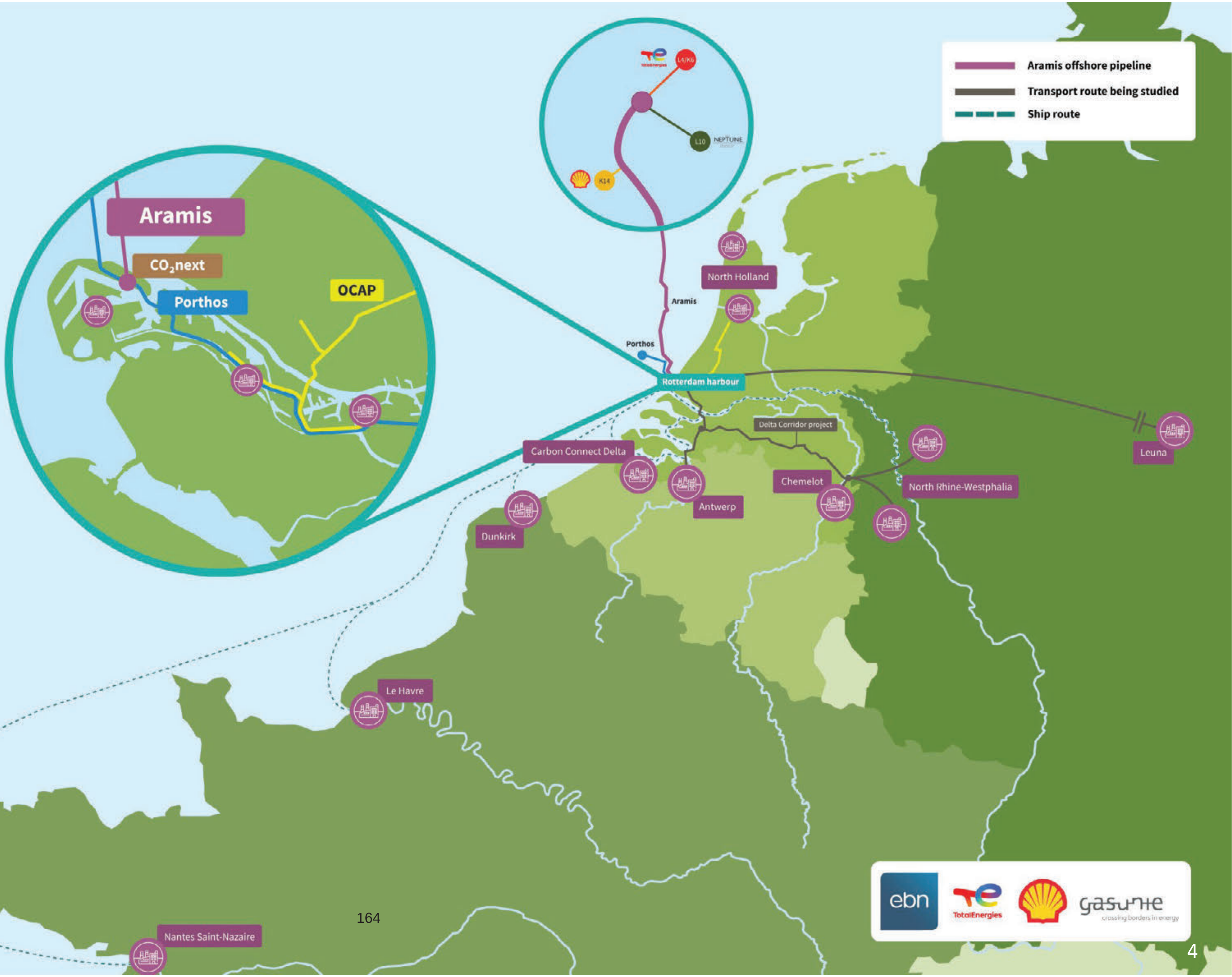
Aramis will construct an **open access** infrastructure with a maximum capacity of ca **22 Mtpa**

EU Project of Common Interest

ARAMIS

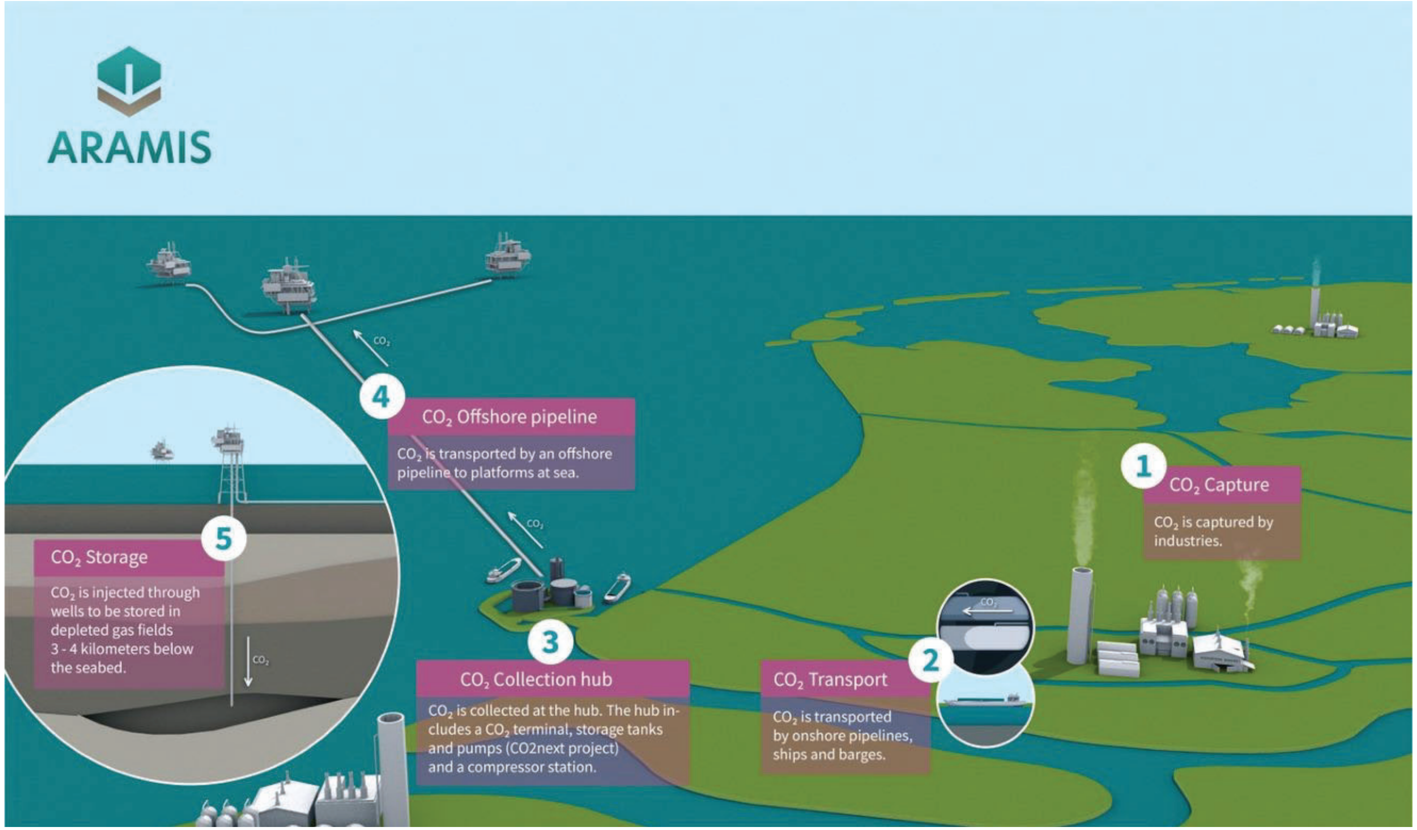
Started as private initiative
- Initial focus on stores
- Public-private cooperation with EBN & Gasunie joining in September 2021: www.aramis-ccs.com

Re-applied for PCI-status under the 6th list
- Members State support (FR, GE,BE, NL)
- Connected to other European CCS initiatives
- Planning to apply for Capex subsidy (CEF) in 2023



ebn TotalEnergies gasunie

Aramis value chain in summary



Capture

- Pre- and post combustion capture

Transport

- Porthos/Delta Corridor onshore pipeline and expansion of Porthos compressor station (Aramis owned compressors)
- Shipping via coasters and barges to a new terminal (CO2next project)
- New offshore pipeline to storage locations (**dense phase**)

Storage

- Depleted gas fields

ARAMIS

Timeline

STEP 1

2019-2021

Feasibility study and setting-up of partnerships. Received EU PCI-status

STEP 2

2022-2024

Design of the concept jointly with emitters and other stakeholders. Apply for CEF subsidies. Aim to start FEED in summer 2023

STEP 3

2025-2026

Construction phase. Modular design for Terminal & Compression. First phase possibly up to 10 Mtpa capacity

STEP 4

End-2027

Go-live. First CO_2 transport & storage (will include a start-up and ramp-up period)

STEP 5

Beyond 2027

Expansion with cross-border CO_2 transport and eventually scale-up to >20 Mtpa after 2030 depending on demand for storage

ARAMIS

Transport & Storage Trilemma, Project complexity

Trilemma

Uncertainties
Costs,
Volumes &
Subsidies

find
balance

Choice
Target
IRR

Customer view
Affordable
Tariff

Assuming that expertise and insight into the construction, exploitation and maintenance of terminal, compressor stations, offshore pipelines, shipping and storage operation is in place

Fee (tariff)

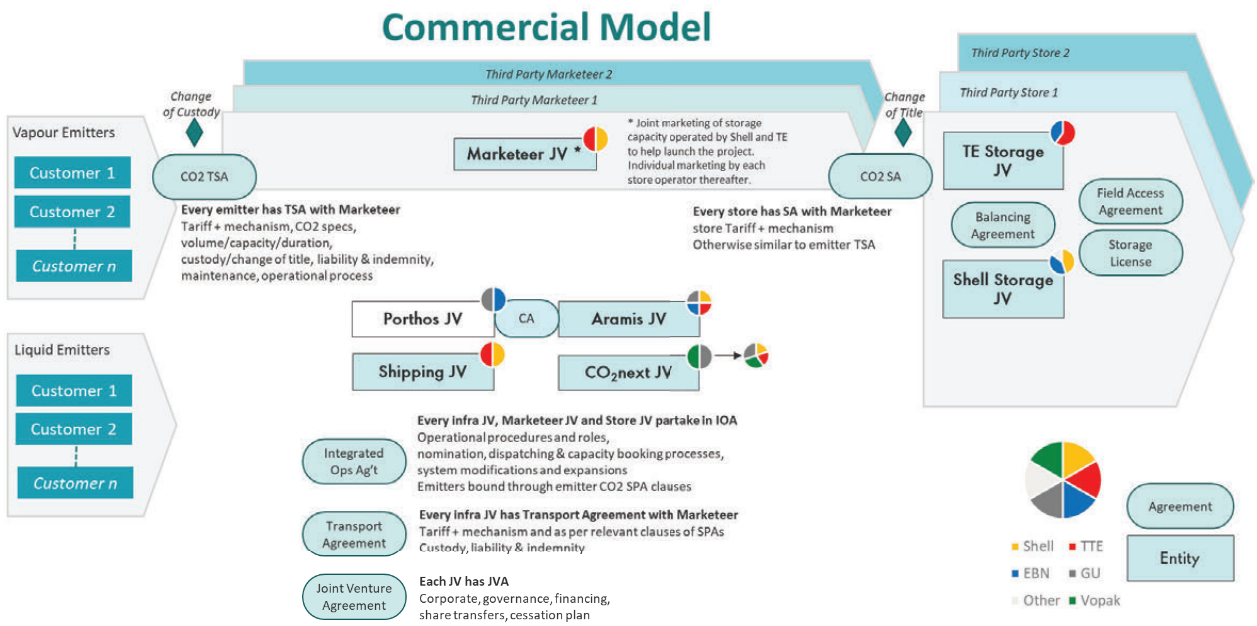
For the T&S value chain a fee needs to be offered to the market taking into consideration:

- Needs to affordable by customer
- Project return and return on equity (full chain)
- Residual value after 15 yrs (duration of SDE++)
- Risk premiums and insurance (contractual conditions)
- Significant cost components
- Cost and benefit of open access, to enable additional CCS parties using the infrastructure

Joint marketing for the launching phase in place to ensure minimum volume for an FID-able project

Bundled Transport & Storage Service for launching phase

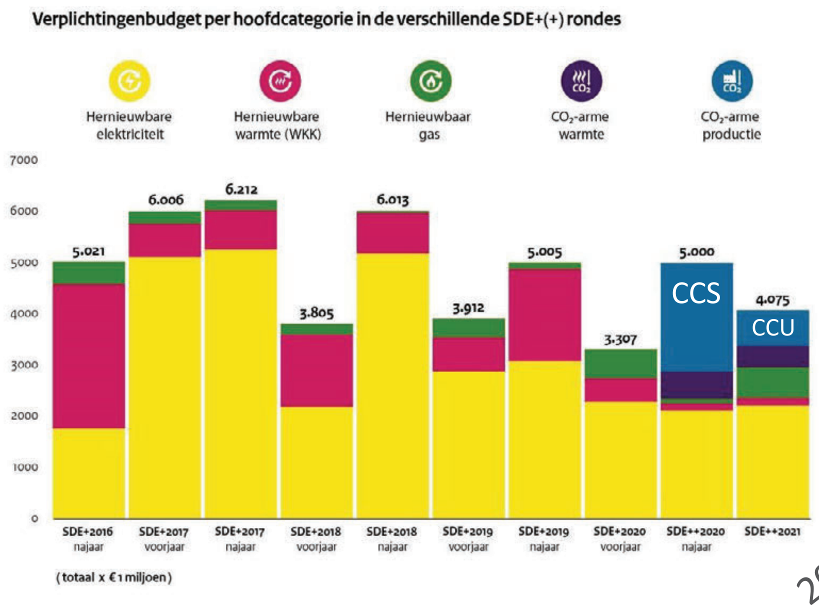
- Aramis is quite a complex aggregation of many 'value chain parties' (VCP)
- Each VCP has its own perception on:
  - Governance
  - Technical
  - Commercial & Business
  - Contracting & Procurement
  - Stakeholder Management, Public affairs, Communication and permitting
  - Venture set up

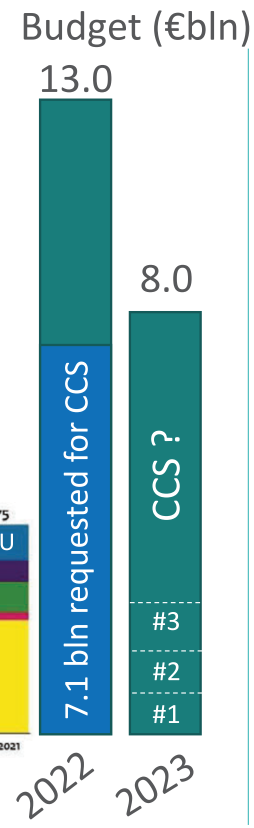


- Bundled connecting of emitters with storage is key to success
  - Alignment of timing, risks, liabilities, capacity and costs of full value chain
  - There are too many emitters and too many VCP to do this unbundled in the development phase
  - Key is that bundled T&S services are offered on a non-discriminatory and transparent way with clear customer selection criteria

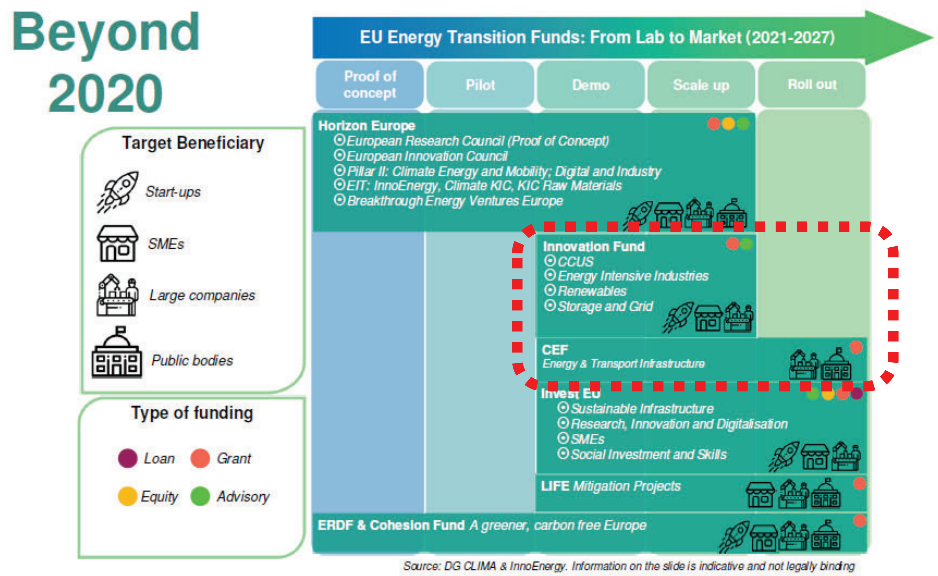
Overview of the main CCS-related subsidy schemes

National: SDE++





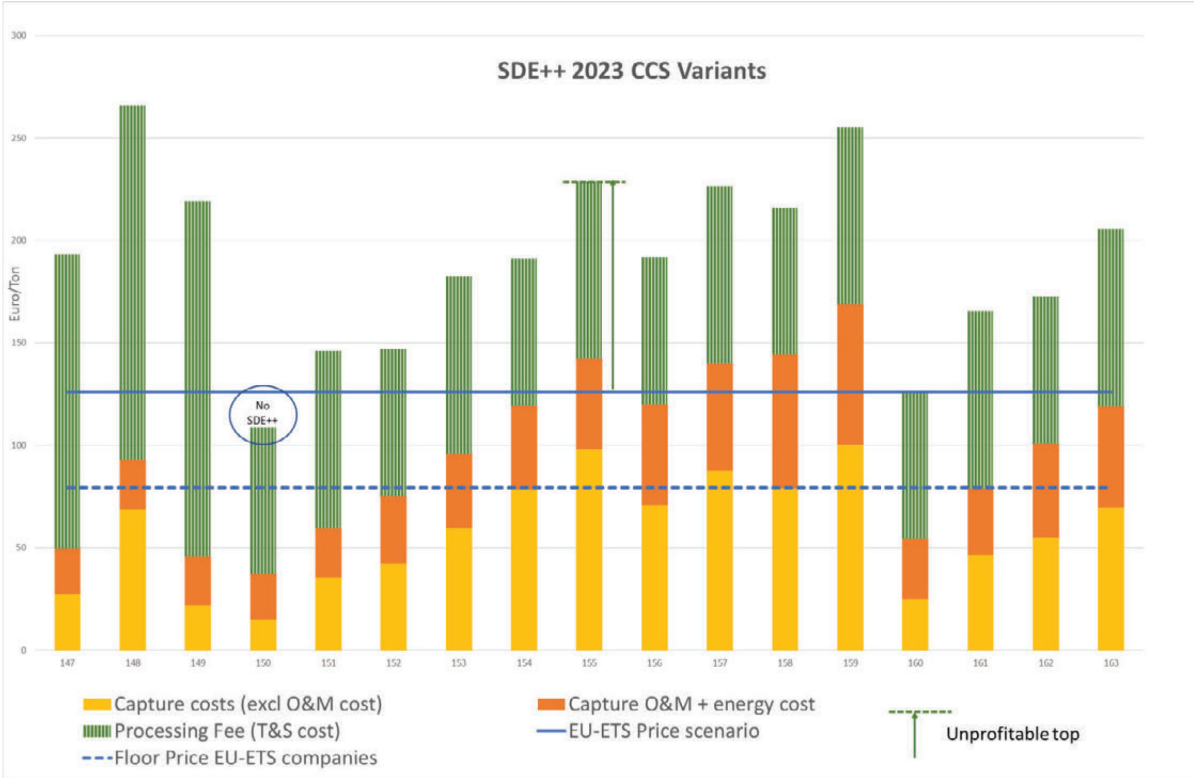
European: Innovation Fund (IF) and Connecting Europe Facility (CEF)



SDE++ in support of CCS

Main T&S cost variations:
- 4000 vs 8000 hours/year
- Liquid vs. Gaseous transport

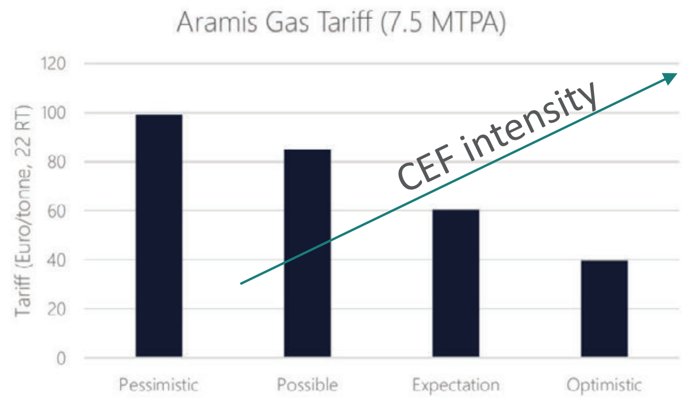
- The Netherlands has introduced a CO2 levy (increase over time) to ensure industry will decarbonize
- SDE++ is a Contract for Difference and helps to pay for the "unprofitable top" of decarbonization.
- 183 decarbonization techniques are ranked based on "Subsidy Intensity" allowing comparison of CCS with solar, wind, biomass, hydrogen and electrification projects.
- Lowest decarbonization costs (€/t abated) will receive the subsidy
- Unprofitable top for CCS is the sum of **Capture costs** and **T&S fee** minus **EU-ETS price**



Independent review of T&S tariff for SDE++
(Xodus contracted by Ministry in H1 2022)

- Securing (40% assumption) CEF grant funding is essential to lower the tariff
- Definition of reasonable reward for risks (reflected in IRR) under discussion
- The trunkline capacity is 22 Mtpa. The current Launch Phase of the Aramis project is 5 Mtpa to be secured by joint marketeer, with a view that a further 2.5 Mtpa can be secured prior to Final Investment Decision (FID)
- There is potentially considerable residual value in the trunkline post SDE++ subsidy after 15 years, if further stores and emitters can be identified

Scenario	Description
Pessimistic	High Cost & Zero CEF funding
Possible	High CAPEX & OPEX, transport CEF only
Expectation	Base Case, P50 Costs, CEF funding
Optimistic	Low Cost + CEF Transport & Stores



ARAMIS

Disclaimer

EBN, Gasunie, Shell and TotalEnergies entered into a cooperation agreement to explore the possibility of setting up a joint venture to jointly develop a CO_2 transport activity unlocking a large Dutch offshore storage area. The present documentation and related discussions are entirely prospective and non-binding. They create no obligations on EBN, Gasunie, Shell, TotalEnergies or the prospect.

Session 5: Scenarios for CCS

5.1. Impact of CCS costs on deployment of CCS in IAMs

Harmen Sytze de Boer (PBL)

Impact of CCS costs on deployment of CCS in IAMs

IEAGHG CCS Cost Network Workshop

Detlef van Vuuren (PBL & UU) Machteld van den Broek (RUG) and Harmen Sytze de Boer (PBL)

13 April 2021

Planbureau voor de Leefomgeving

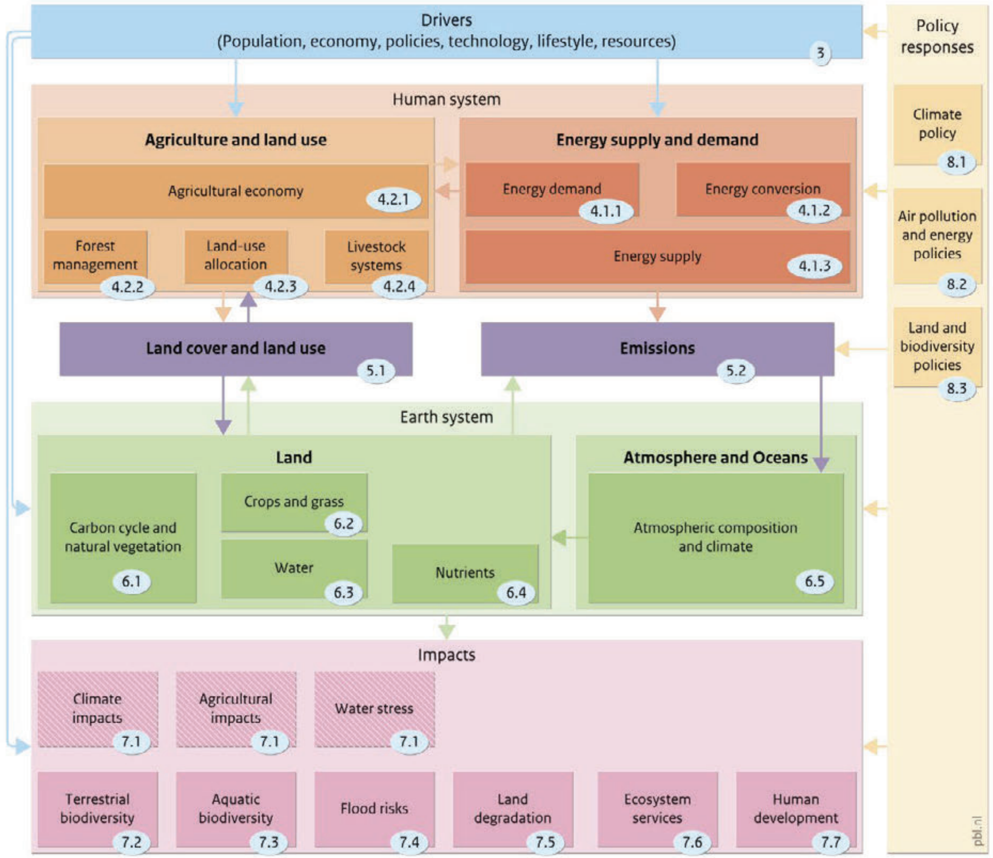
PBL

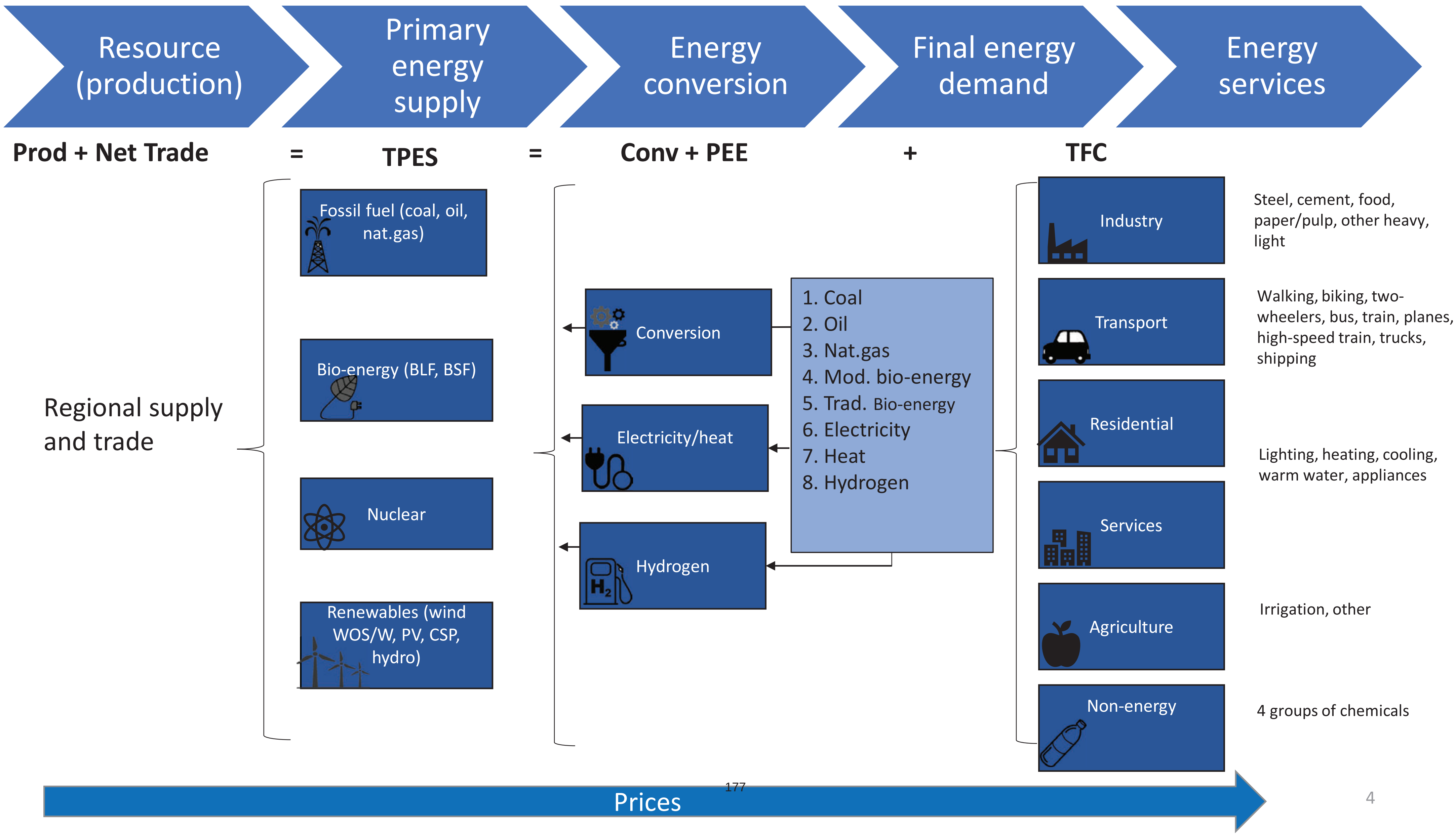
- Planbureau voor de Leefomgeving or PBL Netherlands Environmental Assessment Agency
- Independent scientific research institute:
  - Environment
  - Nature
  - Spacial planning
- Climate, air and energy department
- IMAGE team

Planbureau voor de Leefomgeving

IMAGE

- Integrated Model to Assess the Global Environment
- Global model, 26 world regions, yearly time steps towards 2100
- Able to simulate possible futures. Example outputs:
  - Greenhouse gas emissions
  - Energy use
  - Land use
- Simulation model which can help solving the climate change puzzle





Resource (production)
Primary energy supply
Energy conversion
Final energy demand
Energy services
Prod + Net Trade
=
TPES
=
Conv + PEE
+
TFC
Regional supply and trade
Fossil fuel (coal, oil, nat.gas)
Bio-energy (BLF, BSF)
Nuclear
Renewables (wind WOS/W, PV, CSP, hydro)
Conversion
Electricity/heat
Hydrogen
1. Coal
2. Oil
3. Nat.gas
4. Mod. bio-energy
5. Trad. Bio-energy
6. Electricity
7. Heat
8. Hydrogen
Industry
Transport
Residential
Services
Agriculture
Non-energy
Steel, cement, food, paper/pulp, other heavy, light
Walking, biking, two-wheelers, bus, train, planes, high-speed train, trucks, shipping
Lighting, heating, cooling, warm water, appliances
Irrigation, other
4 groups of chemicals
Prices
4

Planbureau voor de Leefomgeving

Carbon capture in IMAGE

- CO_2 can be captured in multiple sectors:
  - Power sector
  - Secondary heat
  - Hydrogen
  - Industry
    - Steel
    - Cement
    - Paper and pulp
    - Other industry
  - Liquid biomass production
  - Transformation
    - Cokes production
    - Other transformation (for example: refineries)
  - Direct air capture
- Carbon dioxide removal
  - (Reforestation)
  - Biomass with CCS
  - Direct air capture

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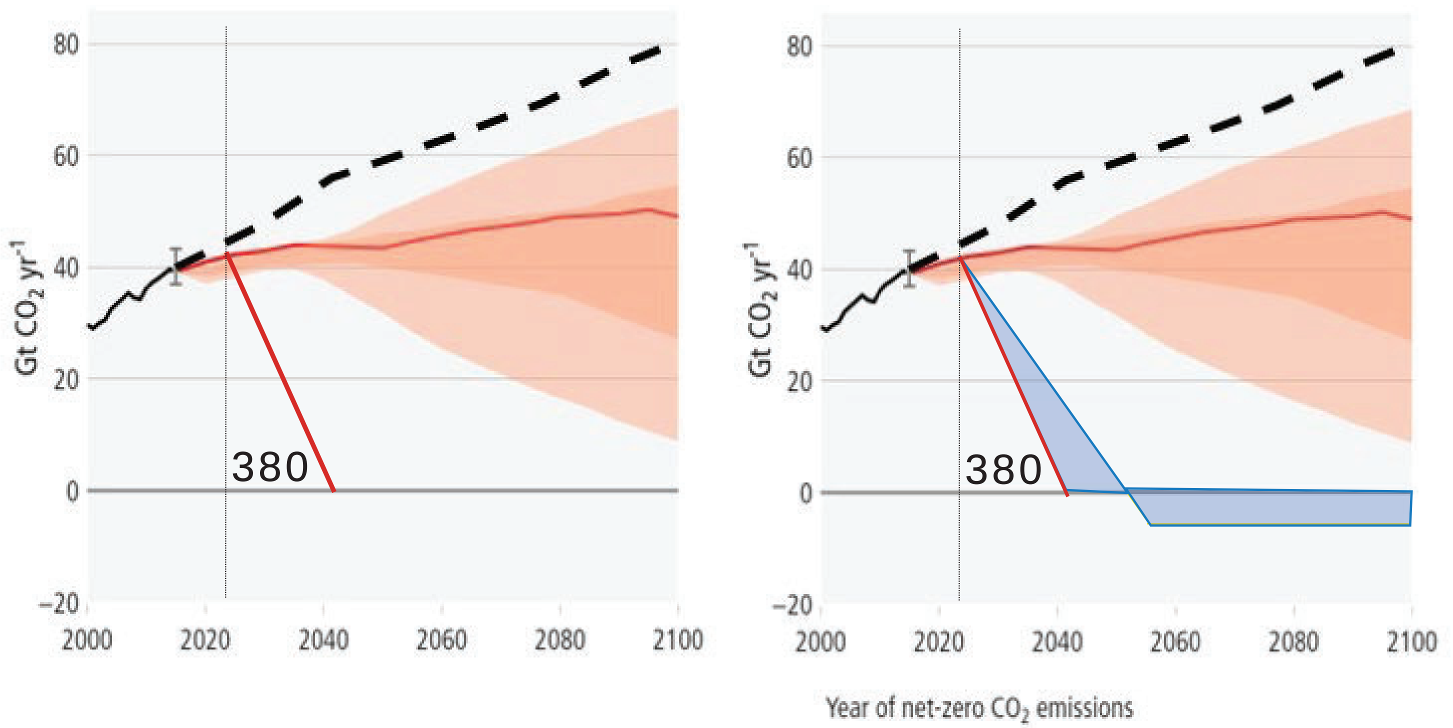
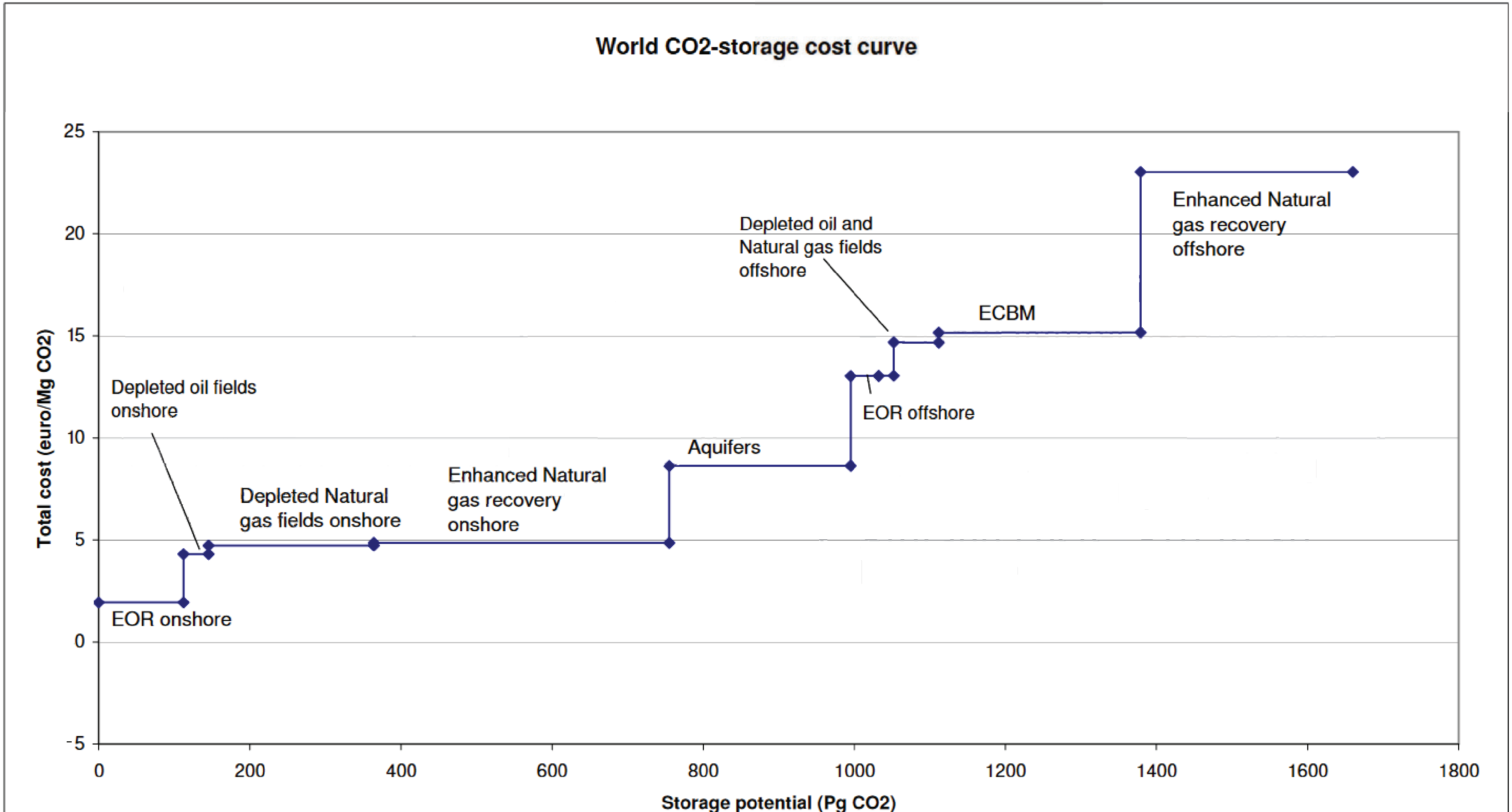
Carbon budget

- Linear relationship between cumulative CO_2 emissions and climate change (with some uncertainty)

- Means that each temperature goal (with some chance of reaching it) corresponds with maximum amount of CO_2 emitted




World CO2-storage cost curve
Total cost (euro/Mg CO2)
Storage potential (Pg CO2)
25
20
15
10
5
0
-5
0
200
400
600
800
1000
1200
1400
1600
1800
Depleted oil fields onshore
EOR onshore
Depleted Natural gas fields onshore
Enhanced Natural gas recovery onshore
Aquifers
Depleted oil and Natural gas fields offshore
EOR offshore
ECBM
Enhanced Natural gas recovery offshore

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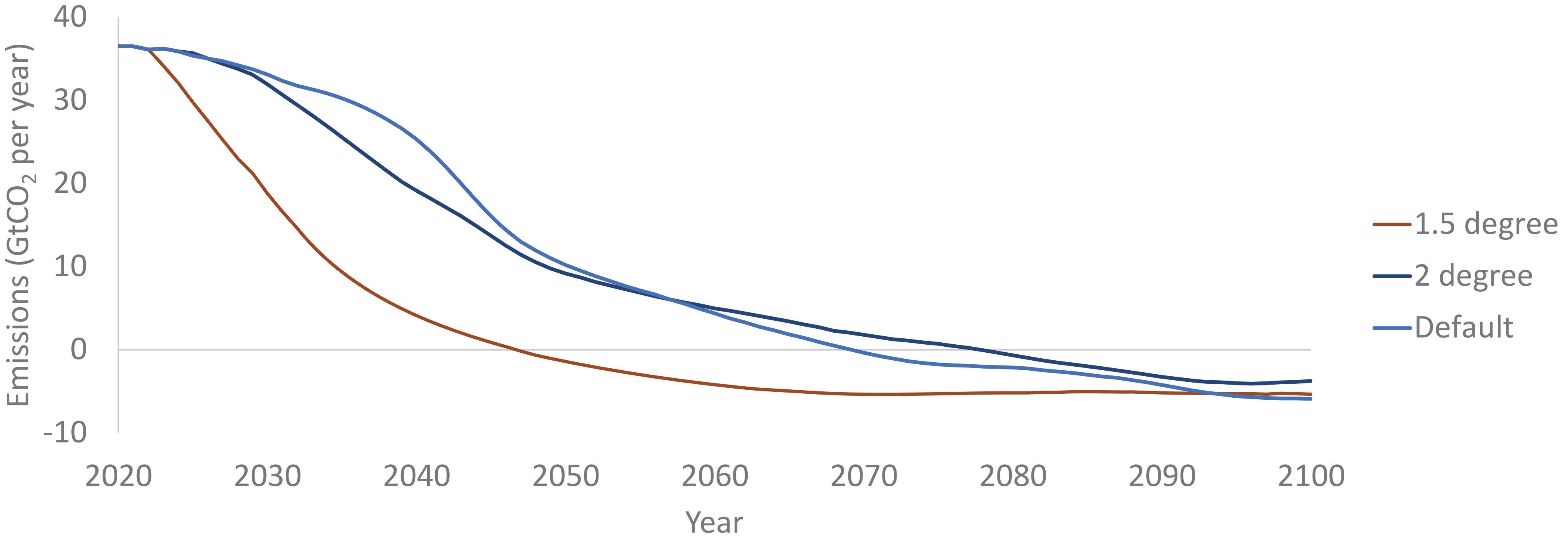
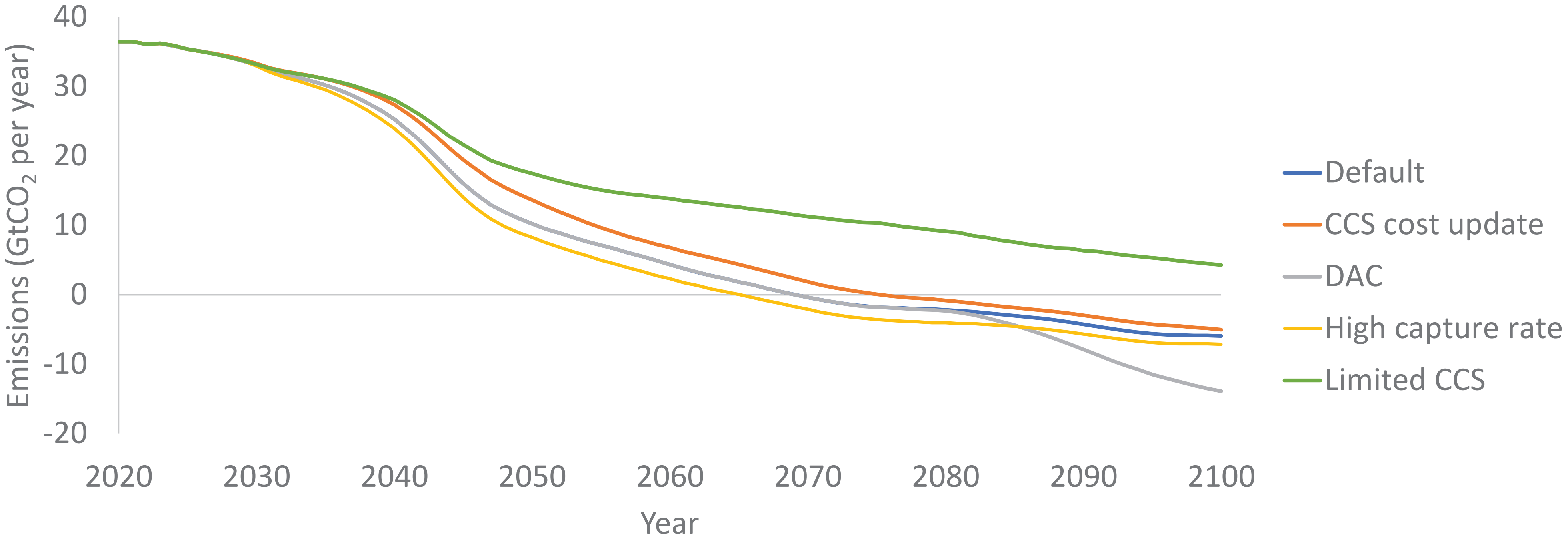
Sensitivity analysis

- Default
  - SSP2 middle of the road scenario
  - Diagnostic carbon price representing increasing ambition in climate mitigation
  - Price(t) = 80 USD * $1.05^{(t-2040)}$ (USD 80 reached in 2040, USD ~1350 in 2100)
- CCS cost update
  - Used ~60 USD/tCO_2 for transport and storage of CO_2
- DAC
  - Use of direct air capture allowed
- High capture rate
  - Assumed 100% capture rate throughout the model
  - Default: 80-90% depending on sector
- Limited CCS
  - Maximum CCS rate of 5 $GtCO_2$ in 2050, slightly decreasing towards 2100

Energy and industry emissions

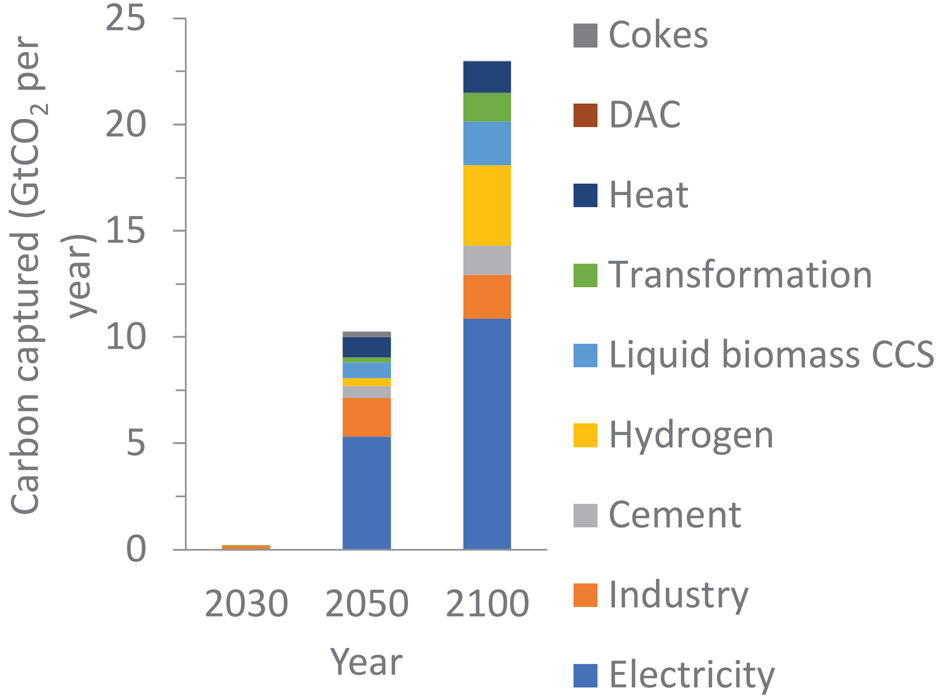


Energy and industry emissions

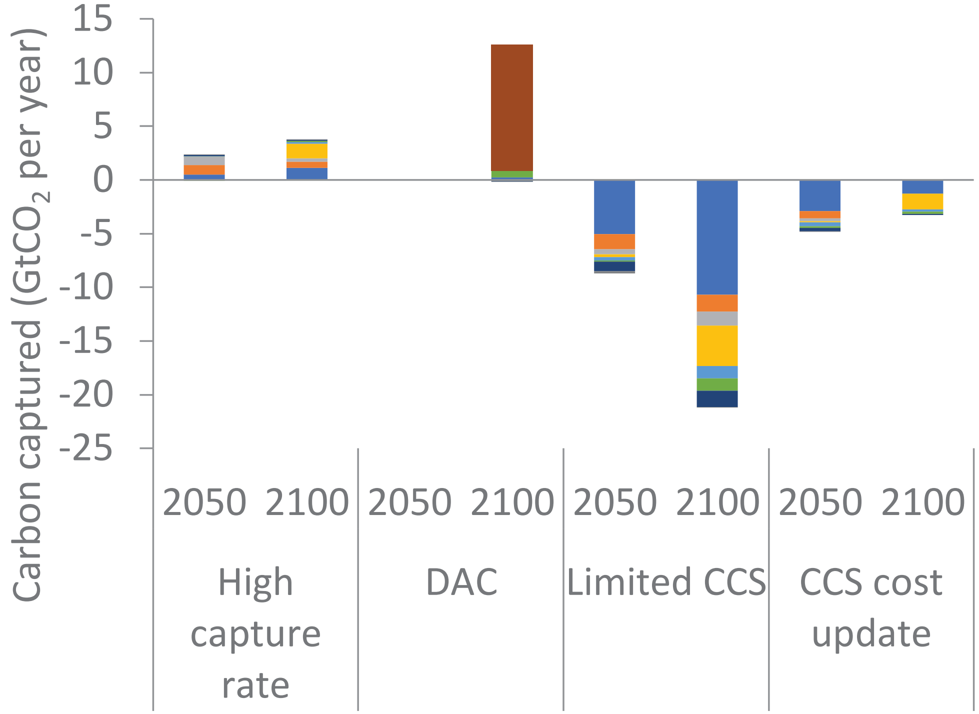


Planbureau voor de Leefomgeving

Carbon captured



Difference to default



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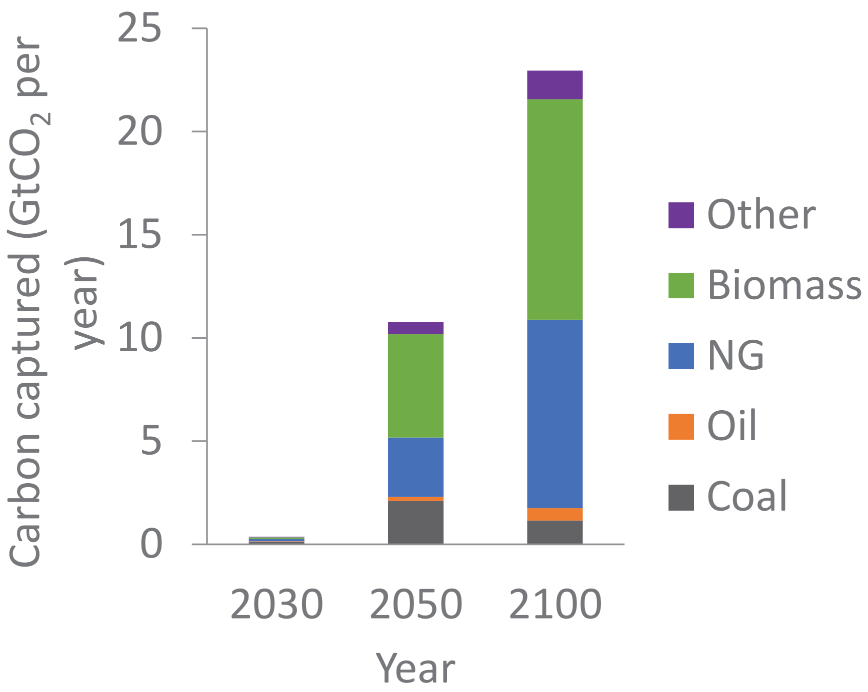
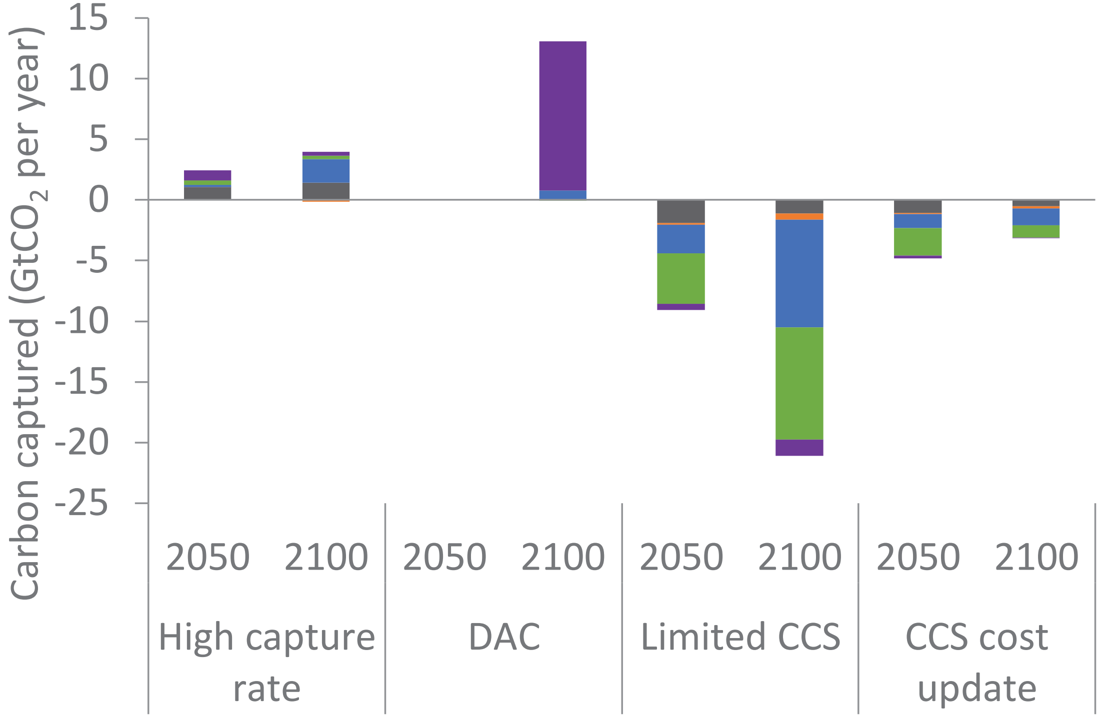
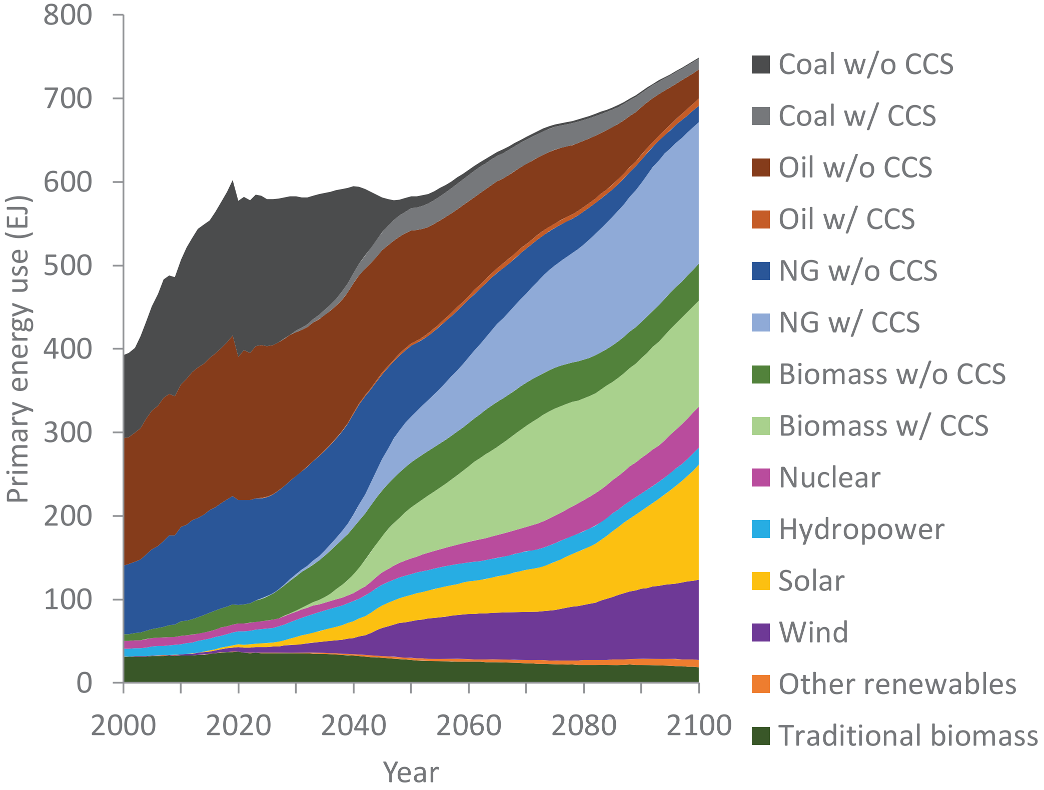
Carbon captured per source   Difference to default



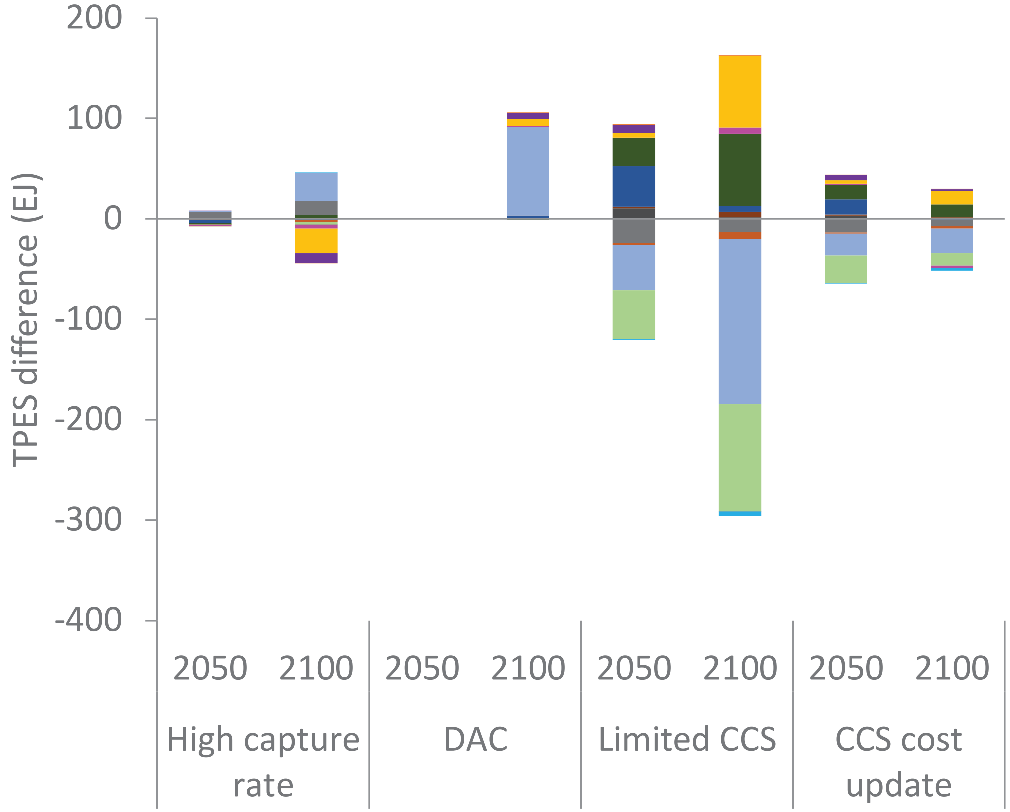


Planbureau voor de Leefomgeving

Primary energy mix

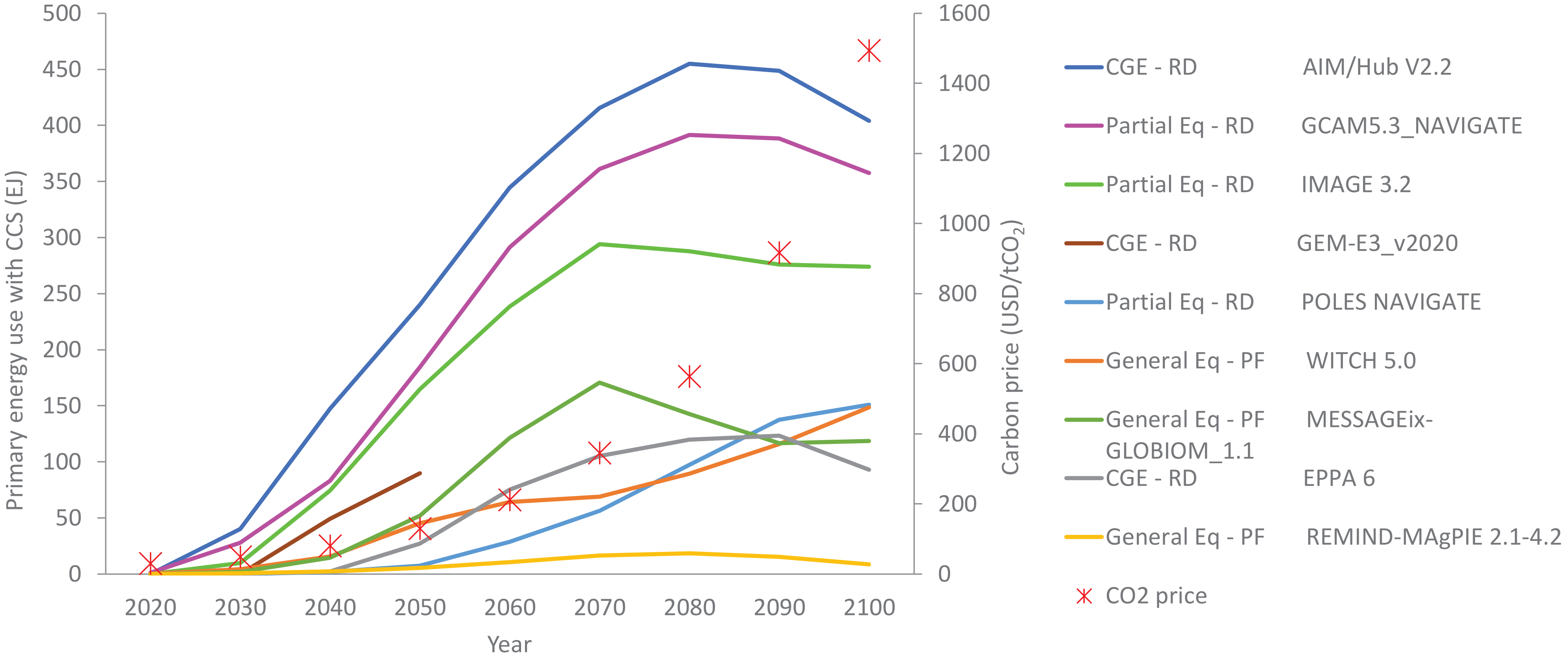


Difference to default



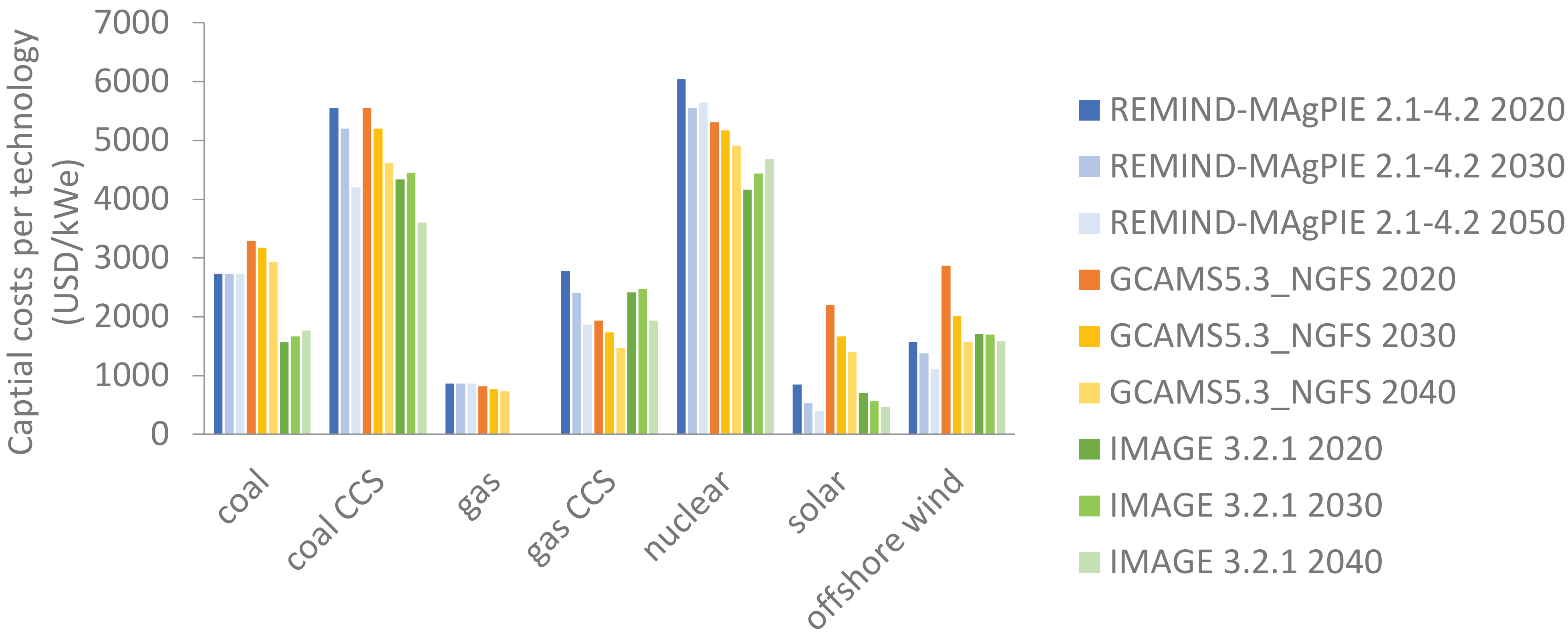
Planbureau voor de Leefomgeving

Comparison other models



Planbureau voor de Leefomgeving

Possible explanation? More research needed



Planbureau voor de Leefomgeving

To conclude

- Further research required to explain differences between models
- However, all models see an important role for CCS and CDR in climate mitigation
- CDR plays an important role need to compensate GHG emissions <2050 term with negative emissions >2050
- Uncertainties in CCS development can have a big impact on mitigation rate
- Transparency on costs and potential for CCS is very valuable

5.2. CCUS in IEA scenarios

Mathilde Fajardy (IEA)

CCUS in IEA scenarios

Dr. Mathilde Fajardy, IEA

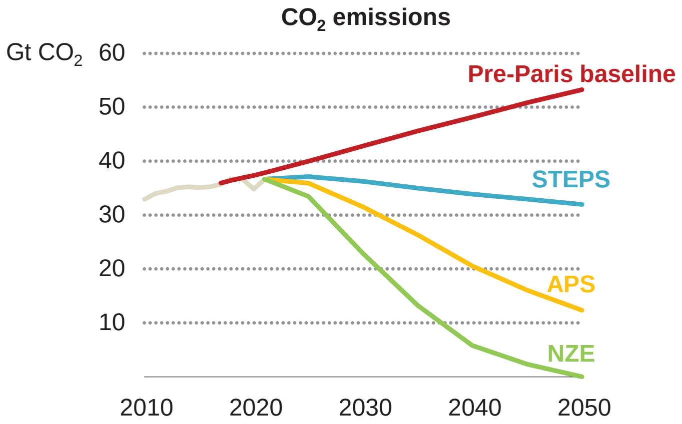
7th IEAGHG CCS Cost Network Workshop

12-13 April 2023

International Energy Agency

Main features of the Global Energy and Climate Model

- Large-scale simulation model
- Integrates WEM and ETP modelling frameworks
- Time frame: 1970 - 2050
- 26 demand regions:
    - 11 countries: Brazil, Canada, China, India , Indonesia , Japan , Korea, Mexico, South Africa, Russia, US
- Around 120 supply regions
- Includes IEA historical energy statistics and short-term energy market trends
- Inputs: technology cost, performance, historical technology developments, energy statistics and balance, policies and regulations, socioeconomic drivers
- More details here: IEA (2022), Global Energy and Climate Model documentation

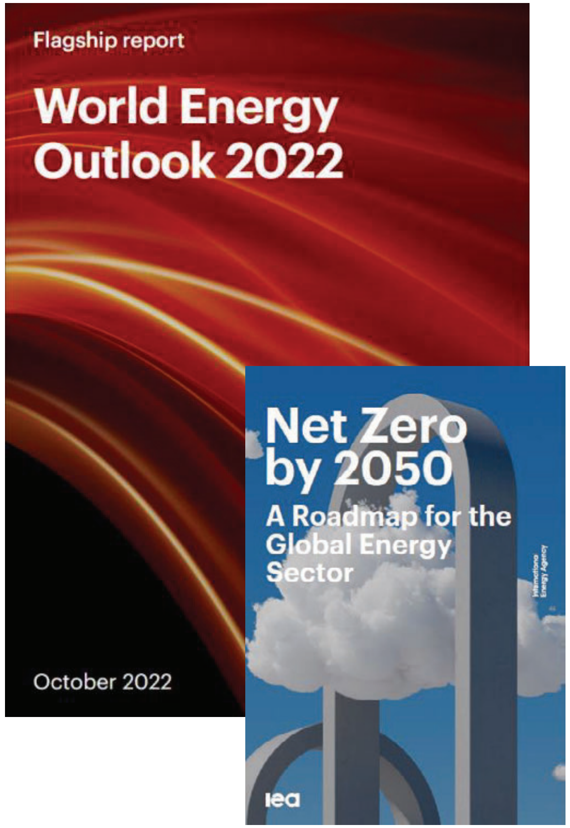


Scenario analysis in the World Energy Outlook

The *World Energy Outlook (WEO)* uses the latest available data to analyse energy, emissions and climate trends.

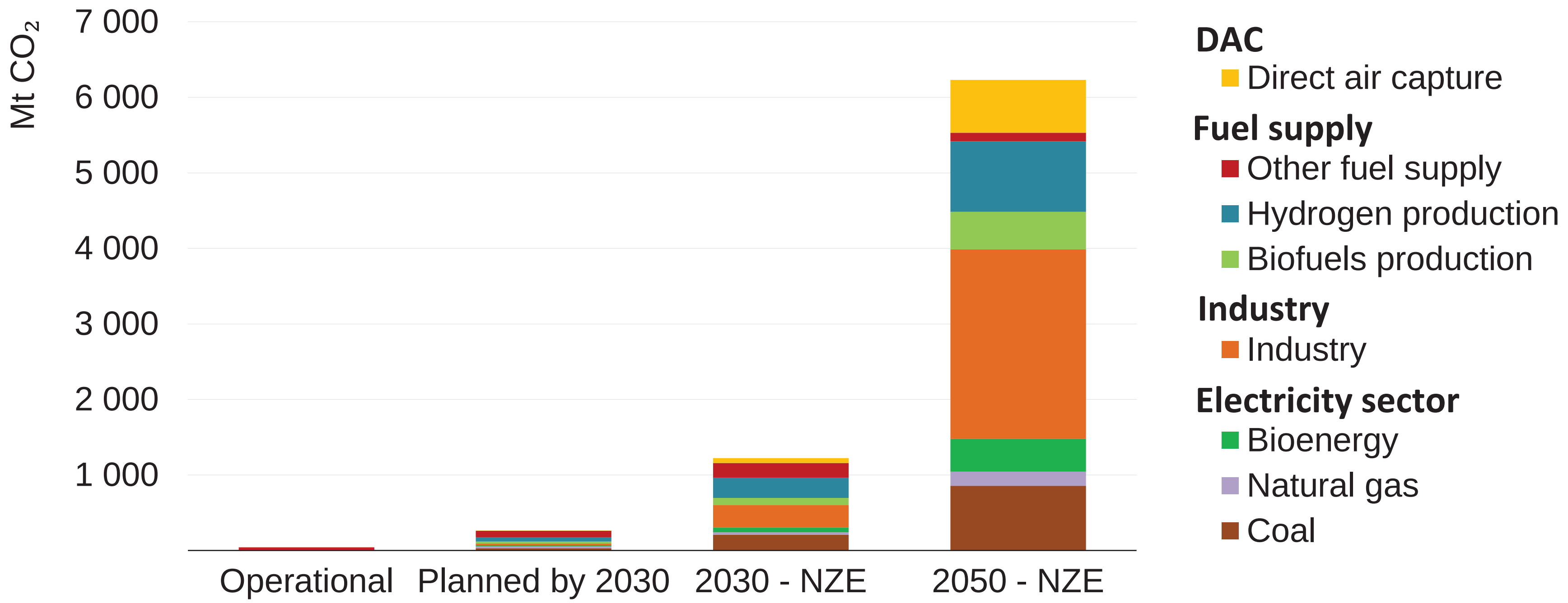
3 core scenarios

Where do existing policies take us?	*What is the impact of announced net zero and other pledges if they are met in full?*	*What is required for the energy sector to reach net zero CO_2 emissions by 2050?*
STEPS	**APS**	**NZE**
Stated Policies Scenario	Announced Pledges Scenario	Net Zero Emissions by 2050 Scenario



CCUS in clean energy transitions

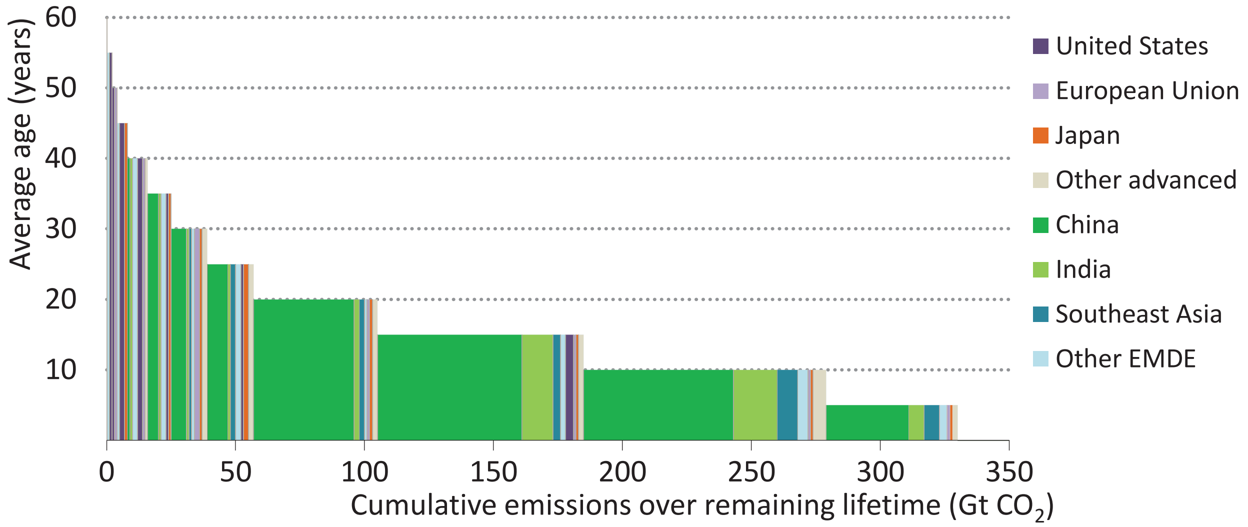
Global CO_2 capture by operating and planned source relative to the NZE Scenario, 2050



Around 1.2 Gt of CO_2 is captured per year by 2030, increasing to 6.2 Gt of CO_2 by 2050, with a predominant role for process emissions, power retrofits, hydrogen production and removals.

1. CCUS for existing infrastructure

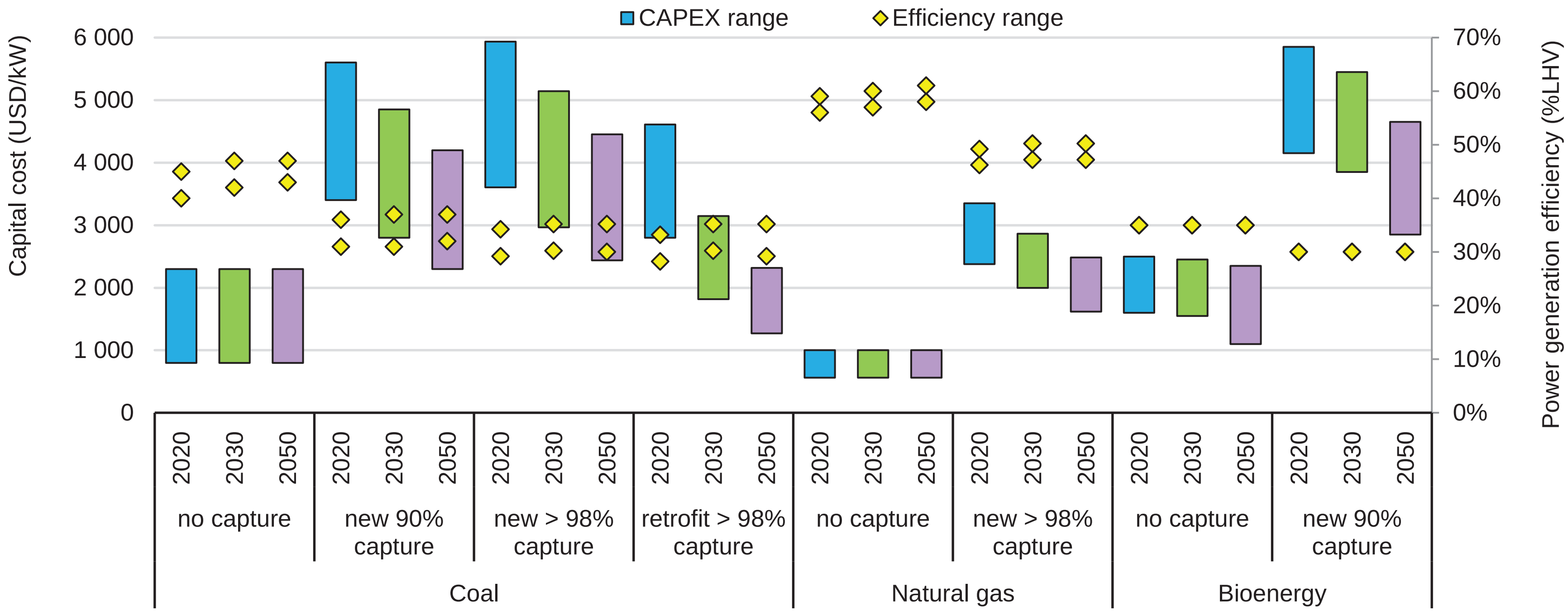
Cumulative emissions from existing coal power plants
at current use by age and region, 2022-2100



CCUS enables the continued operation of power (particularly coal) and industrial plants – many of which have only recently been built.

1. CCUS for existing infrastructure – techno-economics

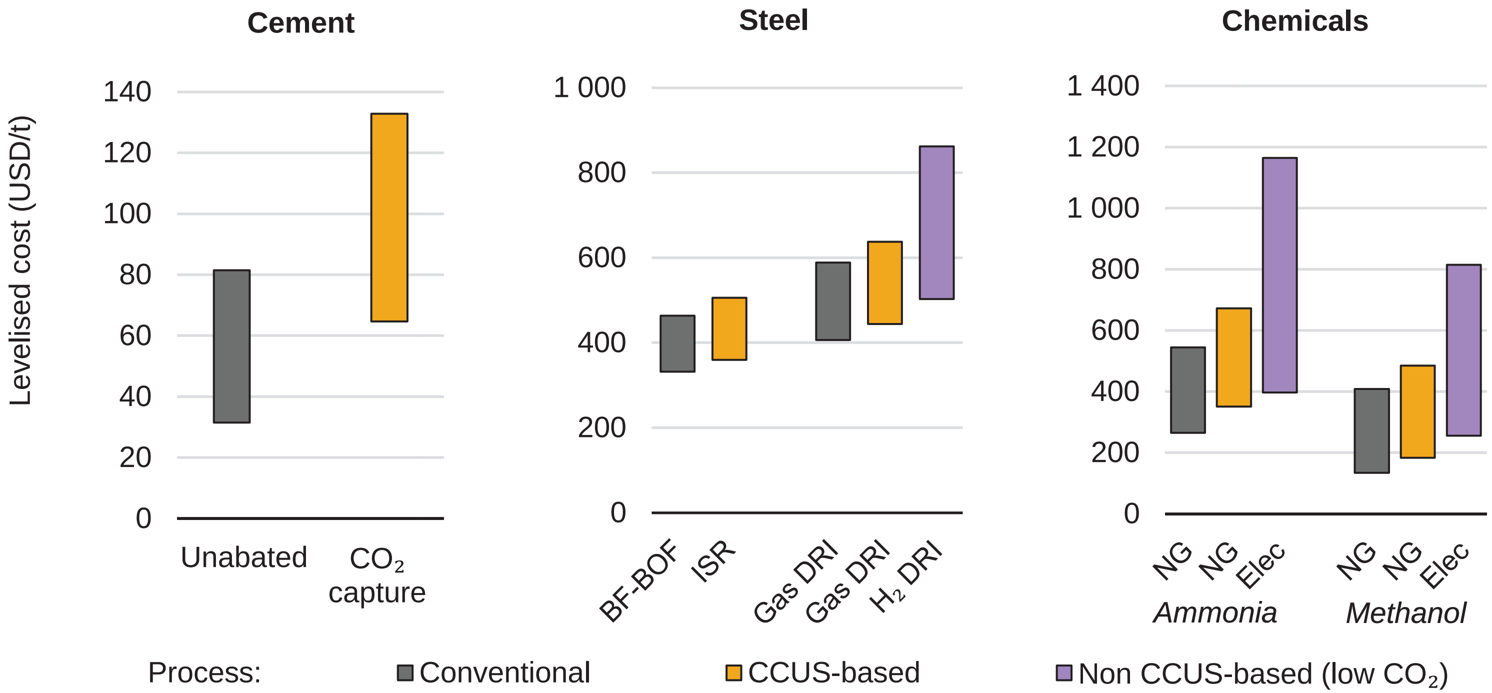
Techno-economic assumptions for CCUS in power



CCUS comes with sizable additional investment and efficiency penalty, but important cost reductions can be achieved with deployment. > 98% capture rates are achievable and only marginally impact costs and efficiency.

2. CCUS for hard-to-abate sectors

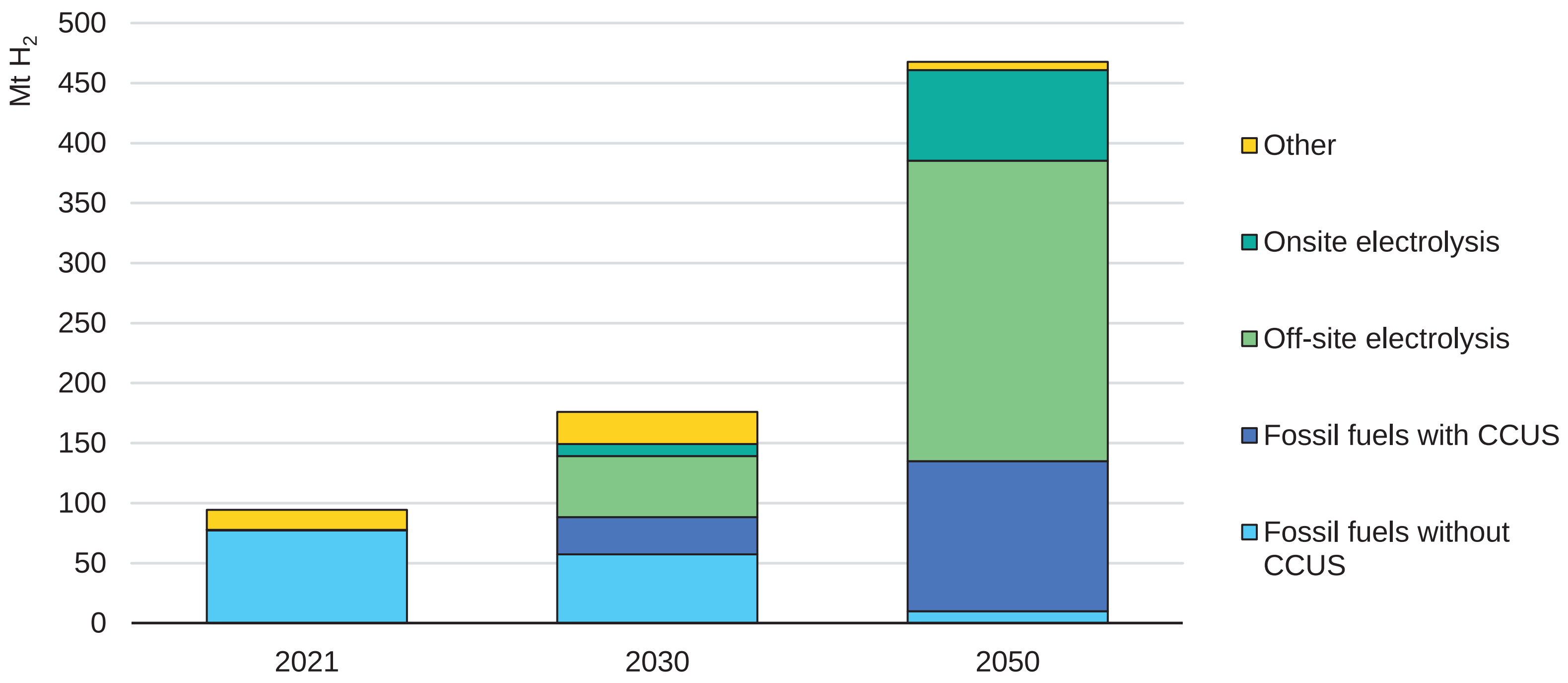
Levelised cost of materials and chemicals, 2021



CCUS provides is a cost-competitive option in steel (20% of final energy consumption is provided with CCUS) and chemicals, and one of the only options for cement.

3. CCUS for low-emission hydrogen production

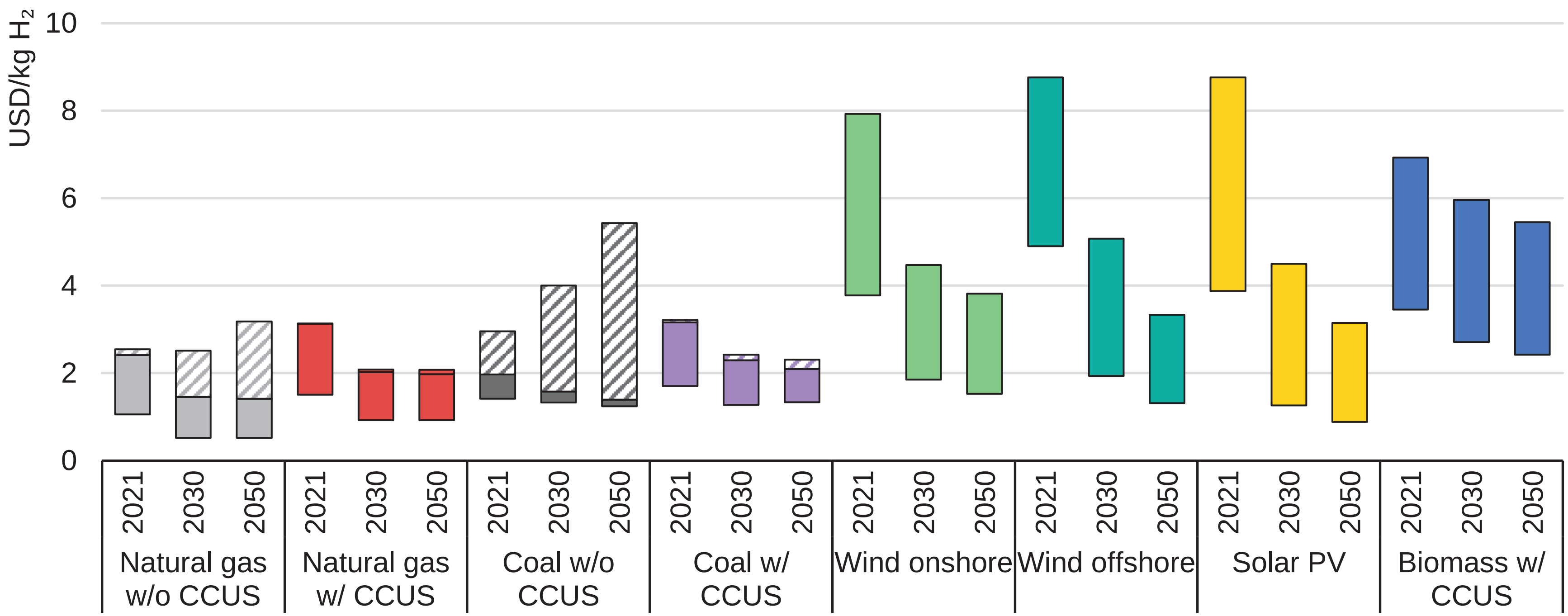
Hydrogen production in the NZE scenario, 2021-2050



CCUS makes up around 30% of hydrogen production in 2050.

3. CCUS for low-emission hydrogen production – techno-economics

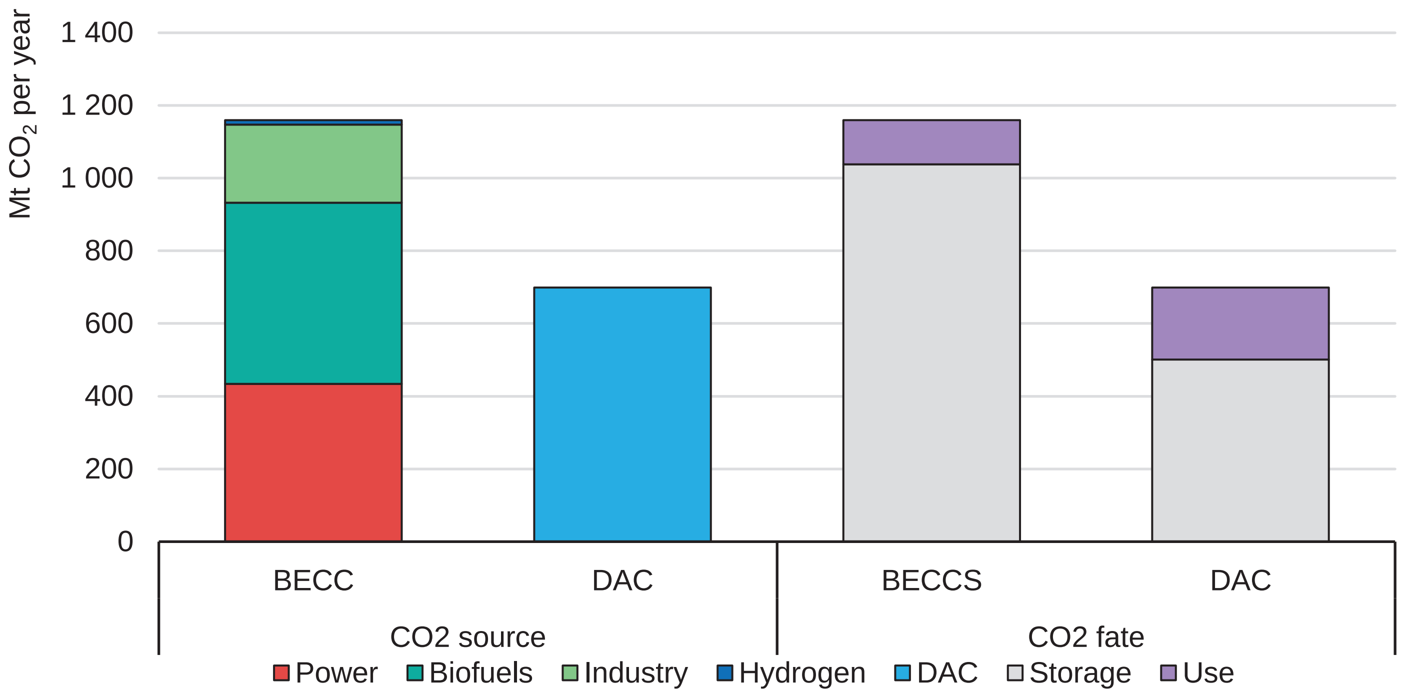
Levelised cost of hydrogen production, 2021-2050



CCUS-based hydrogen production is a low-cost option in regions with low availability of renewables electricity. High capture rates (95%) and low coal and gas upstream emissions are required.

4. CCUS for CO_2 removal

Source and fate of CO_2 captured from biogenic applications and from the air in the NZE, 2050

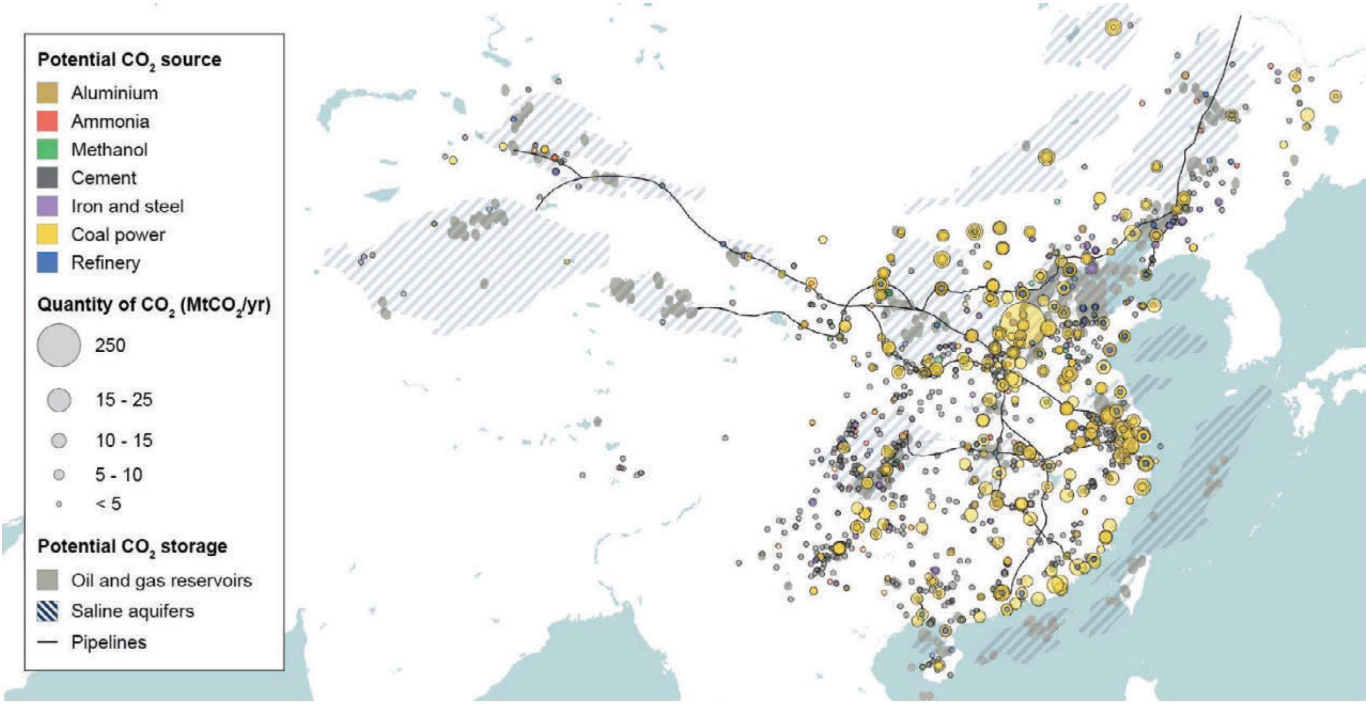


By 2050, 1.8 Gt CO_2 is capture from biogenic sources and from the air by 2050. Around 85% is permanently stored to provide removal, and the remainder is used as carbon-neutral feedstock for low-emission synthetic fuels.

CO_2 infrastructure considerations

- Model T&S assumptions:

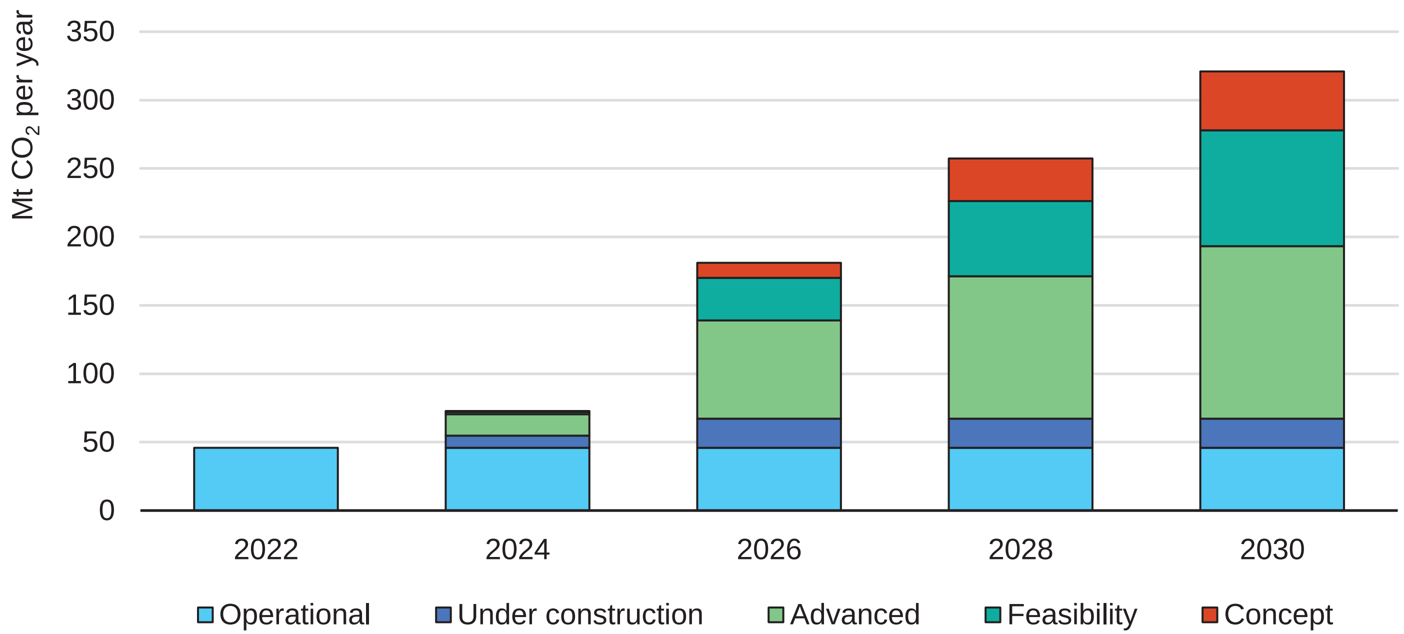
Region	USD/tCO_2
Europe	30-60
US	15
China	15
Rest of the world	20-25



Regional CO_2 T&S costs vary depending on distance to sinks, share of onshore/offshore, when available.
In China, 45% of existing power and industrial facilities are within 50 km of potential storage, and 64% within 100 km.

Deployment needs to further accelerate to meet NZE goals

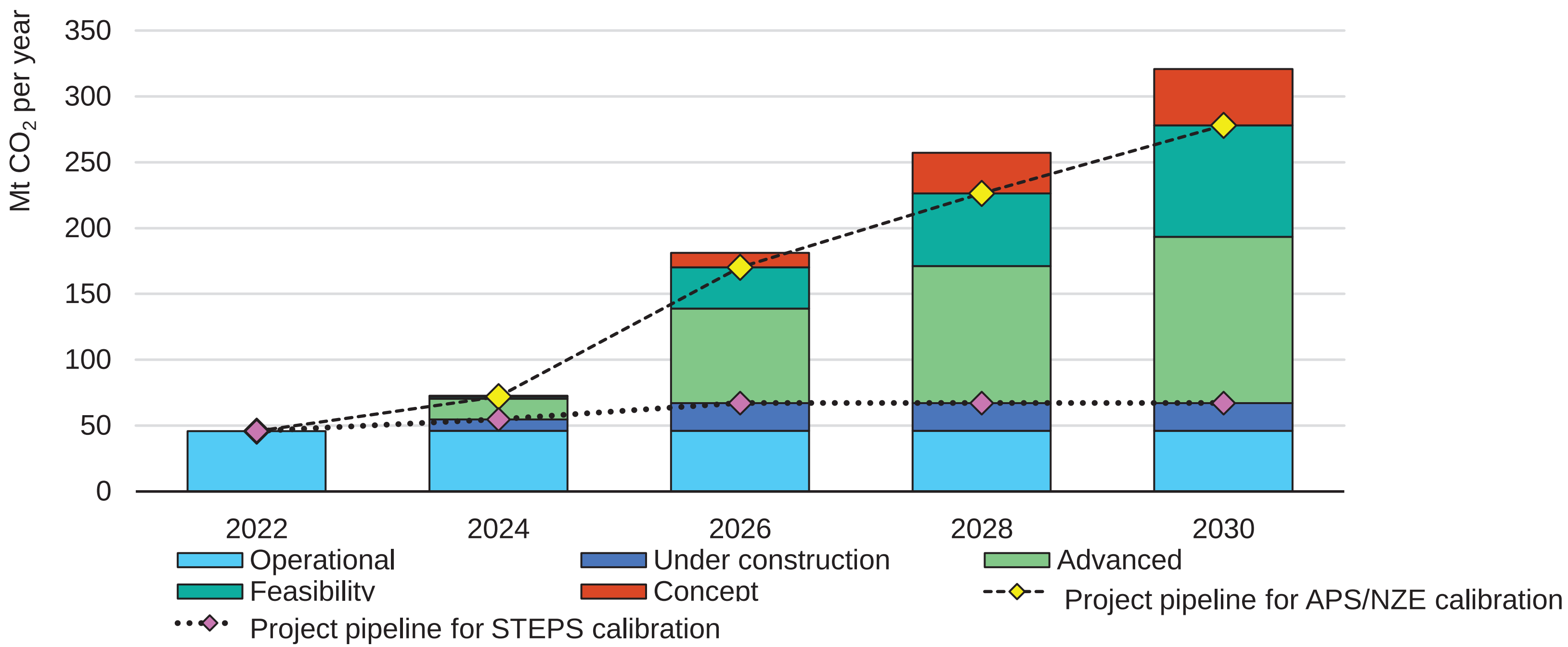
Operational and planned CO_2 capture capacity compared to NZE, 2022-2030



In 2022, more than 140 new projects were announced, increasing planned capture capacity by 30%. Currently planned capacity for 2030 represents just above a quarter of the CCUS required in the NZE Scenario.

Deployment needs to further accelerate to meet NZE goals

Operational and planned CO_2 capture capacity compared to NZE, 2022-2030



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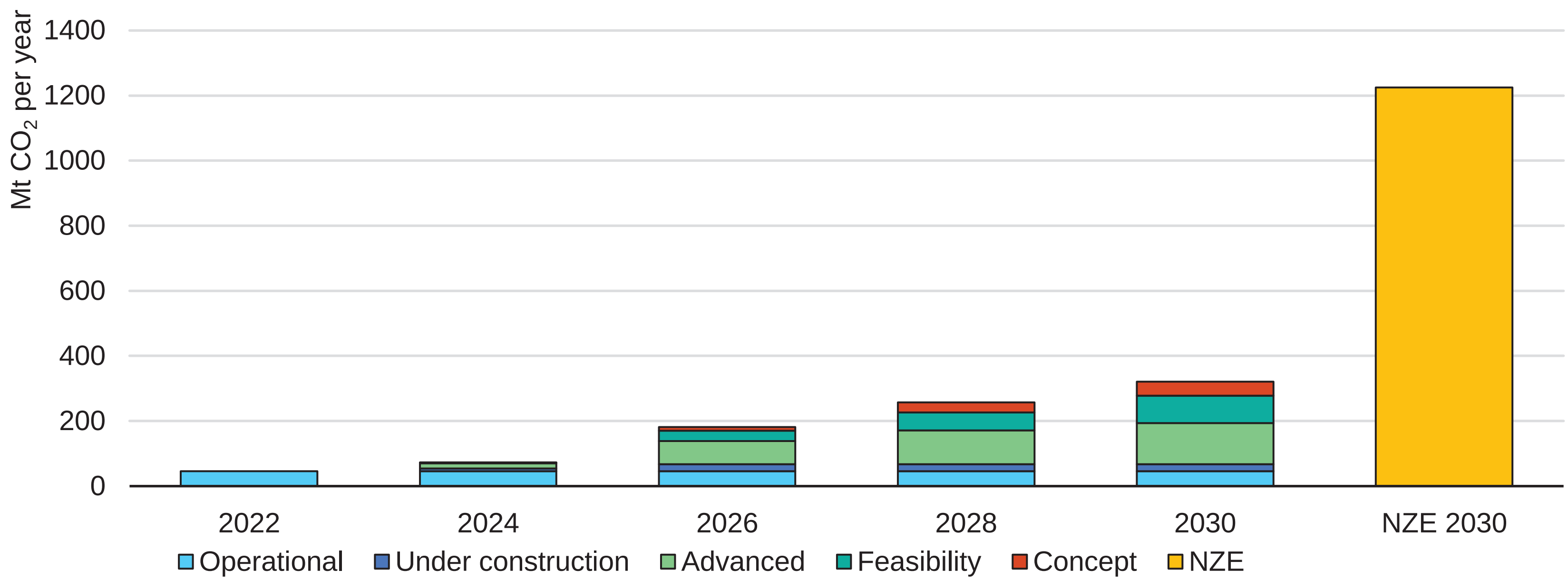
Deployment needs to further accelerate to meet NZE goals

Operational and planned CO_2 capture capacity compared to NZE, 2022-2030



In 2022, more than 140 new projects were announced, increasing planned capture capacity by 30%. Currently planned capacity for 2030 represents just above a quarter of the CCUS required in the NZE Scenario.

Government and industry action this decade is crucial

Four high-level priorities for governments and industry would accelerate the progress of CCUS:

1 Create the conditions for investment

2 Target the development of industrial clusters through shared CO_2 infrastructure

3 Identify and develop CO_2 storage

4 Boost innovation for key technologies

Breakout Session 1: High capture efficiencies

B1.1. Zero emissions fossil fired power plants using conventional post- combustion CO_2 capture.

Tianyu Gao (EPRI), et al.

High Capture Efficiencies

7th IEAGHG CCS Cost Network Workshop

Groningen, The Netherlands

April 12-13, 2023

Background

- Virtually all performance and cost information has been for 90% capture.
- Integrated Assessment Models use this cost information in scenario modeling, and they also show an increasing dependance on carbon removal technologies to achieve net zero.
- Is higher capture efficiency a cheaper alternative to 90% efficiency followed by carbon removal to achieve net zero?
- Can carbon capture on point source achieve negative emissions?

Zero-Emissions Fossil-Fired Power Plants Using Conventional Post-Combustion CO_2 Capture

7th IEAGHG CCS Cost Network Workshop

Tianyu Gao and Abhoyjit Bhown, EPRI

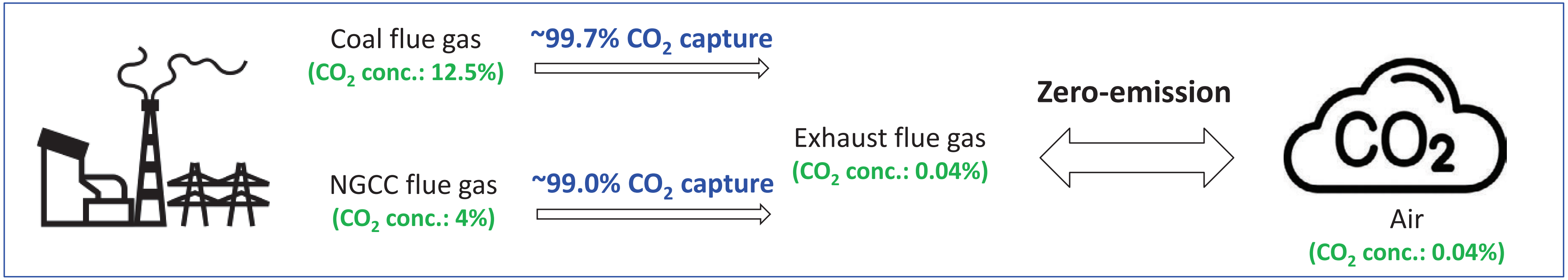
Yang Du (formerly at EPRI)
Gary Rochelle (UT Austin)

CO_2 Capture Efficiency – 90% or 99+%?

- CO_2 capture processes generally have been evaluated to capture ~90% of the CO_2 from power plant flue gas
  - This ~90% capture efficiency has been a long-standing benchmark, often considered to be where unit CO_2 capture cost ($/t CO_2 captured) started to increase more rapidly
- Current global climate models limit CO_2 capture to 90%, and assume the remaining ~10% (*~1 Gt/y for the current global power generation mix*) needs to be offset by negative-emissions technologies, such as direct air capture
  - For lowest cost for economy-wide net-zero emissions, the optimum CO_2 capture efficiency for flue gas can be higher than 90%

Zero-Emission Power Plants

"Zero Emission" means amount of CO_2 in = amount of CO_2 out in exhaust flue gas



In simulations, the zero-emissions scenario is defined as the condition when the CO_2/N_2 ratio in the exhaust flue gas is the same as that in current atmosphere, which is 0.0005276 (412 ppmv CO_2 and 78.084% N_2).

Details in *International Journal of Greenhouse Gas Control*, *111*, 103473

Existing Pilot Tests For High CO_2 Capture efficiency

Pilot plant	Flue gas type	Max. CO_2 capture efficiency achieved	CO_2 capture technology	Time
NCCC (US) (1 MWe)	Coal	99.9%	MEA	2018
	Coal	99.1%	PZ	2019
	NGCC	95.8%	PZ	2020
TCM (Norway) (10 MWe)	NGCC	~99%	MEA	2021
		~98%	PZ/AMP	2021

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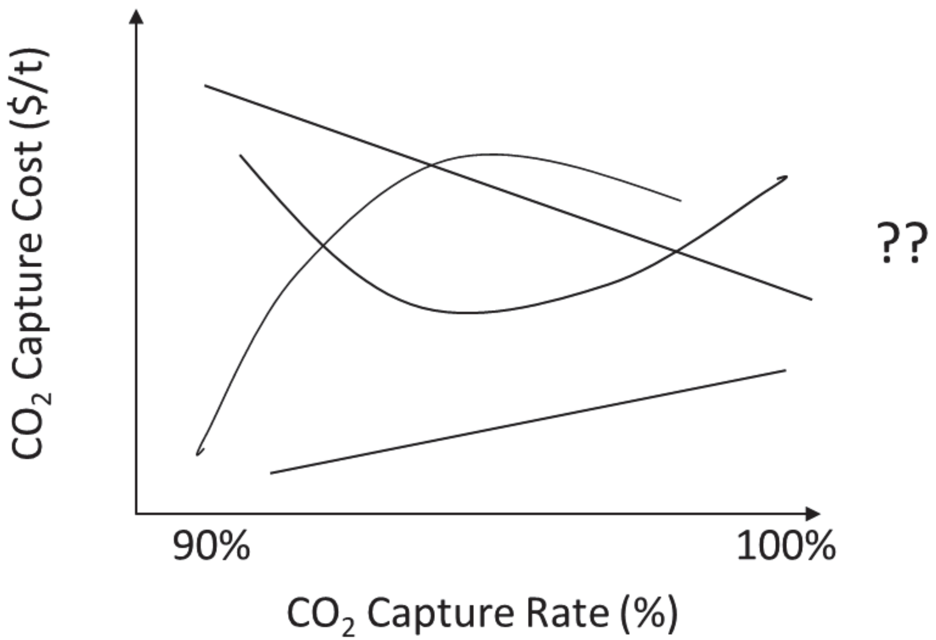
Objective of This Study

- Obtain a cost curve from 90% to nearly 100% CO_2 capture



- Potentially refine role of CCS in global climate models and role of fossil fuels in future energy mix

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Methodology

Solvent and model: MEA model:

- 30 wt% MEA, Developed by Carbon Capture Simulation for Industry Impact (CCSI[2]) in Aspen Plus

Process optimization parameters:

- Solvent flow rate
- Absorber height
- Lean loading
- Temperature of solvent
- Solvent intercooling configurations

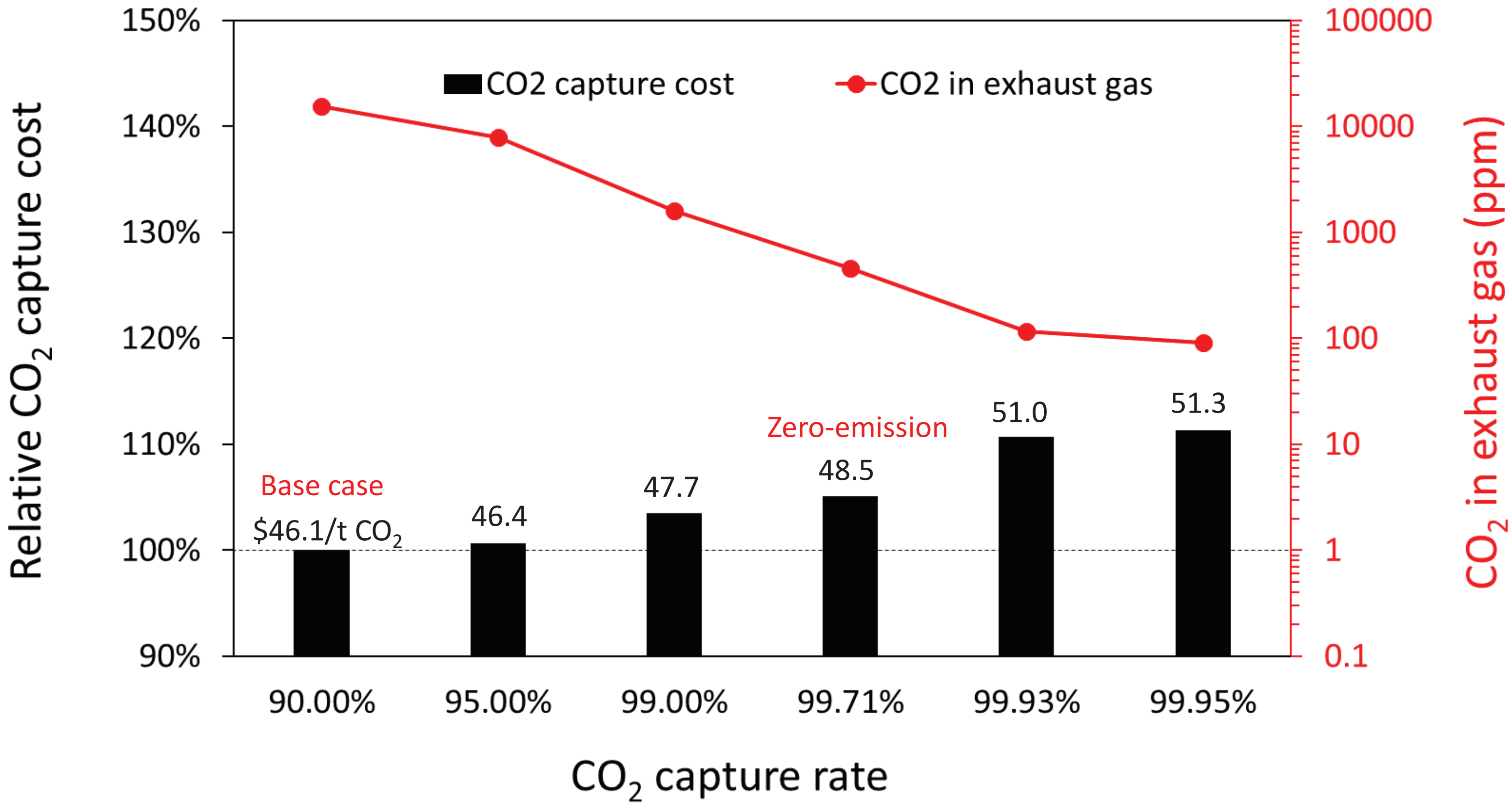
Reference cases:

- 650 MW (net) supercritical coal-fired power plant — Case B12A in DOE/NETL 2019 baseline report
- 646 MW (net) NGCC power plant — Case B31A in DOE/NETL 2019 baseline report

Cost methodology:

- DOE/NETL 2019 guideline (Revision 4)

CO_2 Capture Cost vs Capture Efficiency – Coal-fired plants



Process configuration: Absorber with conventional solvent intercooler; Simple stripper

For coal plants to achieve zero-emission, the **average** cost is ~5% higher than 90% capture

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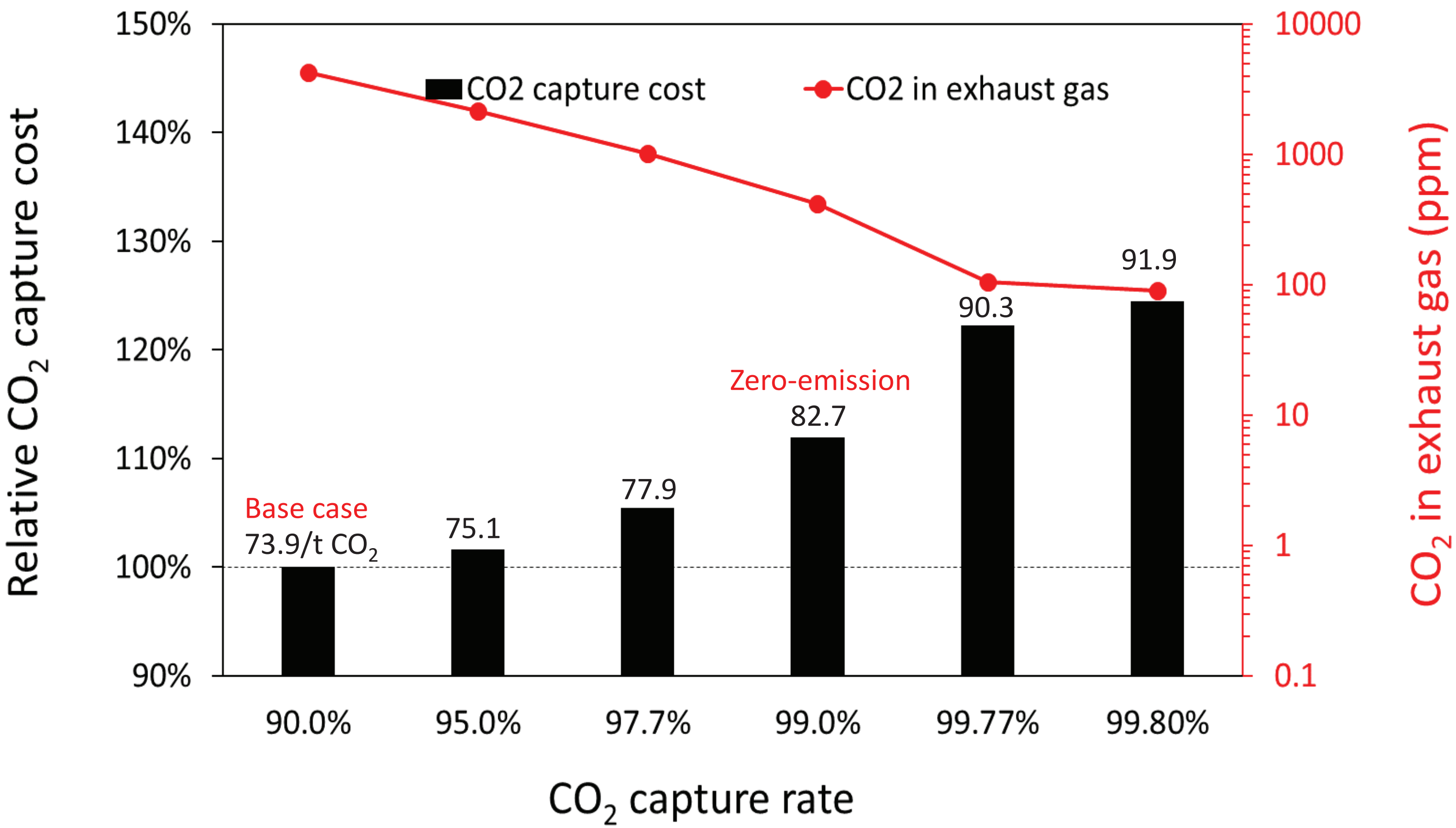
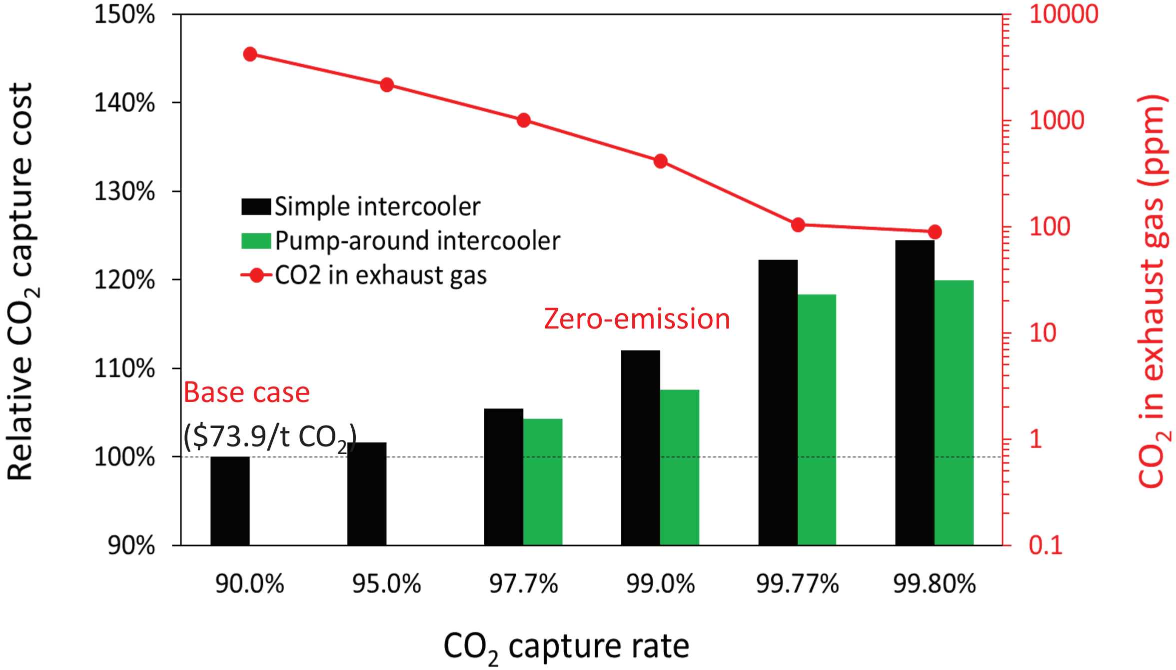
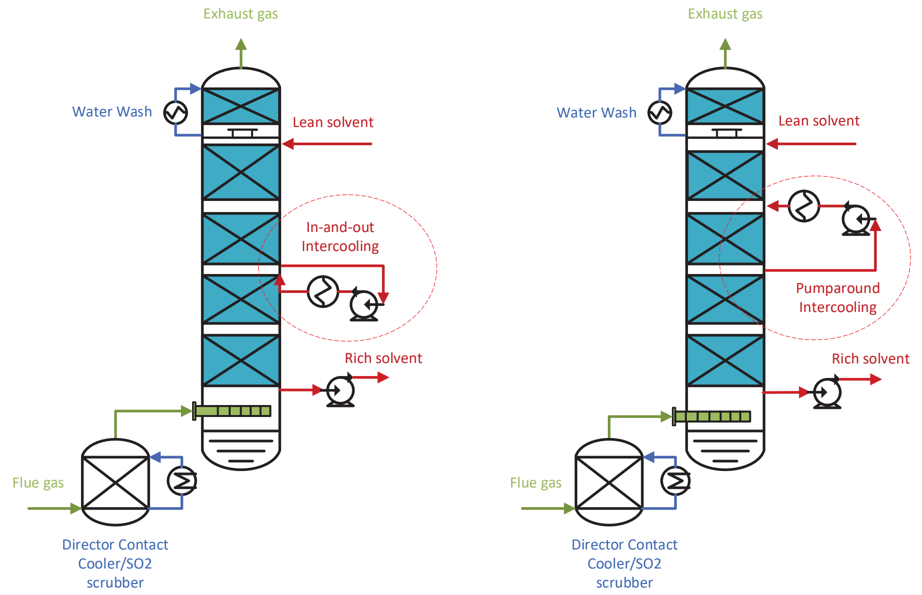
CO_2 Capture Cost vs Capture Efficiency – NGCC



- For NGCC to achieve zero-emissions, the **average** cost is ~12% higher than 90% capture
- The larger cost penalty due to the low L/G, simple intercooling not as efficient for temperature control

CO_2 Capture Cost vs Capture efficiency – NGCC





With simple in-and-out intercooling, the cooling capacity is limited by the flowrate of the solvent. In the pump-around intercooling configuration, as the solvent is pumped from the lower section to the upper section, the flowrate can be enhanced locally

With pump-around intercooling, the **average** cost for NGCC to achieve zero-emissions is 7.6% higher than that at 90% capture

Marginal CO_2 Capture Cost

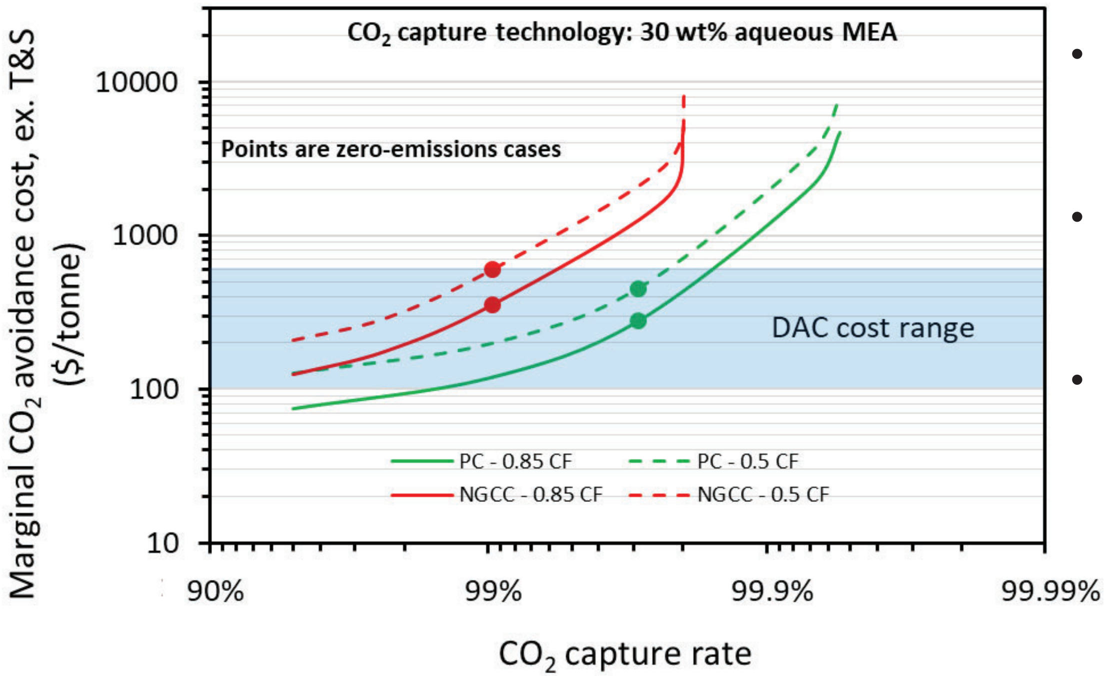
- Although increasing the level of CO_2 capture from 90% to that at zero-emissions has a small effect on the <u>**average**</u> cost, the **marginal cost may increase rapidly past a certain level of CO_2 capture**.
- It is important to determine this **limiting level of CO_2 capture** for CCS at which **the marginal cost becomes higher than** the cost of using **DAC** to remove CO_2 from the atmosphere. (i.e., how much do we need to rely on DAC to achieve zero-emissions for power plants?)

$$Marginal\ cost|_{x2} = \frac{\partial C}{\partial x}_{x2} \approx \frac{C_{x2} * x_2 - C_{x1} * x_1}{x_2 - x_1}$$

x = CO_2 capture (%); x_2 is a higher level of CO_2 capture than x_1

C = CO_2 capture cost

Marginal CO_2 Capture Cost vs DAC Cost



- As a novel technology which has not been demonstrated at scale, the cost estimate for DAC has a high degree of uncertainty
- At high capacity factor (CF), the marginal cost of CCS at zero emission is comparable to the average claimed cost for DAC
- When CF is low, it may be beneficial to couple CCS with DAC to fully decarbonize PC and NGCC plants

	95% capture		Zero-emission (400 ppm CO_2 in exhaust gas)		Negative-emission (100 ppm CO_2 in exhaust gas)	
Type	PC	NGCC	PC	NGCC	PC	NGCC
Marginal cost at this capture efficiency ($/t CO_2)*	$75	$124	$278	$354	>$1000	

Based on CF of 0.85. At CF of 0.5, the costs are 60-70% higher

Summary

- It is technically feasible for both coal-fired and NGCC power plants to achieve zero emissions using CCS (~400 ppm CO_2 in exhaust gas).
- Solvent intercooling is important at high CO_2 capture efficiency, especially for NGCC
- At high plant capacity factor (CF), PC and NGCC plants can achieve zero-emissions with CCS alone at competitive costs
- When CF is low, it may be beneficial to couple CCS with DAC to fully decarbonize PC and NGCC plants (as long as DAC developers can demonstrate the cost they claim)

  EPRI

Discussion High Capture vs Biomass Cofiring

Cases			Zero Emission			Negative Emission
	90%	95%	99.7%	5% bio + 95%	10% bio + 90%	10% bio + 95%
LCOE, $/MWh	117.8	120.6	126.1	125.3	126.9	130.1
Cost of avoided, $/t	64.0	64.0	66.6	64.2	65.0	64.6
Incremental cost, $/t		64.0	119.4	67.3	83.4	74.3

Jiang, Kaiqi, et al. *Environmental science & technology* 54.4 (2020): 2429-2438.

While individual plants can achieve zero emissions by biomass, the aggregate amount of biomass may be limited to achieve net zero.

Discussion Topics

- Performance and cost improvements using other solvents? (EPRI has conducted similar work with piperazine that shows additional cost reductions relative to MEA).
- For power generation, we minimized \$/t capture using cost correlations. Are there better approaches?
- Are similar results for industrial capture observed?
- What type of data on high capture efficiency would be useful for integrated assessment models in order to compare to CDR costs (BECCS, DAC, …)?
- Should tax incentives like 45Q be applied to negative emissions CCS too?
- What should be the new “standard” for capture, if any? U.S. Dept of Energy is now using 95%.

B1.2. On the cost of (truly) zero carbon hydrogen with CCS.

Mathieu Lucquiaud (Univ. of Sheffield)

The University Of Sheffield. Energy Institute

Translational Energy Research Centre.

IEAGHG Cost Network, Groningen, Netherlands
12-13 April 2023

ON THE COST OF (TRULY) ZERO CARBON HYDROGEN WITH CCS

Prof Mathieu Lucquiaud
Chair of Clean Energy with Carbon Capture and Storage
Mechanical Engineering Department, University of Sheffield
Translational Energy Research Centre (https://terc.ac.uk/)

Acknowledgments:
Daniel Mullen, University of Edinburgh & SSE
Ryan Cownden, University of Sheffield
Prof Jon Gibbins, UKCCSRC & University of Sheffield

Overview

- 100% post-combustion capture
- 100% capture from SMR
- Levelised Cost of Hydrogen
- CO_2 intensity of hydrogen
- Zero life cycle CO_2 intensity of hdyrogen

100% post-combustion capture

- At ultra high capture levels, MUST account for atmospheric CO_2 in excess air used for combustion
  - Absorber capture rate ≠ effective capture rate
  - Absorber capture rate: Fuel CO_2 + Feedstock CO_2 + excess air CO_2
  - Effective capture rate: Fuel CO_2 + Feedstock CO_2 ~~+ excess air CO_2~~

Application	Absorber capture rate	Effective capture rate
CCGT	99.1%	100%
Coal/Energy from Waste	99.7%	100%
SMR	99.7%	100%

100% post-combustion capture

- Does it matter?
  - Zero residual stack CO_2 emissions is a powerful message
  - Reshaping the narrative: Hydrogen with CCS is compatible with long term climate targets on the basis of life cycle carbon intensity

International Journal of Greenhouse Gas Control

On the cost of Zero Carbon Hydrogen: A Techno-Economic Analysis of Steam Methane Reforming with Carbon Capture and Storage

--Manuscript Draft--

Manuscript Number:	JGGC-D-22-00574
Article Type:	Full Length Article
Keywords:	Carbon Capture and Storage; Zero Carbon Hydrogen; Net Zero; CCUS; Blue Hydrogen; Techno-economics
Corresponding Author:	Daniel Thomas Mullen The University of Edinburgh UNITED KINGDOM
First Author:	Daniel Thomas Mullen
Order of Authors:	Daniel Thomas Mullen
	Laura Herraiz
	Jon Gibbins
	Mathieu Lucquiaud

Process model of an SMR with 90/95/100% post-combustion capture (MEA solvent)

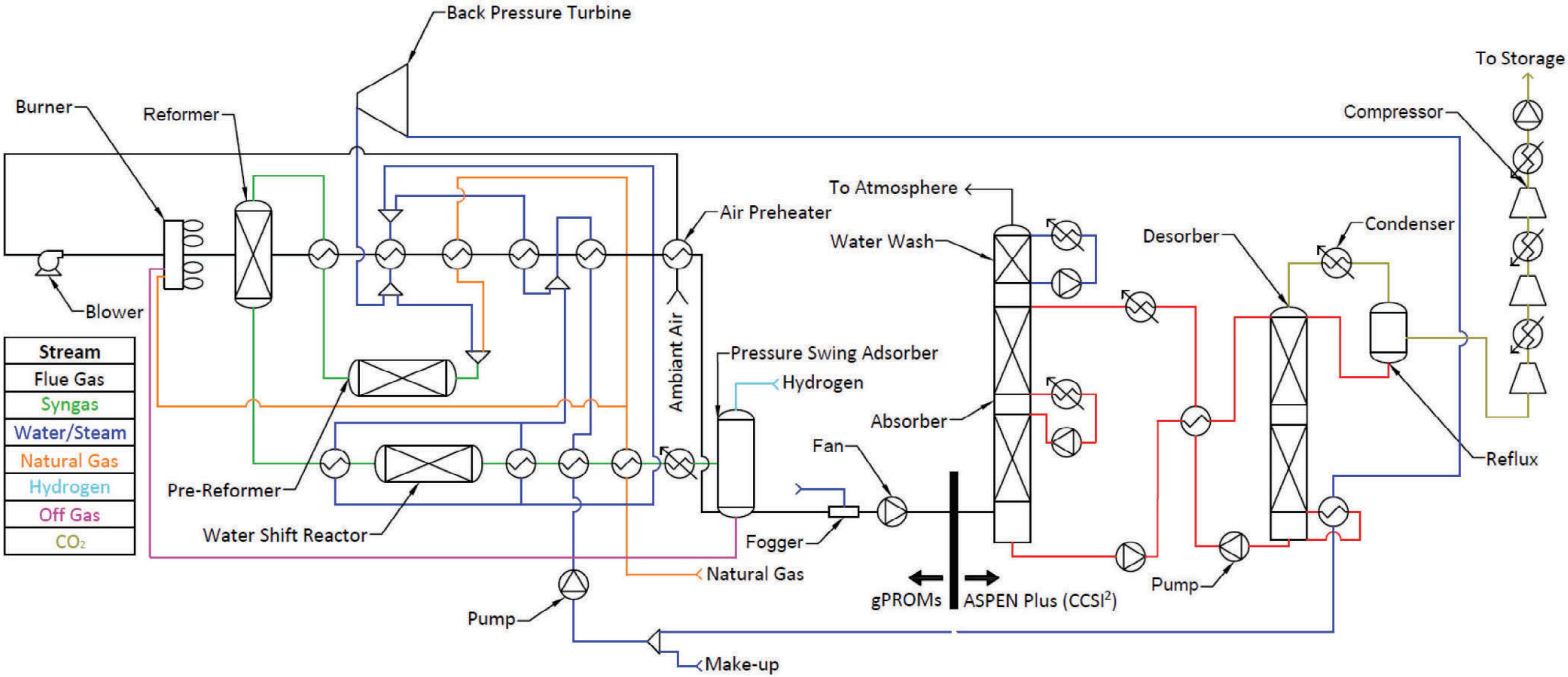


Table 7 Design and operating parameters of the CO_2 capture plant

Parameter	Unit	Zero residual emissions	5% residual emission	10% residual emission
Flue Gas				
§Flow Rate	*kg/s*	275	262	256
Inlet Temperature	*°C*	40	40	40
CO_2 Concentration	*Mole Frac*	19.4	19.9	20.2
Absorber				
Absorbers	-	1	1	1
Packing Stages	-	2	2	2
Packing Height	*m*	20	14	12
Diameter	*m*	12	12	12
Packing Volume	m^3	2262	1583	1357
Solvent Return Temp	*°C*	38	35	35
Intercooler Return Temp	*°C*	25	-	-
Absorber Flooding	*%*	78	79	79
Rich/Lean HX approach temperature	*°C*	10	10	10
Desorber				
Lean Loading	*mol CO_2/mol MEA*	0.16	0.16	0.16
Rich Loading	*mol CO_2/mol MEA*	0.466	0.469	0.469
Operating Pressure	*KPa*	210	210	210
Reboiler Temperature	*°C*	125	125	125
Specific Reboiler Duty	*GJ/tCO_2*	3.67	3.62	3.60

Table 8 Performance assessment of a SMR plant with zero, 5% and 10% residual emission PCC.

Parameter	**Unit**	**Zero residual emissions**	**5% residual emission**	**10% residual emission**
H_2 Export (HHV)	MW_{th}	1000	1000	1000
H_2 Export	kg/s	7	7	7
House Load	MW_e	-26	-24	-23
Net Power Output	MW_e	33	30	28
Supplementary fuel	kg/s	8.7	7.9	7.5
Feedstock	kg/s	20	20	20
Total Fuel	kg/s	29	28	28
Total Fuel (HHV)	MWh_{th}/s	0.416	0.404	0.400
H_2 Production Eff (HHV)	%	66.8	68.7	69.6
CO_2 Export	kg/s	76	71	67
Specific carbon intensity of H_2	gCO_2e/MJ LHV	5.0	9.0	13.2

Class 4 estimates (-15/+35%)
Scaling from open access FEED studies by Bechtel

Table 4 Total Plant CAPEX Estimates

Item	Zero residual emissions (M£)	5% residual emission (M£)	10% residual emission (M£)
PCC EPC	503	434	415
SMR EPC	619	619	619
Connections	11	11	10
Start-up/Commissioning/Spares	56	53	52
Regulatory Costs	22	21	21
Owners Costs	79	74	72
Consultation Costs	11	11	10
Interest during construction	96	90	89
Total CAPEX	**1398**	**1312**	**1289**

Level Cost of Hydrogen at point of production

Table 9 LCOH, LCOC, CCA and CAC for Zero, 5% and 10% residual emission operation

Case	LCOH (£/MWh_{th})	LCOC (£/tCO_2)	CCA (grey-to-blue) (£/tCO_2e) HHV	CCA (gas-to-blue) (£/tCO_2e) HHV
No CO_2 abatement	43	-	-	-
10% residual emissions	63	61	89	221
5% residual emissions	64	60	88	210
Zero residual emissions	67	63	93	209

Gas price is 28 £/MWhth (HHV) or 8.2 £/MMBTU

Gas price is
28 £/MWhth (HHV)
or 8.2 £/MMBTU

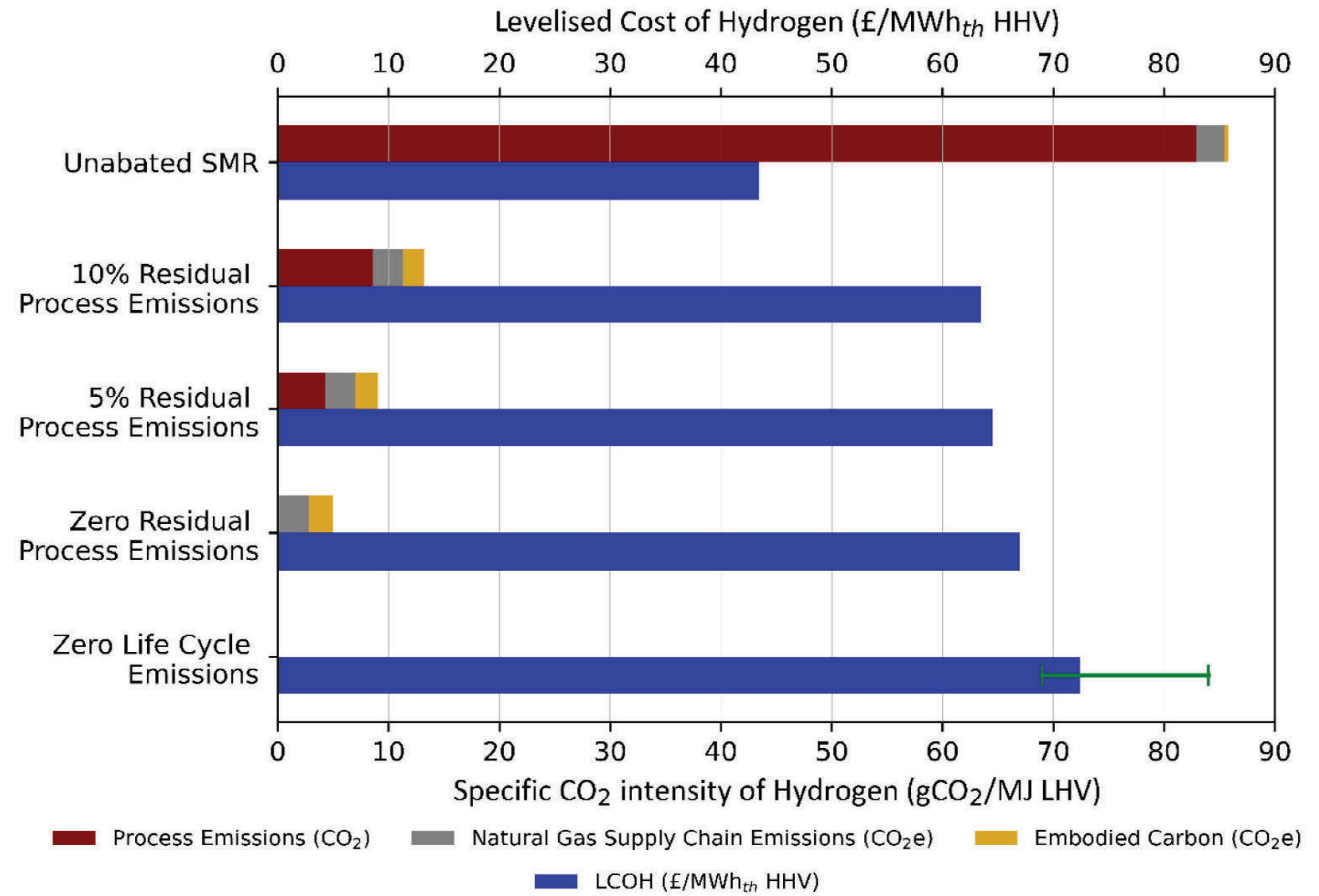


Figure 9 CO_2 intensity of H_2 production vs LCOH for a UK case (1.04% natural gas supply chain emissions and DACCS at 100 - 1000£/tCO_2)

Level Cost of Hydrogen over life cycle

Table 11 LCOH for various natural gas supply chain emissions rates over the range of DACCS cost estimates

Case	Natural Gas supply chain emission rate (% fuel supplied)	LCOH £/MWh$_{th}$ HHV (DACCS Cost = 100-1000 £/tCO_2)	CCA (grey-to-blue HHV) (£/tCO_2e)	CCA (gas-to-blue HHV) (£/tCO_2e)
Low	0.20%	68-77	82-112	214-262
UK	1.04%	69-84	83-132	213-293
High	3.00%	74-101	84-175	211-358

Gas price is 28 £/MWhth (HHV) or 8.2 £/MMBTU

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Towards net-zero compatible hydrogen from steam reformation — Techno-economic analysis of process design options

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[c] Department of Mechanical Engineering, University of Sheffield, 40 Leavy Greave Road, Sheffield, S3 7RD, UK

Contribution and aims of this study

We combine detailed process modelling with an integrated life cycle assessment (LCA) and cost model to show that process design choices dramatically affect cradle-to-gate emissions intensity of hydrogen production from SRNG. We assess four combinations of CO_2 capture and burner fuel (Fig. 2).

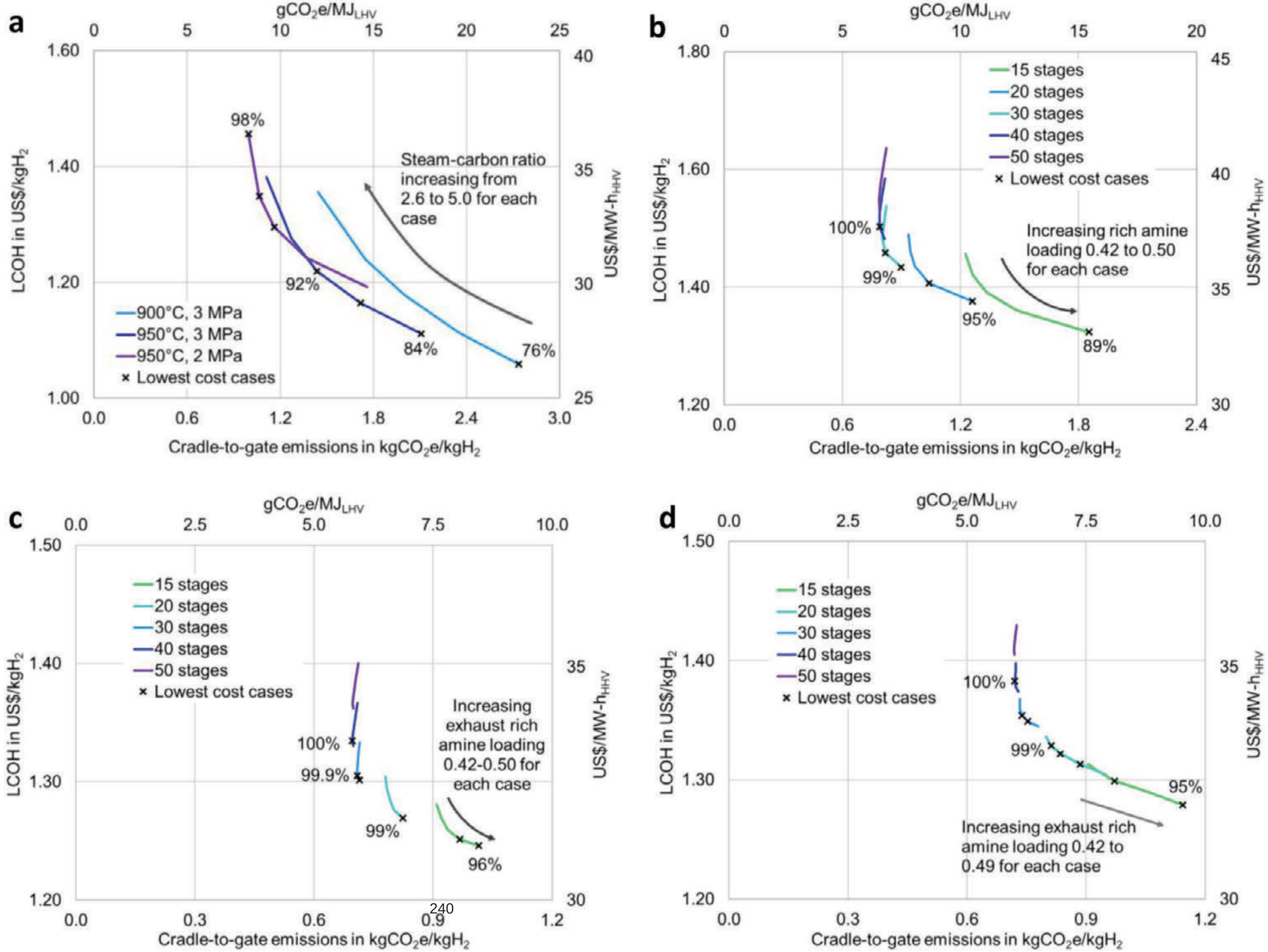
- syngas-only capture with decarbonised syngas as fuel
- exhaust-only capture with NG as fuel
- syngas-and-exhaust capture with NG as fuel
- syngas-and-exhaust capture with decarbonised syngas as fuel

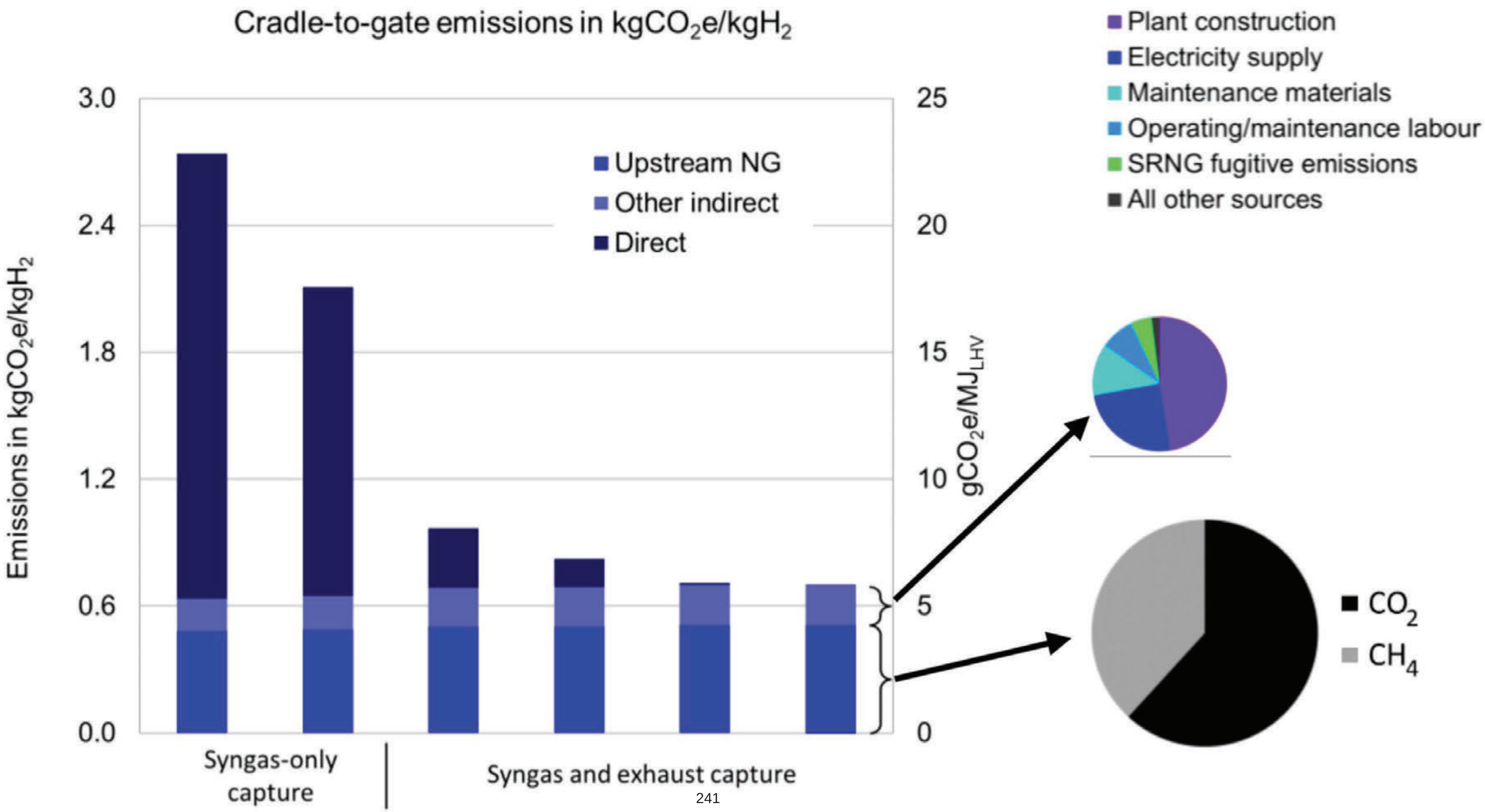
Three different GHG emission factors for NG supply were evaluated based on published literature and government data (Supplementary Note 1): 7 GE production practices [30] (3.1 gCO_2e/MJ), average BC production [31,32] (5.6 gCO_2e/MJ), and average BC production with reported methane emissions increased by 80% (6.6 gCO_2e/MJ) based on the findings of Tyner and Johnson [33].

Impact of process design conditions on LCOH and cradle-to-gate GHG emissions

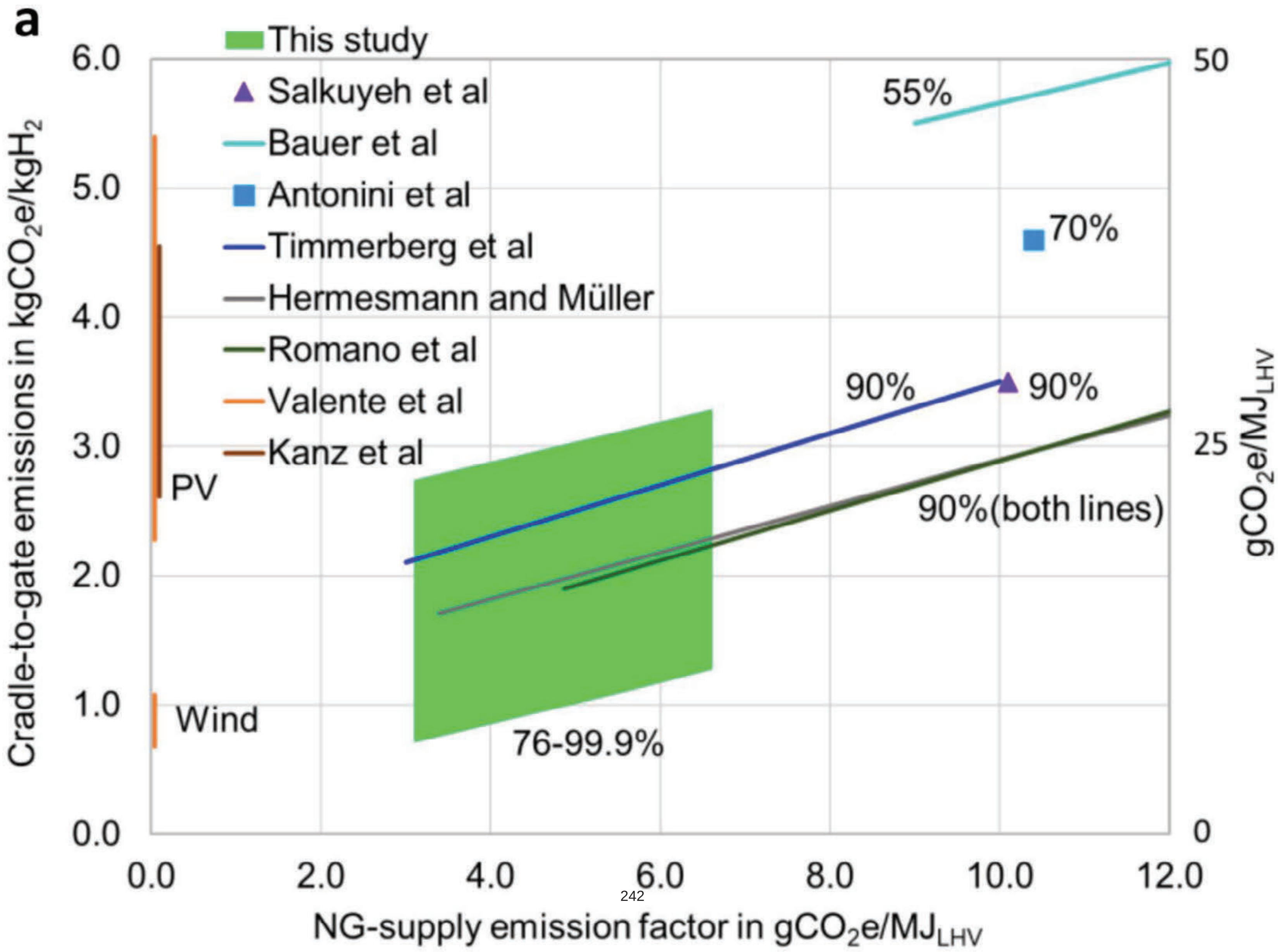
7 GE production practices

NG at 2$/GJHHV





Cradle-to-gate emissions in kgCO2e/kgH2
Emissions in kgCO2e/kgH2
gCO2e/MJLHV
3.0
2.4
1.8
1.2
0.6
0.0
25
20
15
10
5
0
Upstream NG
Other indirect
Direct
Syngas-only capture
Syngas and exhaust capture
Plant construction
Electricity supply
Maintenance materials
Operating/maintenance labour
SRNG fugitive emissions
All other sources
CO2
CH4


a
This study
Salkuyeh et al
Bauer et al
Antonini et al
Timmerberg et al
Hermesmann and Müller
Romano et al
Valente et al
Kanz et al
55%
70%
90%
90%
90%(both lines)
76-99.9%
PV
Wind
Cradle-to-gate emissions in kgCO$_2$e/kgH$_2$
gCO$_2$e/MJ$_{LHV}$
NG-supply emission factor in gCO$_2$e/MJ$_{LHV}$
0.0
1.0
2.0
3.0
4.0
5.0
6.0
2.0
4.0
6.0
8.0
10.0
12.0
0
25
50

Low-cost zero carbon hydrogen with CCS

1) Minimise stack residual emissions – design for >99% capture rate

    Low lean loading, additional packing

2) Implement best practice to minimise supply chain emissions

    Room for improvement in upstream emissions

3) Start-up and shut down emissions (power plants)

4) Use NETs to compensate for 1), 2) and 3)

QUESTIONS?

Breakout Session 2: Blue/green hydrogen

B2.1. Some reflections on the “hydrogen economy.”

Niall Mac Dowell (Imperial College London)

Imperial College London

Some reflections on the "hydrogen economy"

Niall Mac Dowell

Imperial College London

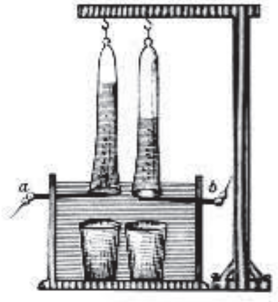
niall@imperial.ac.uk


H
2
HYDROGEN
ENERGY STORAGE

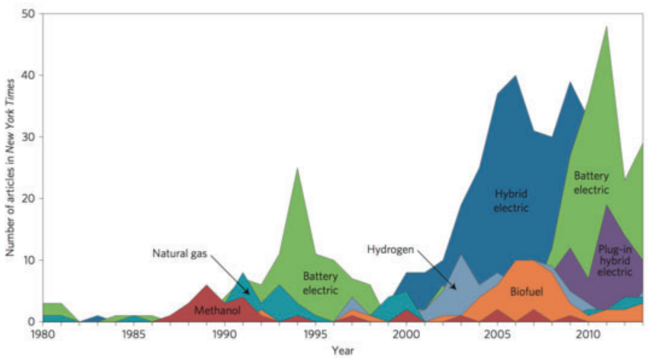
H_2 – old news, rebottled?

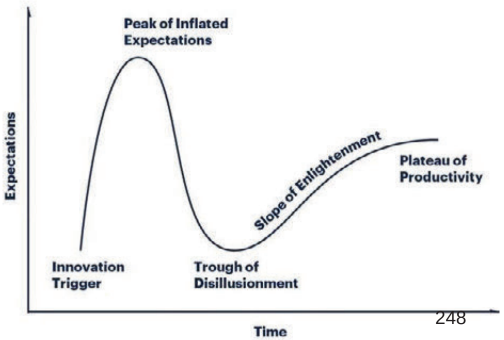
- Electrolytic H_2 production first demonstrated in 1789,
- Industrial demonstration in 1888,
- Scaled to 100 MW in 1902, via hydroelectricity in Canada and Norway.
- Hydrocarbon reforming developed in 1868,
- Commercially deployed in the 1910s,
- Benefited from historically low natural gas prices,
- Can potentially deliver low carbon H_2 via combination with CCS.

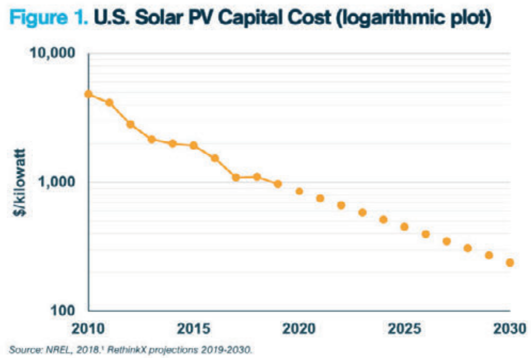
Hydrogen hype cycles?



- Over the course of the last century (1920 – 2021), hydrogen hype cycles have come and gone, usually fuelled by promises of “too cheap to meter” electricity.
- This “free power” was originally to come from nuclear power (see Lewis Strauss, 1954), and now, potentially, renewable energy.



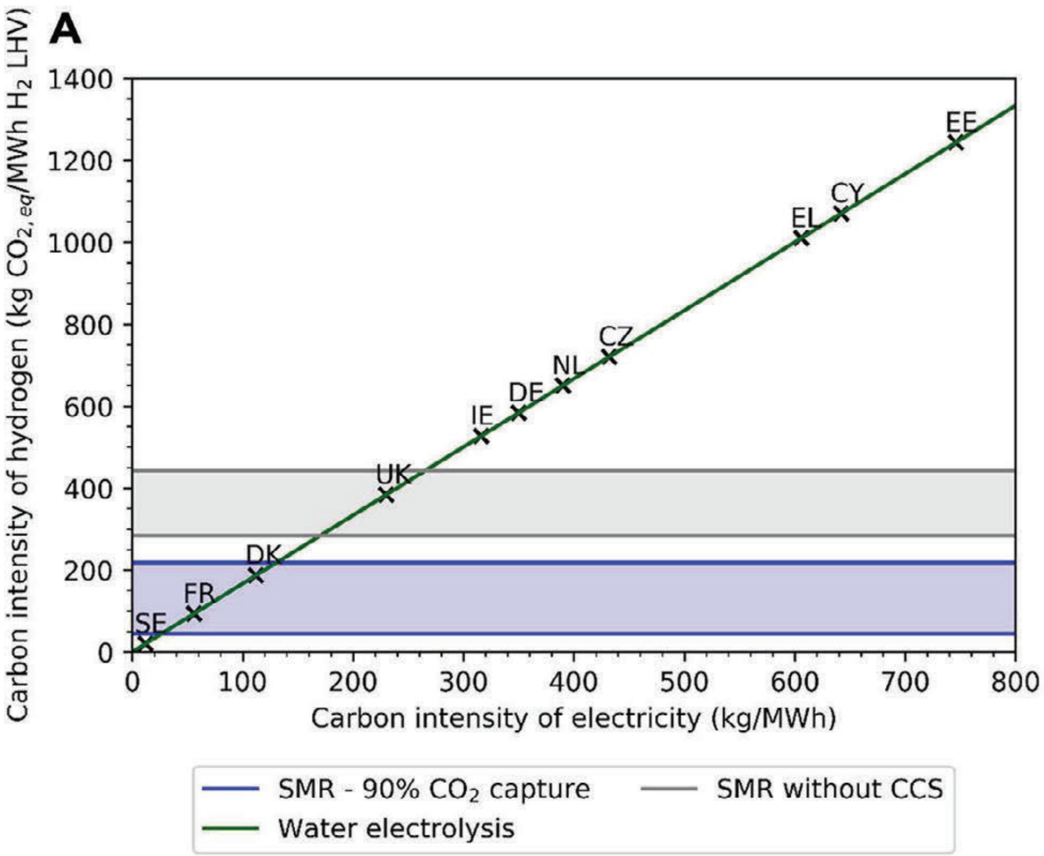


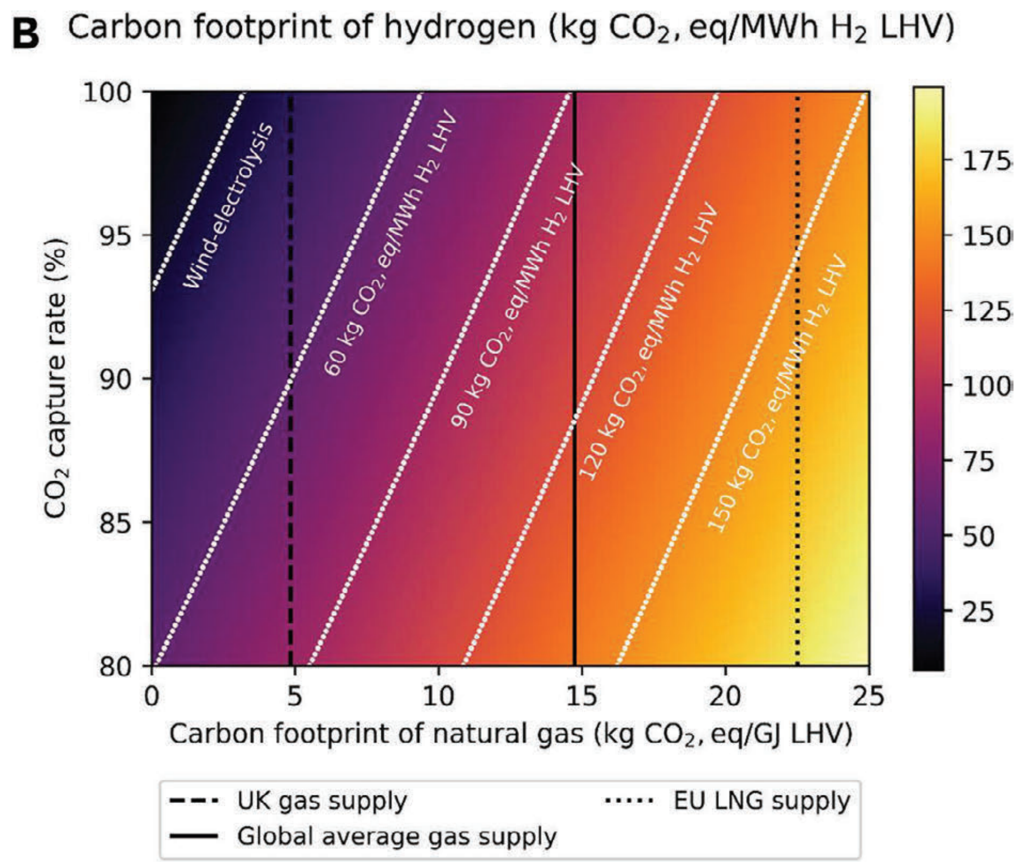


https://www.greencarcongress.com/2016/03/20160302-sperling.html

https://theconversation.com/sun-and-wind-could-finally-make-electricity-too-cheap-to-meter-34166

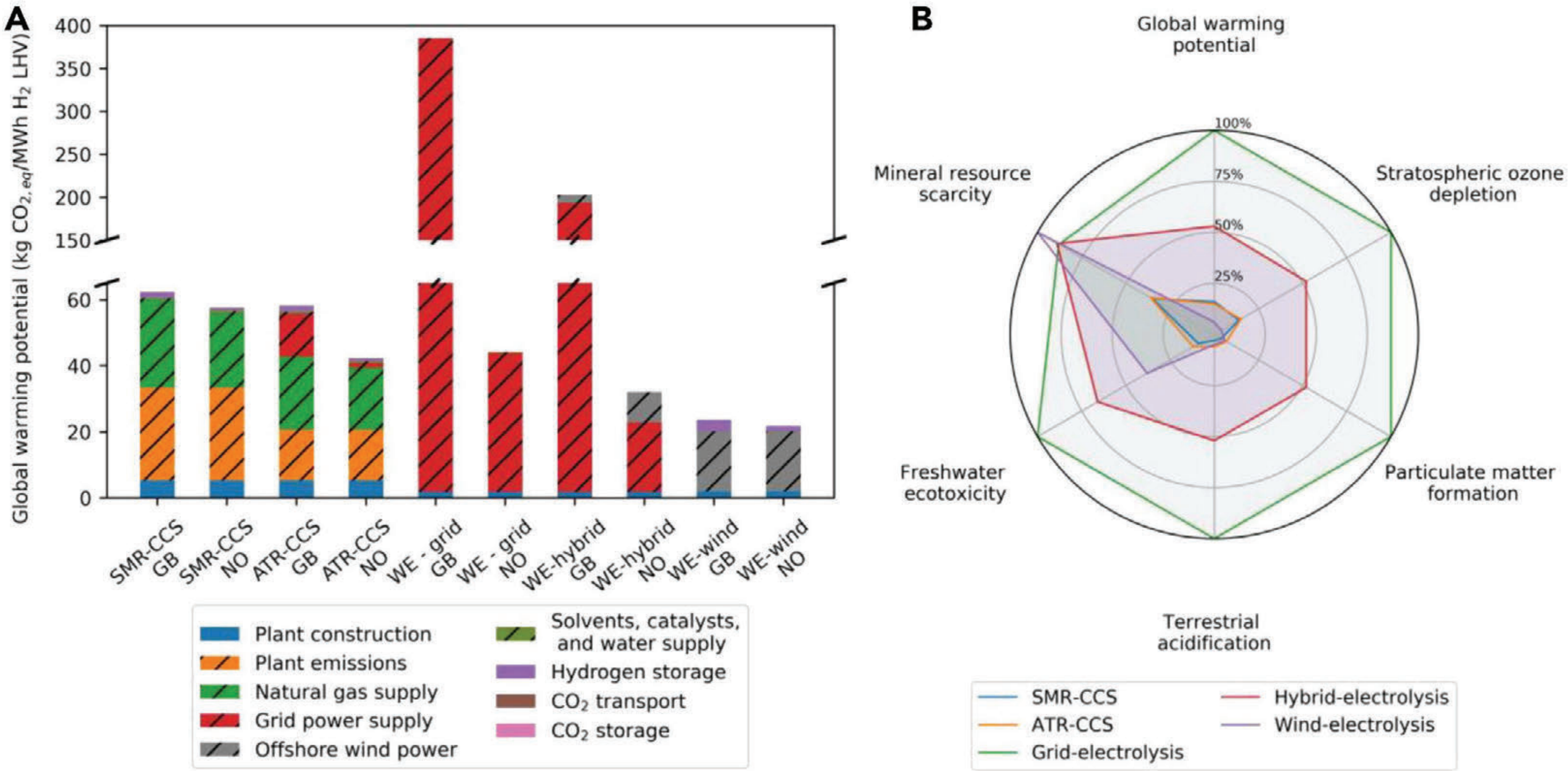
Comparing blue and green hydrogen





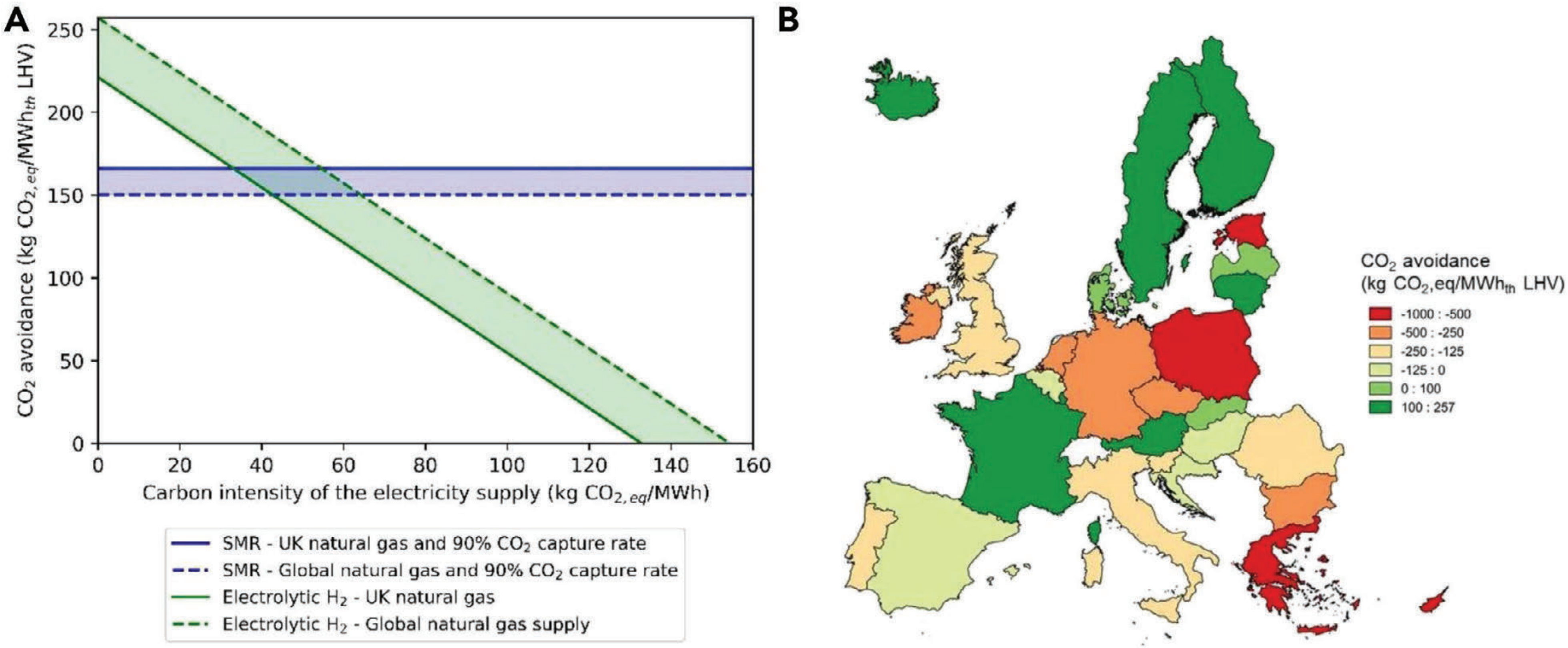
Mac Dowell, et al., Joule, 2021, 5(10), 2524 - 2529

There is more to the environment than carbon



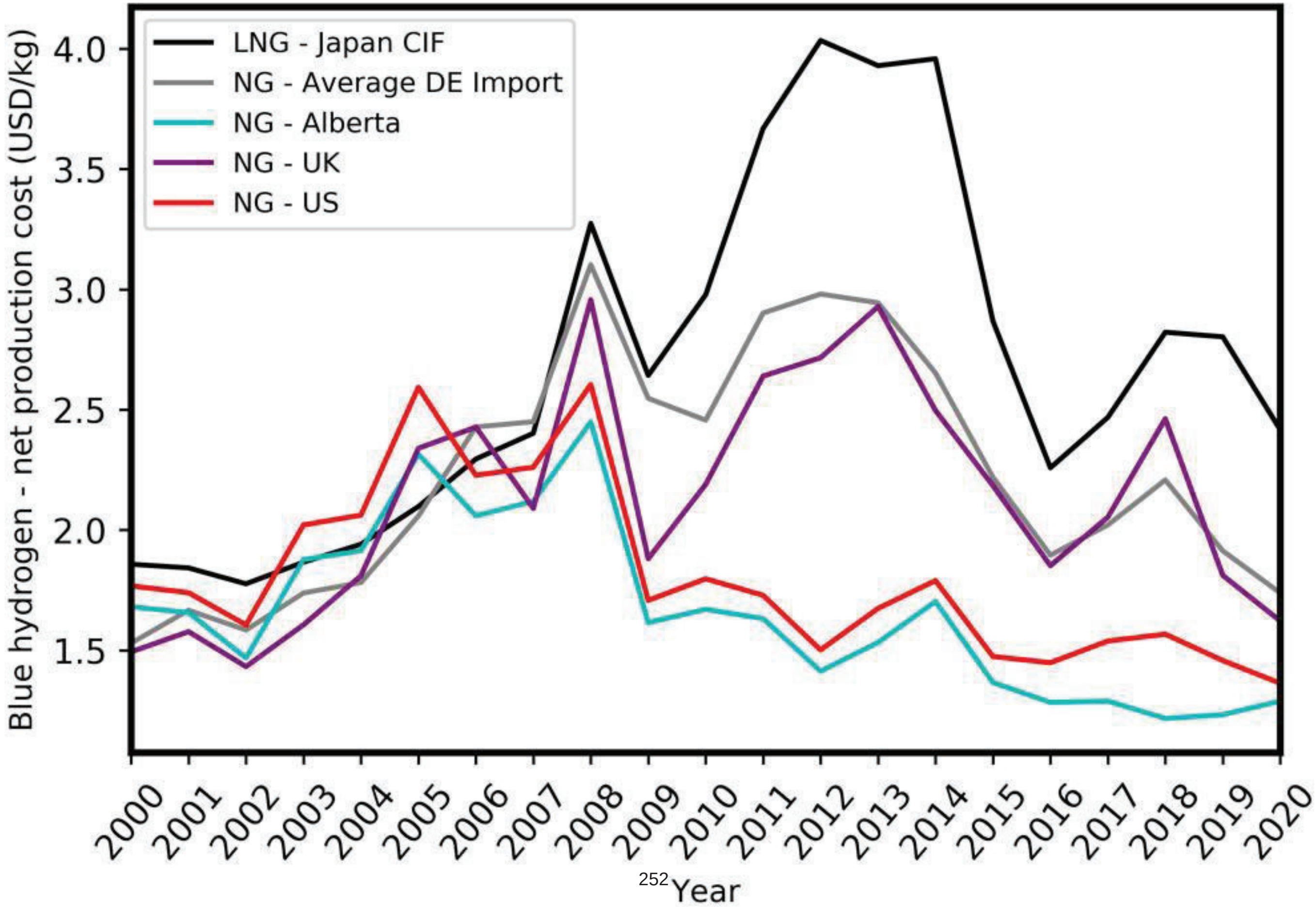
Mac Dowell, et al., Joule, 2021, 5(10), 2524 - 2529

Consider the opportunity cost

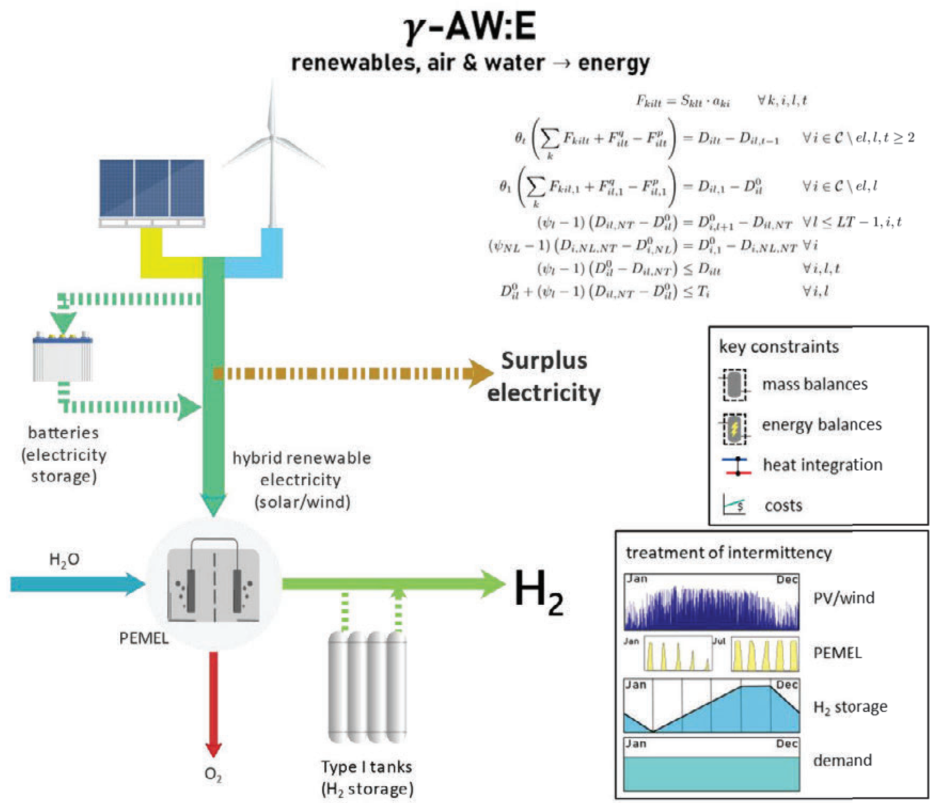


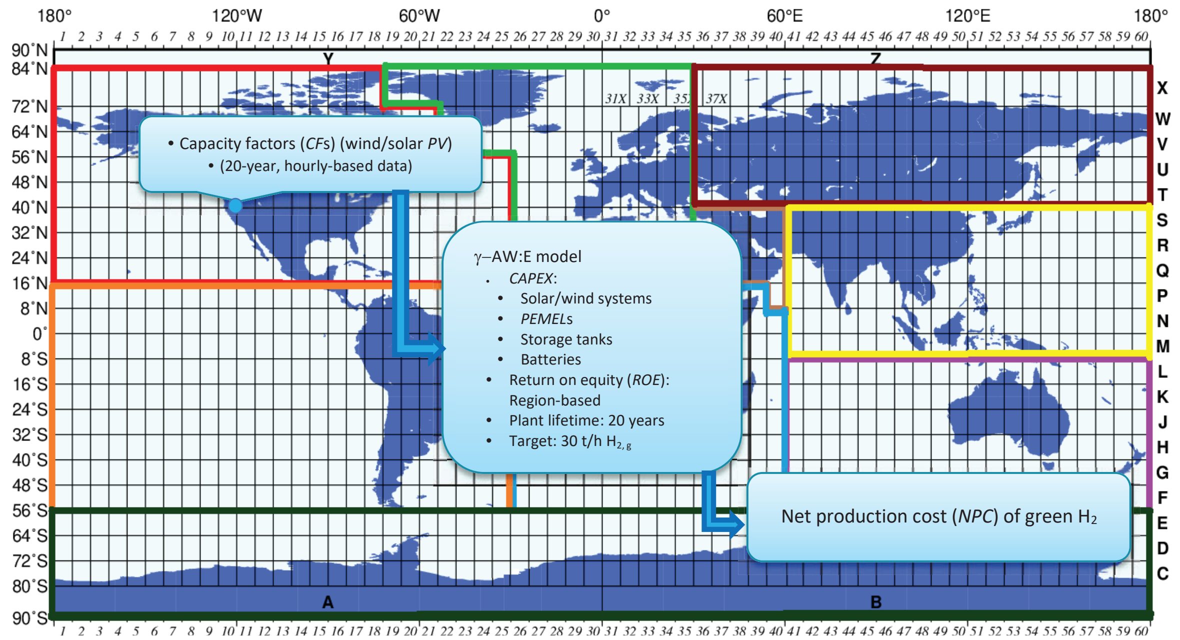
Mac Dowell, et al., Joule, 2021, 5(10), 2524 - 2529

Cost of blue hydrogen…



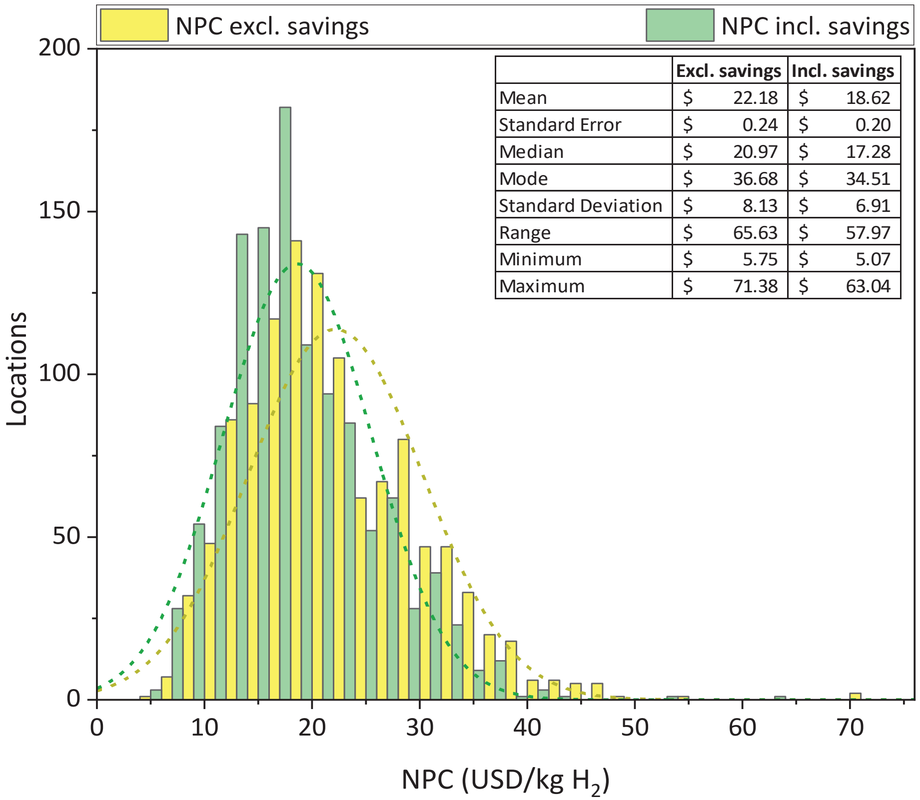
“Cheap” green hydrogen?



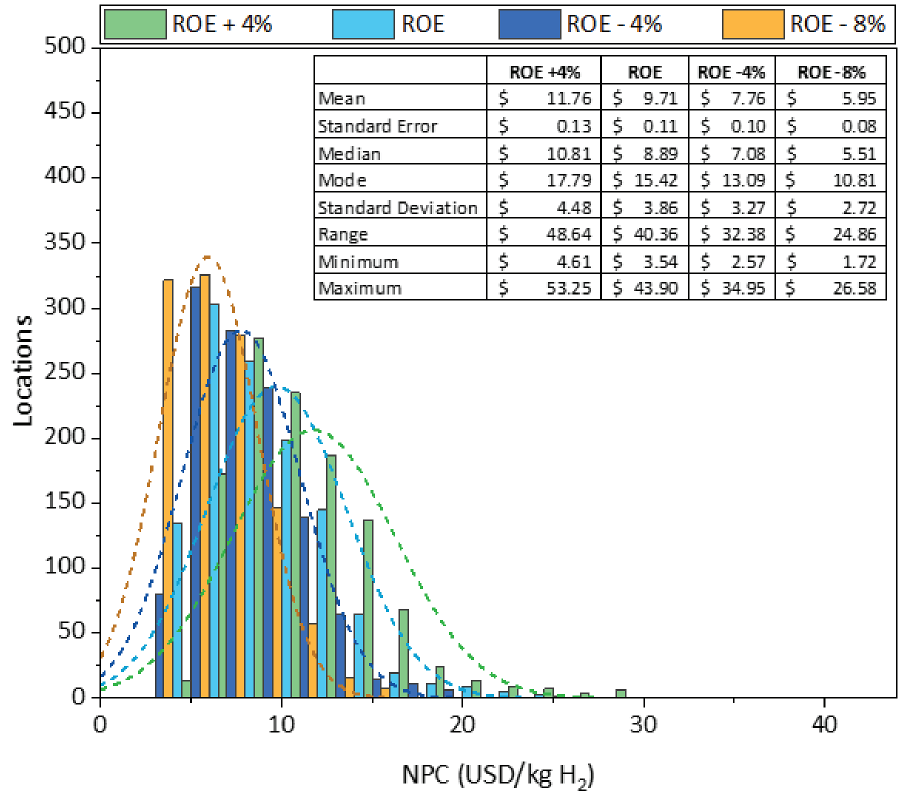


Ganzer and Mac Dowell, SEF, 2020, Freire Ordóñez, et al., Joule, 2023 (submitted)

Possible costs of reliable green hydrogen



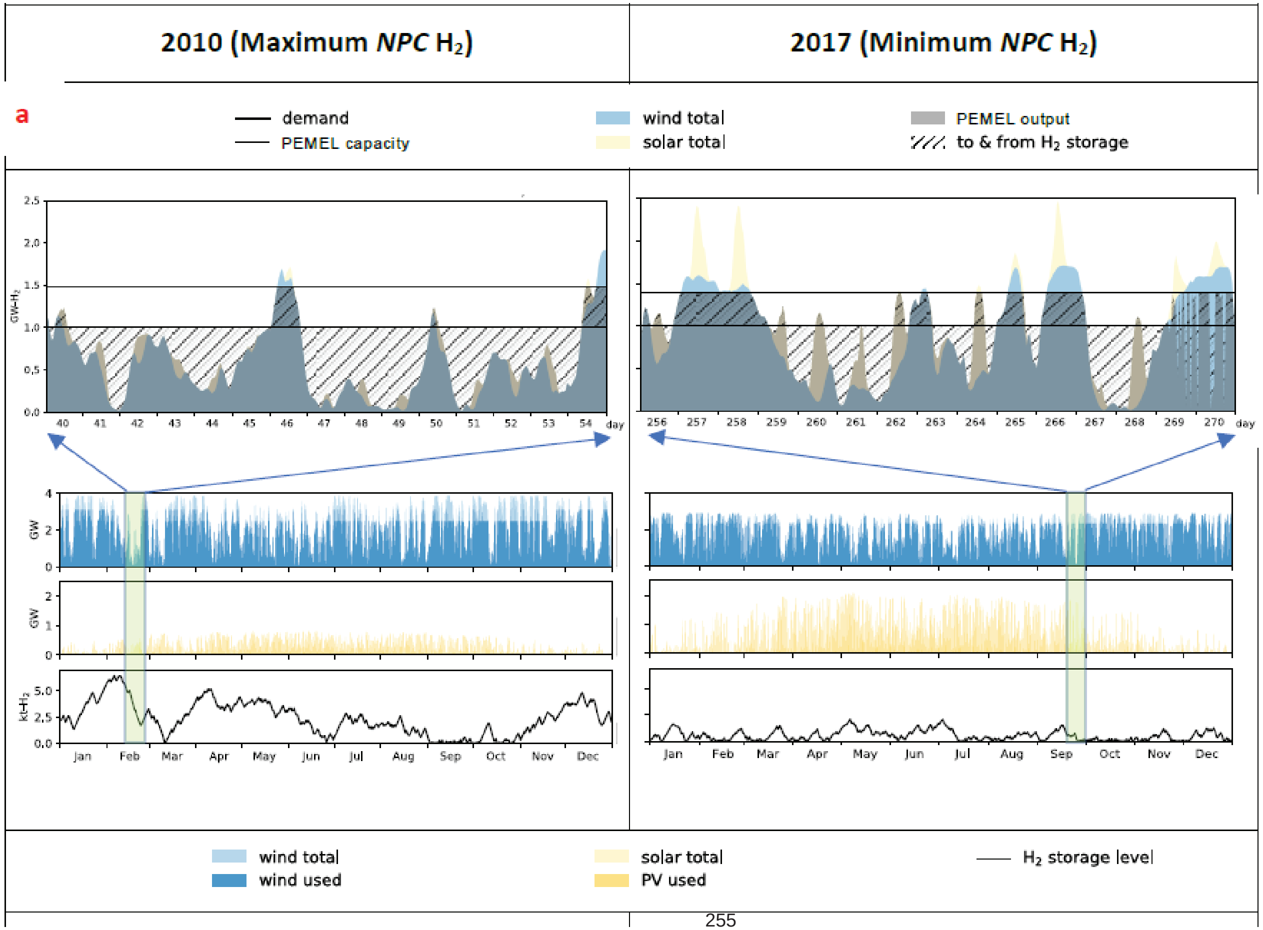
	Excl. savings	Incl. savings
Mean	$ 22.18	$ 18.62
Standard Error	$ 0.24	$ 0.20
Median	$ 20.97	$ 17.28
Mode	$ 36.68	$ 34.51
Standard Deviation	$ 8.13	$ 6.91
Range	$ 65.63	$ 57.97
Minimum	$ 5.75	$ 5.07
Maximum	$ 71.38	$ 63.04



	ROE +4%	ROE	ROE -4%	ROE -8%
Mean	$ 11.76	$ 9.71	$ 7.76	$ 5.95
Standard Error	$ 0.13	$ 0.11	$ 0.10	$ 0.08
Median	$ 10.81	$ 8.89	$ 7.08	$ 5.51
Mode	$ 17.79	$ 15.42	$ 13.09	$ 10.81
Standard Deviation	$ 4.48	$ 3.86	$ 3.27	$ 2.72
Range	$ 48.64	$ 40.36	$ 32.38	$ 24.86
Minimum	$ 4.61	$ 3.54	$ 2.57	$ 1.72
Maximum	$ 53.25	$ 43.90	$ 34.95	$ 26.58

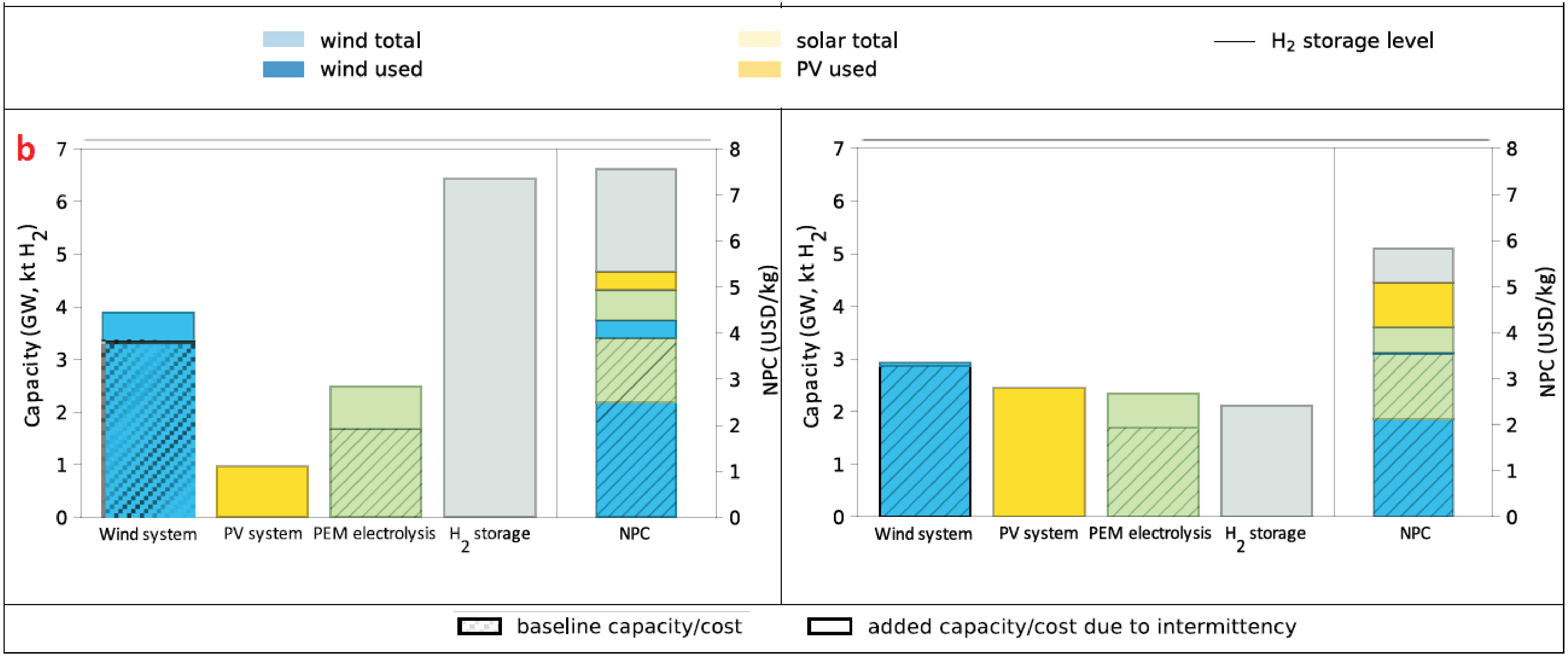
Freire Ordóñez, et al., Joule, 2023 (submitted)

Cost of intermittency



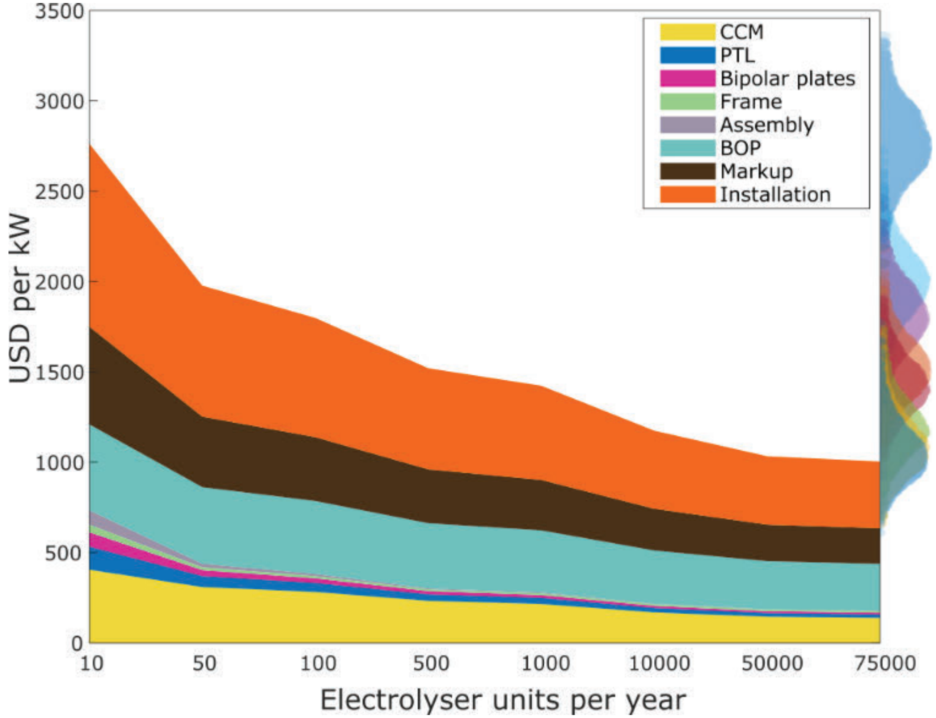
Freire Ordóñez, et al., Joule, 2023 (submitted)

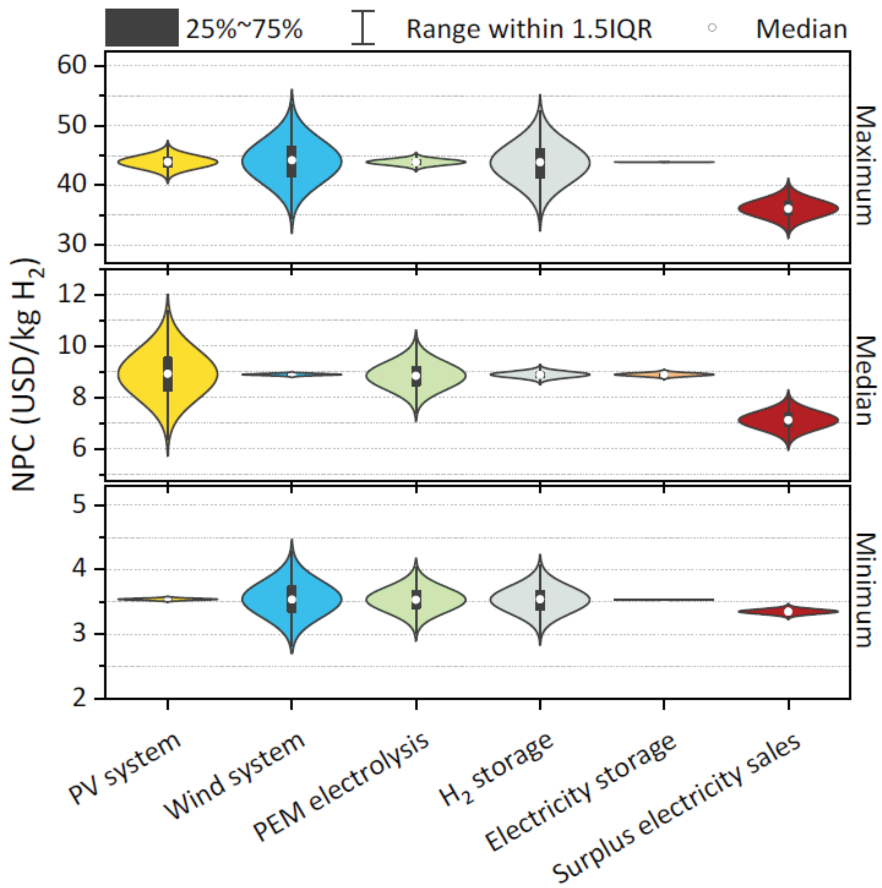
Cost of intermittency



Freire Ordóñez, et al., Joule, 2023 (submitted)

Drivers of $H_{2,g}$ cost reduction





Freire Ordóñez, et al., Joule, 2023 (submitted)

Conclusions

- Presenting the basic challenge of the net zero transition as an "either or" choice is a fundamental mistake.
- Attainable goals should be defined and linked in a way that is sustainable in the context of a broader national, regional, or international political process.
- Arguments about "the best" technology are currently a distraction. We should welcome all possibilities that enable decarbonisation.
- Move away from "colours" and focus on CI scores.
- Building confidence across the value chain is key.

Some questions

- Are there cost-reduction synergies between “blue” and “green” hydrogen?
  - The need to store hydrogen is likely common to both
- Will fugitive CH_4 emissions and LNG costs rule out blue H_2 in EU?
  - Green taxonomy requires 100 kg/MWh
- Can we scale the green supply chain without breaking it?
- At what point can we justify using “additional” green/low carbon/renewable power to produce hydrogen as opposed to displacing, e.g., coal power?

Breakout Session 3: Onshore transport and storage costs,

B3.1. Outlook for onshore transportation and storage costs.

Candice Paton (Enhance Energy)

Outlook for Onshore

Transportation and Storage Costs

Candice Paton | Vice President, Corporate Affairs

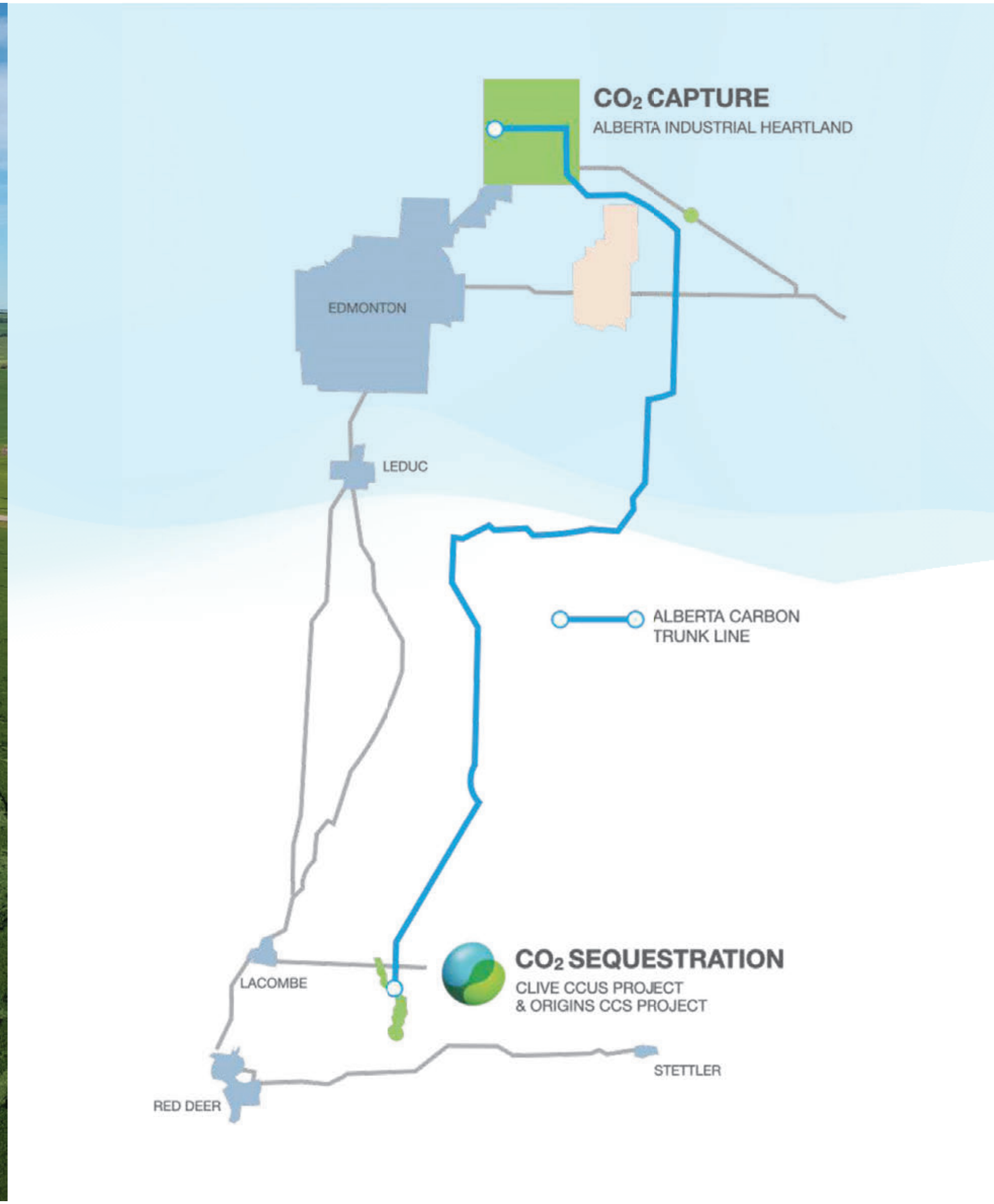
7th IEAGHG CCS Cost Network Workshop

enhance

Carbon Utilization and Storage

Over 4.0 million tonnes CO_2 emissions permanently sequestered

enhance



CO_2 CAPTURE
ALBERTA INDUSTRIAL HEARTLAND
EDMONTON
LEDUC
ALBERTA CARBON
TRUNK LINE
CO_2 SEQUESTRATION
CLIVE CCUS PROJECT
& ORIGINS CCS PROJECT
LACOMBE
STETTLER
RED DEER

Land Acknowledgement

Treaty Six

Enhance Energy acknowledges that we operate our Clive Sequestration project on Treaty 6 territory—the traditional and ancestral territory of the Cree, Dene, Blackfoot, Saulteaux and Nakota Sioux, and the Otipemisiwak Métis Nation.

We acknowledge the many First Nations, Métis and Inuit who have lived in and cared for these lands for generations.

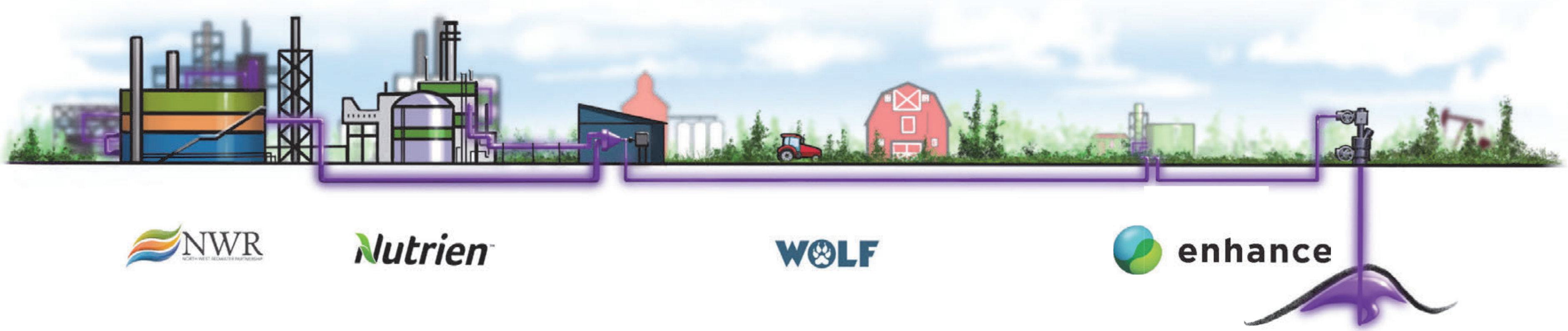
The ACTL Project

Collaboration across the carbon management value chain

CO_2 Capture

CO_2 Transportation

CO_2 Sequestration



NWR

Nutrien

WOLF

enhance

Permanent CO_2 Sequestration

Alberta

Natural Resources Canada

Ressources naturelles Canada

Pathways

origins

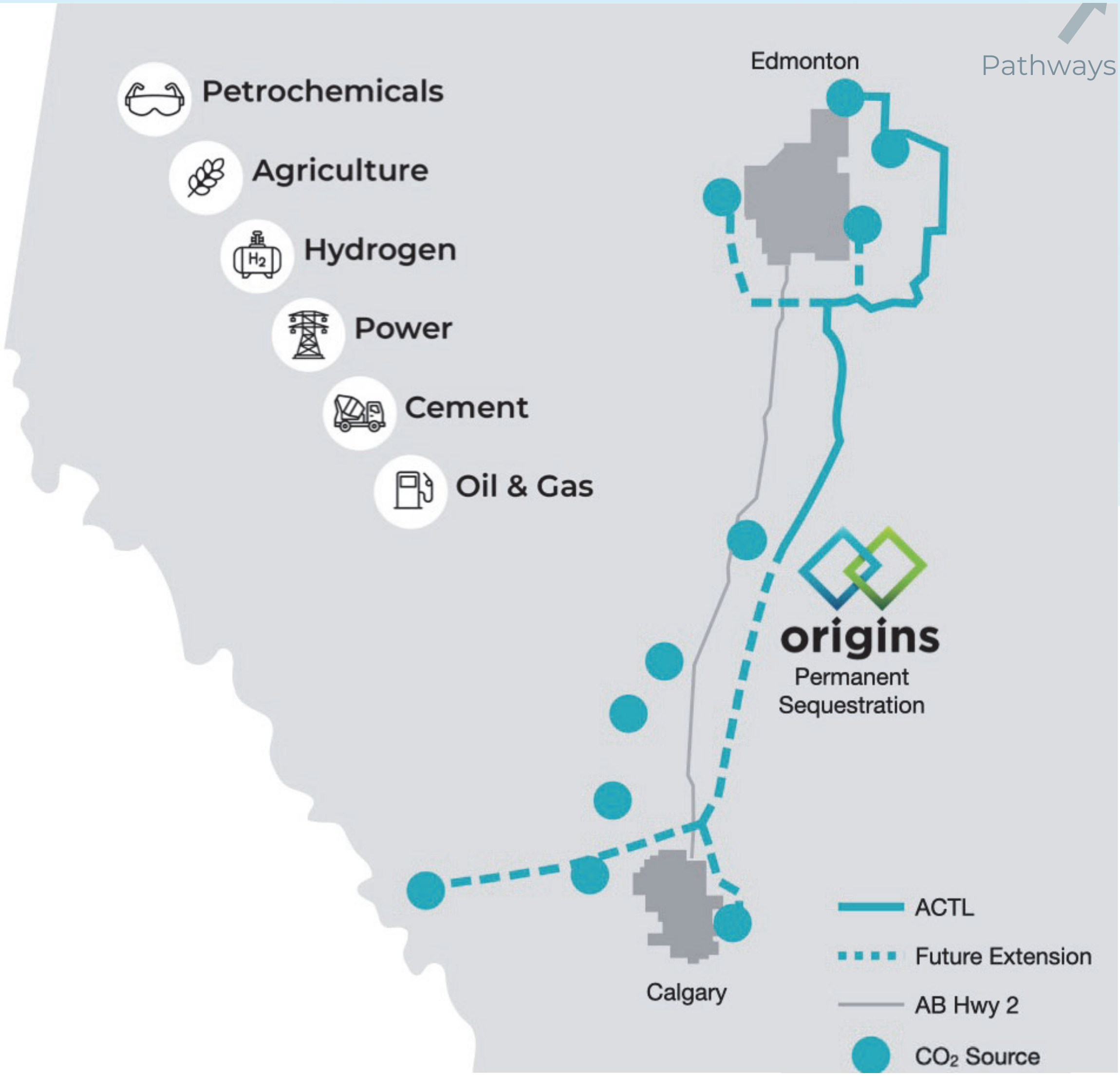
Open-access & scalable

Multi-sector, multi-geography service

Sequestration certainty

Low-cost service

Carbon management ecosystem



Knowledge Sharing

Open Alberta CCUS Knowledge Sharing:
https://open.alberta.ca/dataset?tags=CCS+knowledge+sharing+program

CSA Alberta Emissions Offset Registry
https://alberta.csaregistries.ca/GHGR_Listing/AEOR_Listing.aspx

Alberta CCUS Tenure Program:
https://www.alberta.ca/carbon-capture-utilization-and-storage-hub-development-process.aspx

Outlook for Onshore

Transportation and Storage Costs

Costs

Key challenges and opportunities in onshore CCUS

- What are the significant drivers behind costs of transport and storage with respect to:
    - Regulatory processes
    - Risk/liability management including MMV
    - Target geologies
    - Target geographies

Business Models

Key challenges and opportunities in onshore CCUS

- What are the differences between onshore and offshore CCUS business models?
- How are risks and long-term liabilities managed? How are these shared across the value chain?
- Open-access and transparency: how do these principles play a role? Are there roles for regulation of different parts of the value chain?

Interactions

Key challenges and opportunities in onshore CCUS

- What are key considerations and mitigations to manage potential project interactions for onshore CCUS?
- How will onshore CCUS projects interact with other energy transition development opportunities? Where are there synergies, where might conflicts exist?

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CHELTENHAM, UK
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Evaluating technology options to mitigate greenhouse gas emissions

IEA Greenhouse Gas R&D Programme

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Cheltenham, Glos. GL51 6SH, UK

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