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IEAGHG

Proceedings: CCS Cost Network 2025 Workshop 5-6 March 2025, Houston, USA

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IEAGHG

About the IEAGHG

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

About the International Energy Agency

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

CONTACT DETAILS

Tel: +44 (0)1242 802911
E-mail: mail@ieaghg.org
Internet: www.ieaghg.org

Address: IEAGHG, Pure Offices,
Cheltenham Office Park, Hatherley Lane,
Cheltenham, GL51 6SH, UK

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IEAGHG Cost Network Steering Committee

- Keith Burnard (Co-Chair) – IEAGHG
- Bill Elliott (Co-Chair) – Bechtel
- Abhoyjit Bhown – Electric Power Research Institute
- Mathilde Fajardy – International Energy Agency
- Timothy Fout – U.S. Department of Energy
- Jon Gibbins – UK Carbon Capture & Storage Research Centre
- Sean T. McCoy – University of Calgary
- Michael Monea – Monea CCS Services
- Machteld Van Den Broek – TU Delft
- Abdul'Aziz Aliyu (Secretariat) – IEAGHG

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Executive Summary

The 8th Workshop of the IEAGHG CCS Cost Network was hosted by Bechtel at their offices in Houston, Texas, on 5-6 March 2025. This in-person event convened around 50 invited experts from across industry, academia and finance for an expert-level dialogue on a range of topics relating to the cost of CCS.

The aim of the Workshop was to explore and advance the understanding of real-world cost estimation across the CCS value chain, drawing on practical insights from ongoing projects, studies and deployment experiences. The workshop also served as a forum to identify emerging cost drivers, share lessons learned, and discuss key enablers for reducing costs and de-risking investment in CCS systems globally.

Key takeaways from the workshop:

- While techno-economic analyses (TEAs) compare capture options under standardised assumptions, and provide indicative performance and cost estimates, they do not typically capture the localised impacts of "steel-in-the-ground" realities such as site constraints, permitting timelines, supply chains limitations, labour availability and integration with existing assets.
- Direct cost comparisons between projects are not advisable, as cost estimates were developed using inconsistent methodologies and assumptions. Variations exist in the definition and treatment of capital and operating costs, including differences in tax structures, cost escalation methods, inclusion of owner's costs, insurance and other financial parameters. Furthermore, project costs are heavily influenced by a range of site-specific and design-dependent factors, such as sparing philosophies, local labour rates, geotechnical conditions, ambient environment and climate-related design requirements. These variables introduce inherent complexity and reduce the comparability of cost estimates across projects.
- Offshore transport and storage (T&S) scenarios consistently exhibited the highest unit costs relative to onshore alternatives. Studies indicated that costs generally decrease with an increasing number of candidate storage sites, allowing for greater routing flexibility and more cost-optimised infrastructure development. Participants emphasised the urgent need for transparent, high-resolution cost data to guide strategic investment decisions in CO_2 transport networks.
- Costs for new-build, greenfield CO_2 pipelines are highly sensitive to location-specific parameters, including terrain, land use, permitting complexity and stakeholder engagement. Installers are unable to provide firm cost estimates without a detailed understanding of these constraints, and routing alternatives can cause significant variation in capital costs. Comprehensive and accurate cost

assessment requires upfront investment in site surveys, routing studies and stakeholder analysis.

- Financing is one of the most significant cost drivers in CCS deployment, often representing up to 50% of the total levelised cost per tonne of CO_2 captured and stored. Contributing factors include high capital intensity, inflationary pressures, interest rate volatility and the lack of long-term offtake agreements. These risks typically attract growth or structured equity investors, who demand higher returns. To reduce financial barriers and mobilise capital, targeted policy support – such as enhanced fiscal incentives for heavy industry, streamlined permitting, and robust regulatory frameworks – is essential.
- Standardisation and replication of CCS system designs, especially for mature configurations such as gas boilers and natural gas combined cycle (NGCC) retrofits, could accelerate cost reductions and de-risk financing. This approach may yield faster gains in investor confidence and commercial viability than waiting for disruptive technology breakthroughs.
- Current incentive mechanisms, which predominantly focus on capital cost support, tend to favour low-risk, commercially mature technologies. However, achieving broader cost reductions and enabling the future deployment of next-generation CCS systems will require phased and risk-tolerant investment in lower-TRL (technology readiness level) capture technologies.
- Early-stage, collaborative "storage-ready" development significantly improves project bankability. Because secure storage access is critical to CCS viability, capture developers and T&S operators should jointly invest in early geological characterisation, risk assessment and permitting activities. Advancing preparatory work on Class VI wells[1] and associated infrastructure can accelerate timelines, reduce uncertainty and improve access to financing.
- Capture rates of ≥95% are technically and economically viable, particularly when supported by robust solvent management and optimised plant operation. However, pursuing 100% capture poses diminishing returns, with considerable cost and operational challenges. At these ultra-high capture levels, the majority of residual lifecycle emissions from NGCC+CCS systems stem from upstream methane leakage and gas supply emissions, highlighting the importance of sourcing low-carbon intensity natural gas.
- Integration of CCS into power plants requires careful selection of steam regeneration configurations. While steam extraction offers the highest thermodynamic efficiency, it imposes operational inflexibility and extended start-

[1] Class VI wells are used to inject CO_2 into deep underground rock formations (typically saline aquifers) for permanent storage, in a manner that ensures protection of underground sources of drinking water (USDWs).

up times. In contrast, standalone CHP systems and auxiliary boilers offer improved flexibility and modularity, albeit at higher energy penalties and capital costs.

- Government intervention remains the primary enabler of CCS deployment. Jurisdictions have employed a range of policy instruments – such as carbon pricing (taxes or markets), capital subsidies, operational incentives, and regulatory mandates – to stimulate investment. Long-term political alignment and consistent policy support are critical to sustaining deployment and scaling CCS as a viable decarbonisation pathway

Overall, the workshop underscored that scaling up carbon capture and storage (CCS) will require a pragmatic integration of commercially proven technologies, targeted innovation, and cohesive policy and financial frameworks. Success will hinge on early, cross-sector collaboration across the CCS value chain, improved transparency in cost and performance data, and the adoption of adaptive, site-specific project strategies. These elements are critical to de-risking investments, optimising capital allocation, and establishing CCS as a reliable and scalable solution for achieving global decarbonisation targets.

Workshop Agenda

Day 1: Wednesday, 5 March 2025

08:45 -09:15	**Arrival and registration**
09:15 -09:30	**Welcome:** Bechtel
09:30 -11:00	**Session 1: US DOE-funded Point Source Capture FEED Studies** Co-Chairs: Timothy Fout – US DOE Bill Elliott – Bechtel The US Department of Energy has funded several Front-End Engineering Design studies over the past several years. These studies have provided significant findings regarding specific costs for capture technologies at specific sites. Many of these factors are not adequately accounted for in the development of techno-economic studies. Presentations and discussions in this session will focus on a summary/analysis of a set of DOE-supported FEED studies along with a more detailed dive into one of them. *Speakers: Sally Homsy – NETL* *Brice Freeman – MTR Carbon Capture*
11:00-11:30	**Break**
11:30-13:00	**Session 2: Transport Costs** Co-Chairs: Machteld van den Broek – T U Delft Keith Burnard – IEAGHG The costs associated with the critical transport component of the CCS value chain are frequently underestimated in studies. Reliable cost estimates remain challenging to obtain, and data from real projects often reveal significantly higher costs than initial projections. This session seeks to shed light on existing cost data from real-world projects, explore the limitations of current data, and identify opportunities for improvement, aiming to deepen understanding of CO_2 transport costs across different modes and support more accurate future estimations. *Speakers: Colin Laing – Xodus* *Andrew Bean – EPRI*
13:00-14:00	**Group photo followed by lunch.**

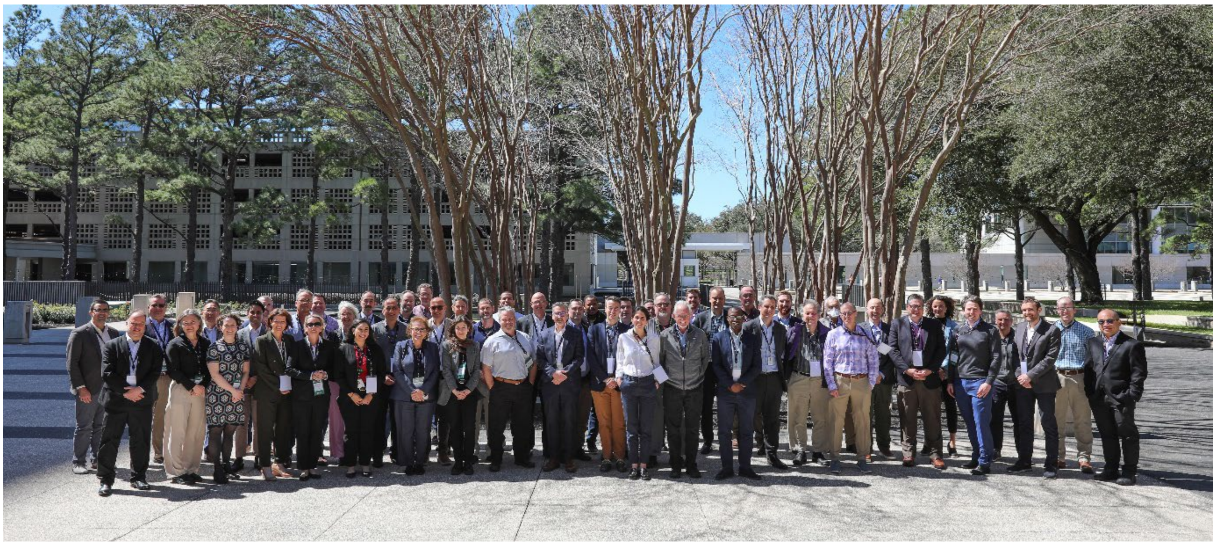
14:00-15:30	**Session 3: Realistic Financing Assumptions** Co-Chairs: Sean McCoy – University of Calgary Mathilde Fajardy – IEA The cost of financing capital intensive projects such as power and industrial facilities with CCS has a major impact on their economic viability. Moreover, the addition of technologies such as CCS that have a higher perceived risk can increase their cost of capital. As a result, governments have introduced policies that can offset the capital cost through tax credits or reduce the downside risk from price volatility. This session aims to examine the factors that influence the cost of financing for CCS. *Speakers: Jeff Brown – Stanford University* *Alexander Shelby – Barclays*
15:30-16:00	**Break**
16:00-17:30	**Session 4: Bases for CCS Costs Internationally** Co-Chairs: Mathilde Fajardy – IEA Sean McCoy – University of Calgary Most operating CCUS projects to date are in North America. As first-of-a-kind projects fire up in Asia and Europe, there is still little evidence as to how CCUS costs vary across regions, depending on country-specific variables that might include labour, energy, materials, and financing costs, as well as access to and cost of transport and storage infrastructure. This session aims to unpack some of the key drivers of CCUS costs with evidence from FEED studies and commissioned projects and discuss potential regional variations. *Speakers: Geoff Bongers – Gamma Energy Technology* *Shannon Timmons – CCS Knowledge Centre*
19:30	**Dinner** – Courtesy of **Bechtel**

Day 2: Thursday, 6 March 2025

09:00-10:30	**Session 5: Storage Costs Reduction**	
	Co-Chairs:	Jon Gibbins – UKCCSRC
		Mike Monea – Monea CCS Consulting
	CO_2 storage costs have typically been assumed to be a minor element in the overall cost of implementing CCS, and even a negative cost when CO_2 is sold for EOR. But anecdotal evidence is that currently the costs attributable to CO_2 storage are often significant. This session will discuss the drivers that are emerging that will ultimately impact storage toll structures, for example risk and liability, who is willing to take on what and protocols.	
	Speakers:	*Wes Peck – EERC*
		Candice Paton – Enhance Energy
		Ole Engels – Heidelberg Materials
10:30-11:00	**Break**	
11:00-12:30	**Breakouts**	
	Breakout 1:	**International CCS Drivers**
	Chair:	Machteld van den Broek – T U Delft
	Moderator:	*Hugh Barlow – GCCSI*
	Breakout 2:	**Moving towards 100% capture – is it Possible and is it Worth it ?**
	Chair:	Jon Gibbins – UKCCSRC
	Moderator:	*Jon Gibbins – UKCCSRC*
	Breakout 3:	**Impact of plant integration**
	Chair:	Abhoyjit Bhown – EPRI
	Moderator:	*Abhoyjit Bhown – EPRI*
12:30-13:30	**Lunch**	
13:30-14:30	**Closing Plenary:**	
	Chair:	Bill Elliott – Bechtel
	Concluding Remarks	
		Bill Elliott – Bechtel
		Keith Burnard – IEAGHG

Introduction

IEAGHG's 8th CCS Cost Network Workshop, hosted by Bechtel at their Energy Headquarters in Houston, the so-called Energy Capital of the World, took place on March 5–6, 2025. This invitation-only, in-person gathering convened around 50 leading experts from industry and academia, fostering a highly interactive forum for in-depth discussions on advancing real-world cost estimation across the CCS value chain.



Delegates attending the 8th CCS Cost Network Workshop

The workshop was opened with welcoming remarks from Bechtel's Bill Elliot, Operations Manager, ET, and George Whittaker, CCUS Operations Manager, which set the scene for a workshop focused on sharing expertise, challenging assumptions, and identifying practical pathways to lower CCS costs.

The workshop was conducted through five plenary sessions and three breakout discussions.

Session Summaries

Session 1: Insights from the US Department of Energy (DOE) - funded Point Source Capture Front-End Engineering Design (FEED) studies.

Sally Homsy (NETL) highlighted the impact of host plant operational mode and capacity factor on the business case for CCS. As renewable penetration increases, fossil-powered plant capacity factors may decline, affecting overall project economics. However, future incentives and policy mechanisms could support CCS-equipped plants, leading to preferential dispatching of clean power and strengthening the financial viability of these projects. **Brice Freeman (MTR Carbon Capture)** presented on the Commercial-Scale FEED Study for MTR's Membrane CO_2 Capture Process, highlighting DOE's support from early TRL lab-scale development through multiple field trials. This funding pathway culminated in the large pilot project at the Wyoming Integrated Test Centre (WITC) and has now progressed to a full-scale, full-chain demonstration, marking a significant milestone in advancing membrane-based CO_2 capture technology.

Session 2: CO_2 Transport Costs

Colin Laing (Xodus) remarked that the cost of newbuild, new-route CO_2 pipelines is heavily influenced by location-specific factors. Firm cost estimates require a clear understanding of these factors, as considerations such as road and river crossings, conflicts with existing infrastructure, and routing options all play a significant role in determining overall costs. He noted that cost estimates can vary widely at the early stages of project development and explained that a gated development process helps progressively reduce cost uncertainty by improving the accuracy of data and assumptions.

Andrew Bean (EPRI) presented findings from the U.S. Eastern Seaboard Transport and Storage Study, summarising CO_2 transport costs and exploring how CCS infrastructure could be deployed to support regional decarbonisation. The study utilised four modelling tools to estimate the integrated costs of capture, transport, and storage in the region: CO_2NCORD for capture costs, CostMAP^{PRO} for pipeline and shipping costs, SCO_2T^{PRO} for storage cost and capacity analysis, and SimCCS^{PRO} for overall integrated costs. Andrew's presentation highlighted high-level CCS deployment costs along the Eastern Seaboard, and key cost drivers that could inform future infrastructure planning.

Pre-workshop networking

Session 3: Realistic Financing Assumptions

Jeff Brown (Stanford) and Alexander Shelby (Barclays), explored the financing challenges of capital-intensive CCS projects. They highlighted how perceived risks elevate capital costs and examined how government policies, such as tax credits, could mitigate these barriers, offering a critical lens on CCS economics. Jeff delivered a passionate and well-articulated presentation on 'What Factors Drive Finance Costs?', providing a clear breakdown of the key influences shaping CCS investment decisions and the financial hurdles that need to be addressed for wider deployment.

Session 4: Basis for CCS Costs Internationally

This session featured presentations by **Geoff Bongers (Gamma Energy Technology)** and **Shannon Timmons (CCS Knowledge Centre)**. Geoff compared decarbonisation pathways for Australia and Japan, highlighting how regional factors shape cost-effective strategies. While both regions experience rising costs as decarbonisation approaches 100%, their optimal technology mix differs based on geography. Shannon shared key learnings from Emissions Reduction Alberta's Carbon Capture Kickstart (CCK) Program, emphasising the importance of Levelised Cost of Capture (LCOC) and Levelised Cost of Avoidance (LCOA) as critical metrics in determining project feasibility. To support broader adoption, a dedicated LCOC and LCOA calculator has been developed and will be made publicly available, enabling stakeholders to conduct their own assessments and enhance CCS investment decision-making.

Session 5: Storage Cost Reduction

The second day opened with **Session 5:** *Storage Cost Reduction*. **Candice Paton (Enhance Energy)** presented on the development of CCS hubs in Alberta, like Enhance's Origins project, discussing the key drivers that potentially impact storage costs and emphasising the importance of understanding the limitations and assumptions made in the evaluation process. She highlighted the need for shared risk and liability between emitters and storage providers, stressing the importance of clear agreements and a thorough understanding of risks in CO_2 storage projects. **Wes Peck (EERC)** provided insights into CCUS well drilling costs in North Dakota, highlighting key cost drivers of CCS wells under different scenarios. He discussed how costs vary depending on whether a project targets a single formation or multiple formations of interest, as well as the impact of depth on overall expenses. Another critical cost consideration was the choice between transitioning a stratigraphic test well into a Class VI injection/monitoring well or plugging and abandoning (P&A) the stratigraphic test well, each with distinct economic implications for project feasibility. **Ole Engels (Heidelberg Materials)** discussed CCS costs based on Heidelberg's experience, highlighting its portfolio of CCS and CCU projects, some of which are end-to-end. He emphasised how storage properties can drive significant economic opportunities, further exploring the relationship between storage injectivity and capacity.

Breakout Summaries

Following the five technical sessions, the second day featured three breakouts:

Breakout 1: International CCS Drivers

The first breakout sessions was chaired by **Machteld van den Broek (T U Delft)** and moderated by **Hugh Barlow (GCCSI)**, who set the stage with a well-thought-out presentation, posing key questions on international CCS drivers, including what has been working well in different regions, what challenges persist, how countries can create long-term certainty, and the role of the private sector in driving CCS deployment. This led to an engaging and immersive discussion on regional CCS challenges and opportunities.

Breakout 2: Moving towards 100% capture – is it Possible and is it Worth it?

Breakout session 2 was chaired by **Jon Gibbins (UKCCSRC)**, while **Ryan Cownden (University of Sheffield)** and **Simon Roussanaly (SINTEF Energy)** shared insights on the viability and value of achieving 100% CO_2 capture. Their presentations sought to address if 100% capture is worth it? sparking an engaging discussion on whether fully capturing fossil CO_2 is a realistic goal considering the cost challenges associated with reaching 100% capture concerning the lifecycle economics of a plant, weighing the trade-offs between technical feasibility and economic viability.

Breakout 3: Impact of Plant Integration

The third breakout session was chaired by **Abhoyjit Bhown (EPRI)**, who explored different methods of supplying thermal energy for solvent regeneration in CO_2 capture. In the context of plant integration, Abhoyjit delved deeper into environmental considerations crucial for the successful deployment of CCS, highlighting key factors such as air quality, water usage, land impact, and public engagement. These broad themes fostered an in-depth discussion, emphasising the need for a holistic approach to CCS implementation that balances technical feasibility with environmental and societal concerns.

Technical Sessions

Session 1: US Department of Energy-funded Point Source Capture Front-End Engineering Design (FEED) Studies

Co-chairs:
Timothy Fout, US DOE; Bill Elliott, Bechtel

Speakers:
Sally Homsy, NETL; Brice Freeman, MTR Carbon Capture

The US Department of Energy has funded several Front-End Engineering Design (FEED) studies over the past several years. These studies have provided significant findings regarding specific costs for capture technologies at specific sites. Many of these factors are not adequately accounted for in the development of techno-economic studies. Presentations and discussions in this session focused on a summary/analysis of a set of DOE-supported FEED studies along with a more detailed dive into one of the FEED studies.

Presentation 1

Review of DOE-Sponsored FEED Studies for Retrofitting Existing Fossil Power Plants with Carbon Capture Technology

Sally Homsy, NETL

Sally Homsy's (NETL) presentation focused on several DOE sponsored FEED studies on retrofitting existing US power fleet with capture since 2019. Study reports are available on OSTI.gov with links included at the end of this summary. NETL also recently published an article in the International Journal of Greenhouse Gas Control (Homsy *et al.*, 2025) on insights from FEED studies and remaining knowledge gaps. The link for this article is also provided at the end of the summary.

High level results presented concluded that:

- Four FEED studies opted for steam extraction from the base plant, while four FEED studies opted steam generation with an auxiliary boiler. One FEED study did not require steam (MTR membrane process).
- Steam extraction reduces steam cycle condenser duty and frees up cooling water for capture unit.
- Hybrid cooling systems to achieve comparable temperatures to cooling tower systems was indicated to be cost prohibitive. Hybrid systems also require substantial footprint. The University of Texas FEED study found dry air cooling to be 12.9% of total capital cost.
- The EPRI FEED study found opting for steam extraction to eliminate aux boilers and wet surface air cooling (WSAC) units would reduce balance of plant (BOP) cost 13-16%.

Data gaps that existed regarding host plant integration included factors such as the uncertainty around the impact of steam extraction on host system reliability and performance; the uncertainty around stack tie-in, concerns about pulling a vacuum in the flue gas duct or impacting backpressure at the heat recovery steam generator (HRSG); the uncertainty regarding solvent reclamation requirements and uncertainties regarding air emissions. Most of the FEED studies did not consider ancillary air emissions associated with the capture process. The host plant operational mode and capacity factor significantly impact business case with higher capacity factors producing better economic scenarios. Other cost factor includes the utilisation of modularisation and/or limitations of the site on constructability. This can impact number of capture trains due to the physical equipment size, technology risk reduction, turndown accommodation. Less accessible sites chose modularised units for shipping.

A quantitative analysis methodology was also presented to compare results from the FEED studies to NETL Fossil Energy baseline studies. It was noted that direct cost comparison is inadvisable since FEED costs were developed during a period of high-cost variability (2020-22), the costs were not developed on similar basis with same definitions and assumptions, and costs were impacted by inextricable factors like sparing philosophy, local labour rates, geotechnical, ambient conditions, etc. Results indicated that NETL models estimate performance derating reasonably well – deviations beyond 20% can be reasonably explained. While NETL models do not estimate O&M costs well, they provide sufficient granularity to pinpoint the source of the deviations and highlight the causes of O&M variability across projects.

Presentation 2

Commercial-scale FEED Study for MTR's Membrane CO_2 Capture Process

The FEED study results, presented by Brice Freeman were from a DOE project with total project cost of $6.4 million. The host site for the FEED study was the Wyoming ITC, located at the 405 MWe Dry Fork Station, fired using Powder River Basin sub-bituminous coal. The project utilises membranes to permeate CO_2 from flue gas using partial vacuum. Two membrane stages are incorporated to produce an 85% pure CO_2 product which is then liquefied to remove O_2.

Key aspects of the large pilot design are based upon the power plant site requirements: no new water withdrawals, zero liquid discharge, no new restrictions on operability, simple and fast interconnection with the existing plant system, and with the capture plant confined to < 4-acre plot space. The designed capture rate was 70%.

Learnings from the pilot design and construction phases include that identifying the most suitable process equipment for each service begins with process simulations, is refined through input from original equipment manufacturers (OEMs), and is confirmed once an engineering, procurement, and construction (EPC) contractor provides their detailed design input.

The large pilot utilises a 2-stage Polaris™ capture system: two trains (2x50%), each with capture rate of 70%. A techno-economic analysis of fitting the entire base plant with CO_2 capture was performed. The total project cost was estimated at $1.338 billion (2022$) with a total direct cost of $760 million. Operating cost dominated by power consumption (three-quarters of which is for operating the compressors and fans). When utilising a 90% capacity factor a total of 2.35 Mtpa CO_2 would be captured resulting in a capture cost of $57/tonne CO_2.

Brice Freeman, MTR Carbon Capture

Discussion Notes

When reviewing and completing techno-economic analysis (TEA), a key observation is to check on the size of large equipment designs to ensure that they are constructable since several FEED studies have converged on smaller equipment with multiple parallel trains.

A note was provided that, for a co-operative, the expected cost of capital is approximately 6%, whereas for a commercial project backed by private equity it is likely closer to 12%.

The MTR CO_2 capture process uses electricity from the power plant where it's installed to run its operations, so-called parasitic load. Instead of valuing that electricity based on what it could have earned in the market (i.e., the opportunity cost), the MTR process assigns a cost to that electricity based on the actual cost to the plant to generate it. The MTR process can run as a single stage, but more than one stage is required to approach the design capture rate. For membrane systems, costs rise more sharply as capture rates increase. The process is sensitive to partial pressure of CO_2 in flue gas, and since the host plant is at elevation, the 12% CO_2 partial pressure would be equivalent to 10% at sea level. The upper limit of capture rate for membrane systems is 90-95% for applications like cement and coal. While higher rates are technically possible, disproportionately higher costs are incurred, making them uneconomic in most cases.

Journal article: https://doi.org/10.1016/j.ijggc.2024.104268

FEED studies awarded under US DOE Funding Opportunity Announcement (FOA 2058):

- Bechtel: https://www.osti.gov/biblio/1836563
- Enchant: https://www.osti.gov/biblio/1889997
- EPRI: https://www.osti.gov/biblio/1867616
- ION Clean Energy: https://www.osti.gov/biblio/1963720
- Minnkota: https://www.osti.gov/biblio/1987837
- MTR Carbon Capture: https://www.osti.gov/biblio/1897679
- Southern Company: https://www.osti.gov/biblio/1890156
- University of Illinois Urbana-Champaign: https://www.osti.gov/biblio/1879443
- University of Texas: https://www.osti.gov/biblio/1878608

Session 2: CO_2 Transport Costs

Co-Chairs:
Machteld van den Broek (TU Delft); Keith Burnard (IEAGHG)

Speakers:
Colin Laing, Xodus; Andrew Bean, EPRI

The costs associated with the critical transport component of the CCS value chain are frequently underestimated in studies. Reliable cost estimates remain challenging to obtain, and data from real projects often reveal significantly higher costs than initial projections. This session sought to shed light on existing cost data, explore their limitations, and identify opportunities for improvement, with the aim of deepening understanding of CO_2 transport costs across different modes and supporting more accurate future estimations.

Presentation 1

CO_2 Transport Costs

Colin Laing, Xodus, opened the session by presenting Xodus' involvement in high-profile CCS initiatives, including Porthos and Aramis (Netherlands), Chevron's Gorgon CCS project (Australia), a trans-border CO_2 transport study (Europe), and the Northern Endurance Partnership (UK). In these projects, he recognised the difficulty in producing reliable cost estimates for pipeline infrastructure. Using the example of the natural gas pipeline infrastructure development in the UK, he explained that significant deviations often occur between initial projections and final, actual costs. It is easier to estimate costs for low-pressure pipelines (30 mbar to 7 barg) as the work volumes are high (ca. £800 million annually), they are usually placed along pre-approved existing routes, and data (costs) are drawn from multiple operators and contractors. Prices are accepted up to five years in advance. In contrast, it is difficult to estimate costs for high-pressure steel pipelines (80-100 barg) with low volumes (£80 to £100 million annually), often built on new routes with previously unknown location-specific challenges, and data is available from only one single monopoly operator. The budget is only accepted no more than one year in advance.

Laing emphasised the importance of the gated process in the development of an infrastructure project. This gated process aims to balance the pre-project cost required to get reliable cost estimates with the risk that costs are highly under- or overestimated. The five phases of the gated process include a project brief, strategic outline case (SOC), outline business case, full business case (FBC), and the project completion. With a SOC, cost estimates can still differ by -50% to +100% from the real costs, but this accuracy improves after each phase. The pre-project costs up to FBC (or FID) can be as high as 10% of total installed cost of the whole project.

He argued that it may seem that costs associated with critical CO_2 transport infrastructure are frequently underestimated. However, they still usually fall in the expected accuracy ranges of the gated process, especially as these projects are unique and heavily influenced by local conditions. For projects to transport CO_2 by ship, similar difficulties emerge to estimate costs due to similar issues including location-specific factors. Better communication with stakeholders is essential to manage expectations, and to convey the uncertainties in the early cost estimates.

Colin Laing (right), Xodus

Laing also touched on the current limitations in publicly available transport and storage cost data. Much of the available information (ranging between \$15 to \$125 per tonne CO_2 for transport and storage (T&S)) is tied to government-backed projects, and the full life-cycle costs of CCS operations remain unclear due to the diversity of global project types.

Presentation 2

US Eastern Seaboard Transport and Storage Study: Summary of CO_2 Transport Costs

EPRI's Andrew Bean provided a comprehensive overview of a transport and storage study for the U.S. Eastern Seaboard. The study sought to understand how CCS infrastructure could support decarbonisation across the region. Using four integrated models, including CO2NCORD and SCO2TPRO, the team analysed seventeen CCS deployment scenarios. The CO2NCORD model helped classify emission sources and filter out facilities that do not qualify for the 45Q tax credit (a credit awarded for each tonne of CO_2 stored permanently underground). Next, storage options were identified based on reservoir characteristics like temperature gradients, rock permeability and structural elements. However, due to a lack of drilling and monitoring wells, the availability of high-quality data was limited, especially for offshore sites.

For transport infrastructure, the geospatial tool called CostMapPro was used to model cost-effective pipeline routes considering existing infrastructure and geographic barriers. Routes along existing corridors like pipelines and roads were preferred while costly features like rivers and railways were avoided. Complementing this, the NETL Pipeline Cost Tool was used to calculate CAPEX and OPEX based on flow rate, length, elevation, and other parameters. In a final integration step, using SimCCSPro, the most cost-effective CO_2 transport paths were selected for all scenarios.

Andrew Bean, EPRI

The transport cost estimates across scenarios ranged from \$8 to \$20 per tonne of CO_2 (and T&S costs between -\$70 in case of EOR and \$40). Offshore scenarios consistently showed the highest transport and storage costs compared to onshore scenarios, particularly when combined with barging. In many of the scenarios common CO_2 trunklines emerged. The study found that transport costs generally declined as the number of candidate storage areas increased, allowing for more flexible and cost-optimised routing.

Discussion Notes

During the discussion of this session, several key issues were raised. There was a general consensus that the development of a full CO_2 pipeline network as presented by Bean still remains distant. This was because it requires coordination between multiple emitters and storage facilities, which was described as difficult with respect to logistics, organisation, permitting difficulties, public opposition and local geological conditions that introduce conflicting requirements. Effective communication with communities and transparency in planning were highlighted as essential to building public trust.

In response to questions about cost model assumptions, Bean clarified that most models are designed with historic onshore transport in mind and often lack the precision needed for offshore operations. Often these are an order of magnitude lower than the T&S costs of real projects presented by Laing. Another point of interest was the exclusion of CO_2 purity considerations—such as dehydration or reducing oxygen content—from most transport models, as these are typically determined by specific project requirements.

The session concluded with a brief discussion covering alternative transport modes. Barging was shown to be cost-effective in certain localised cases, but not universally. Other modes like rail and truck were not thoroughly assessed in this study. A final question addressed the reuse of offshore pipelines in the UK. Laing responded that refurbishing such infrastructure is extremely expensive, with some efforts costing up to £300 million just to excavate and restore old pipelines. The timeline for such refurbishments is highly variable and project specific.

Overall, the session underscored the need for more transparent and comprehensive cost data to inform strategic investment in CO_2 transport infrastructure.

Session 3: Realistic Financing Assumptions

Co-chairs:
Mathilde Fajardy, IEA; Sean McCoy, University of Calgary

Speakers:
Jeff Brown, Stanford University and Energy Futures Initiative; Alexander Shelby, Barclays

The cost of financing capital intensive projects such as power and industrial facilities with CCS has a major impact on their economic viability. Moreover, the addition of technologies such as CCS that have a higher perceived risk can increase their cost of capital. As a result, governments have introduced policies that can offset the capital cost through tax credits or reduce the downside risk from price volatility. This session examined the factors that influence the cost of financing for CCS through presentations from Jeff Brown of Stanford University and Alexander Shelby of Barclays and a moderated discussion.

Presentation 1

Finance Costs Drive CCS Cost: What Factors Drive Finance Costs?

Jeff Brown emphasised that financing costs are a major driver of overall CCS expenses, often accounting for up to 50% of the total cost per tonne of CO_2 captured and stored. He highlighted that inflation, rising interest rates, and retrofit challenges have significantly eroded the benefits of the U.S. 45Q tax credit, making many CCS projects financially unviable without additional support. For example, a CCS project in 2024 might have a levelised cost of CO_2 capture that is two-thirds higher than a comparable project pre-COVID.

Jeff Brown, Stanford University and Energy Futures Initiative

Brown noted that the industrial sector has limited operational deployment experience with CCS, with notable exceptions in gas processing and steam methane reforming. He highlighted the persistent lack of transparent, high-quality data on capital and operating expenditures, financing structures, and project performance, which hinders robust techno-economic analysis and cross-sector cost benchmarking. To address these constraints, Brown advocated for targeted industrial policy interventions, enhanced fiscal incentives, and streamlined regulatory frameworks to reduce investment risk and facilitate large-scale CCS deployment – particularly in hard-to-abate sectors. Specific recommendations included increasing the 45Q tax credit value to fully offset capture and storage costs for industrial point sources and accelerating the approval process for Class VI wells.

Presentation 2

Insights from Barclays

Alexander Shelby elaborated on the financial structuring of CCS projects, introducing the concept of the "green premium" – the additional cost associated with decarbonised products or services relative to their higher-emission counterparts – which is often necessary to make CCS investments economically viable. He emphasised the need to tailor financial models to the specifics of each project, taking into account variables such as geographic location, contract structures and public perception.

Alexander Shelby (left), Barclays

Shelby noted that many CCS projects currently rely on growth equity, as they often lack long-term offtake agreements that would otherwise provide revenue certainty. In the absence of such agreements, growth equity or structured equity investors – who typically demand higher returns than traditional infrastructure investors – are more likely to participate in early-stage financing. He further explained that the cost of capital is dynamic, evolving over the project lifecycle in response to changes in risk exposure and financing arrangements. As projects demonstrate operational reliability, they generally gain access to more favourable financing terms and reduced capital costs.

Shelby also highlighted a potential emerging market dynamic: data centres may play a role in subsidising CCS deployment by paying a premium for access to reliable, low-carbon power, thus creating new revenue opportunities for CCS-integrated energy projects.

Discussion Notes

The discussion covered a wide range of topics. It was pointed out that there is a disconnect between the use of the Consumer Price Index (CPI) to adjust the 45Q credit and escalation in the cost of industrial equipment. Subsequent discussion touched on the role of "green finance" and insurance companies, the conservative stance of banks toward technology risk, and the critical risk of public perception—particularly for transport and storage—when it comes to financing CCS. The final topic of discussion was how technological risk and, thus, finance costs could best and most rapidly be reduced. It was suggested that standardisation and repetition in capture technologies, especially for gas boilers and natural gas combined cycle plants, could lead to a reduction in the cost of capture more rapidly than fundamental improvements in technology (e.g., reduced energy separation). There was a sense that government could play a role in driving projects to standardise and de-risk projects.

Session 4: Basis for CCUS Costs Internationally

Co-chairs:
Mathilde Fajardy, IEA; Sean McCoy, University of Calgary

Speakers:
Shannon Timmons, International CCS Knowledge Centre; Geoff Bongers, Gamma Energy Technology

Most operating CCUS projects to date are in North America. As first-of-a-kind projects fire up in Asia and Europe, there is still little evidence as to how CCUS costs vary across regions, depending on country-specific variables that might include labour, energy, materials, and financing costs, as well as access to and cost of transport and storage infrastructure. This session discussed results from FEED studies in Canada as well as the challenges to translate FEED studies results to other regions for cost modelling purposes, with examples from Australia and Japan.

Presentation 1

CCS Costs: Key Learnings from Emissions Reductions Alberta's Carbon Capture Kickstart (CCK) Programme

Shannon Timmons provided insights from the Carbon Capture Kickstart (CCK) programme in Canada. The programme was launched in 2022 by Emissions Reduction Alberta (ERA) to accelerate carbon capture deployment in Alberta, with support from Natural Resources Canada (NRCan). The initiative supported eleven FEED studies across 27 facilities across applications, including electricity, oil & gas, fertiliser, and cement. All combined, these projects have the potential to deliver up to 24 Mtonnes in annual CO_2 reductions by 2030—about 10% of Alberta's current greenhouse gas emissions. Because of the 2030 commissioning deadline required by the programme, most FEED studies focused on off-the-shelf chemical absorption amine-based capture technologies. Designs were also optimised to minimise CAPEX, thereby maximise support from Canada's CCS investment tax credit.

Given the confidential nature of the FEED studies, the results were anonymised when provided to the CCS Knowledge Centre. To harmonise results from the different FEEDS, Shannon and colleagues developed a standardised calculator to compare projects using Levelised Cost of Capture (LCOC) and Levelised Cost of Avoidance (LCOA). They adopted the U.S. DOE NETL cost estimation method, with assumptions including a 8% discount rate, 25-year operating period, and inflation-adjusted capital and O&M costs. Analysis revealed that the LCOC varied widely across projects, ranging from CAN$104 to CAN$256 per tonne CO_2.

Numerous strategies for cost reduction were explored by companies and discussed. This included optimising flue gas treatment, improving system redundancy, and assessing utility configurations (e.g., electric vs steam compression, air vs water cooling). Modularisation and flue gas recirculation were also considered.

Shannon Timmons, International CCS Knowledge Centre

Presentation 2

Costing CCS for a Modelling Study

The first part of the presentation by Geoff Bongers focused on the limitations of translating cost data from FEED studies across regions. While high-quality FEED studies provide valuable insights, their region-specific inputs – such as labour productivity, crew rates, and material costs – make it challenging to generalise results. The analysis leaned on models from the Australian Power Generation Technology report (2015) and incorporated capital cost estimates from GenCost (Australia) and Lazard (Japan) but noted that publicly available data often lacks the granularity needed for precise comparisons.

In the second part of his presentation, the discussion shifted to the role of low-emissions dispatchable power within a least-cost net-zero framework. The MEGS (Modelling of Energy and Grid Services) model was used to simulate power system costs across different decarbonisation scenarios. It was acknowledged that renewables like wind, solar, and existing hydro remain the cheapest power sources, while dispatchable power with CCS struggles to compete on price. However, simulations revealed that some form of CCS particularly bioenergy with CCS (BECCS) is necessary to achieve net-zero emissions affordably. The analysis highlighted systemic challenges such as Australia's coal dependency and weak regional interconnections, which also mirror Japan's fragmented power grid. The presentation concluded that achieving net-zero without CCS technologies leads to prohibitively high system costs, reinforcing the need to consider CCS, especially BECCS, as part of the energy mix.

Geoff Bongers, Gamma Energy Technology

Discussion Notes

Following Timmons' presentation, participants raised the challenge of working with anonymised results from the CCK programme, which contributed to high variability in cost estimates and did not allow for cost comparisons between sectors. Participants also touched on differences between Canadian and NETL FEED reports, emphasising site-specific factors like climate and productivity that influence outcomes. The updated NETL report[2] with improved assumptions for capture rates (95%+) was mentioned as more suitable for retrofit scenarios compared to older baseline data often cited in studies. Participants also discussed the impact of value engineering on decreasing costs. Results showed that value engineering did not uncover common cost-saving strategies across projects, suggesting that optimisation may need to be tailored on a site-by-site basis.

Discussion following Bongers' presentation delved into nuanced questions surrounding the feasibility, scope, and economic modelling of carbon capture technologies, particularly BECCS. Participants raised concerns about constraints on biomass availability, noting that assumptions in the modelling only allowed for limited BECCS deployment – roughly equivalent to one Drax-sized unit per state in Australia (totalling about 6 GW). The sustainability and practicality of large-scale BECCS remain controversial due to questions about biomass supply and land-use implications. Additionally, BECCS on biofuels was not a primary focus, especially given Australia's strategy to reserve biomass use mainly for aviation and pursue electrification elsewhere.

[2] T. Schmitt, S. Leptinsky, M. Turner, A. Zoelle, C. White, S. Hughes, S. Homsy, T. Shultz, and R. James, "Fossil Energy Baseline Revision 4a," National Energy Technology Laboratory, Pittsburgh, October 14, 2022.

Session 5: Storage Costs Reduction

Co-chairs:
Jon Gibbins, UKCCSRC

Speakers:
Candice Paton, Enhance Energy; Wes Peck, EERC; Ole Engels, Heidelberg Materials

This session focused on the cost of the storage component in CCS and the potential for future cost reductions. It included three presentations followed by a general discussion. Key points are summarised below, with the overall takeaway that, although storage represents a relatively small portion of the total CCUS system cost, its timely availability in the required capacity is critical. Therefore, it is in the interest of both T&S operators and CO_2 capture developers to collaborate early – sharing both the upfront costs of developing storage and the risks associated with cost uncertainties. These uncertainties are unlikely to be resolved until a storage project has been built and operated over a sustained period.

Presentation 1

The 'S' in CCUS: Cost Drivers for Onshore CO_2 Storage

Candice Paton from Enhance Energy gave a presentation based on experience with the Alberta Carbon Trunk Line Project. Enhance is currently sequestering 1.5 Mtpa into EOR with permanent storage, with over 7 Mt cumulatively stored. In Alberta, compliance credits can be generated when permanent containment is demonstrated in EOR reservoirs, with no CO_2 removal permitted from the zone into which it was injected.

The importance of engaging with indigenous communities in the areas where Enhanced Energy operates was emphasised. Enhance Energy is committed to economic reconciliation and investment in these communities, and the storage of CO_2 should provide further economic stability.

While clients will, understandably, want to know up front "How much will it cost to store CO_2 in our project?" there is no simple answer, given that many factors that can significantly affect the price are not known at the early stages in project development. Yet, at the same time, capture plant clients need an idea of T&S costs to achieve FID.

These important, but initially uncertain, factors include:

- Considerations related to CO_2 storage and capacity, with it being very important to understand the limitations and assumptions made in the evaluation process. There is a critical need for accurate initial data to avoid project failures; incorrect assumptions may significantly impact a project's viability

- Pore space ownership and other aspects of the local legislative framework and the impact on project costs of achieving compliance need strategic planning up front (pore space is owned by the Crown in Alberta so having a single owner facilitated a competitive hub).

Candice Paton, Enhance Energy

The BIG 4 questions that need to be answered about a proposed storage reservoir are:

- Containment
- Capacity
    - Assumptions made before drilling involve dealing with uncertainties and complexity but may greatly impact costs. E.g. will the assumptions made for the first 3 wells hold for the next ones? Will money need to be spent on drilling new wells because pore space differs from assumptions, significantly impacting capacity?
    - Mapping needs to be done to understand the region of jurisdiction.
    - What are the charges for the use of pore space. For example, Alberta is putting royalty on pore space – how does this charge cost translate to an overall costs.
- Injectivity: A chart was presented showing 8 vs 15% porosity and permeability varying by factors of 100 for 2 wells that are in close proximity.
- Induced seismicity: requirements for monitoring need to be adjusted based on the potential for local impacts and local regulatory requirements - variations in these can significantly affect the cost.

Obviously, storage providers need to rely on the credits received for storage to make up for the costs, but what the cost of these credits are depends on the risk premium that has to be included and this in turn is strongly affected by how risk and liability are shared between emitters and storage providers. Clear agreements and a shared understanding of the risks involved in CO_2 storage projects are essential; working with partners who have done this before is likely to be helpful.

There is more reliability on construction and operating costs for the pipeline elements of a T&S system then for the sequestration elements, but these can still escalate quickly during project development. Over a full T&S project lifetime, as new sources start to inject more uncertainty is generated and in the longer-term capacity at any given time is not known for certain.

Presentation 2

Cost of Drilling in North Dakota

On the cost of drilling for CCUS in North Dakota, Wes Peck emphasised the importance of understanding the cost drivers and the potential for cost savings through strategic planning around the most significant cost drivers for a CCUS well:

- Site preparation: site selection, landowner agreements (with very variable costs), site surveys, building the site (pad and roadway for access)
- Mobilisation - moving a rig can cost millions of dollars (distance, number of loads, time of year – e.g. in winter there may be heavy snows, and equipment needs to be heated to avoid low temperature embrittlement)
- Long-lead-time items - casing, wellhead, auxiliary gauges, cement
- General cost of drilling – number of days and daily operating cost, general drilling contractor, rig, drilling fluid, rentals of equipment
- Characterisation of the subsurface - assumptions can't give you a permit, there needs to be coring, logging and formation testing

Potential strategies for cost savings therefore include optimising the site preparation process and carefully planning the procurement of long lead items.

Wes Peck – EERC

The impact of the following major cost drivers was discussed:

1. One formation vs multiple formations of interest
2. Depth
3. Stratigraphic test well with intent to transition to a Class VI injection/monitoring well vs plug and abandonment of a stratigraphic test well
4. Completion Cost – initial ambiguities that become knowns at the end will impact the resulting cost for better or worse

Examples were shared of how regulatory and weather challenges were managed in previous projects. It was also noted that the need for additional activities, such as corrosion studies, can impact project timelines and costs.

Presentation 3

Levelised Cost of CO_2 Storage

Ole Engels presented on the levelised cost of CO_2 storage based on Heidelberg Materials' experience of CCUS for cement production, particularly regarding the Mitchell, Indiana, project, which has been allocated $500 M US DOE funding for capture and T&S. They shot 3D seismic last year and identified possible horizons and currently have drilled a 3500 foot well into the Potosi formation which is offset from the Wabash well.

There is a significant difference between onshore and offshore storage, offshore storage typically has a higher cost premium (4x) but there is a significant risk factor from the environmental and social aspects for onshore storage. Nonetheless, there are obviously major opportunities to reduce T&S costs by going from offshore to onshore and also by reducing the cost of required monitoring activities.

Thorough injectivity assessments are required, storage sites with high injectivity and large storage capacity obviously offer significant economic benefits. It was stated that none of the storage sites operating today didn't struggle with injectivity so the availability of maps of reservoir thickness vs permeability vs injectivity is important to help determine viable storage options. Storage depth and the availability of multiple horizons are also important factors.

Discussion Notes

It was noted that while investors want guarantees on prices this is not feasible. For example, there is no guarantee on the future price of commodities like steel although pore space tends to be a firmer price. Costs and lead times for drilling operations are also affected by competition from the oil and gas industry.

Unless you have T&S, you can't get to FID on capture projects so how do we as an industry make the financers confident enough, but the storage industry gives a number/cost that is fair and equitable? The suggestion was to develop storage first and have wells ready and 'waiting' for CO_2. Emitters should come together with storage providers to assess the geology (i.e. spend money together to facilitate projects moving forward). Having enough investigation on the geology, and proper routing plans, will accelerate permitting the well, and therefore the uncertainty on the storage gets erased. It is important to work with storage experts that have experience in the location you are investigating, since location plays a major role in costs.

To support the idea of the 'storage first' approach, the onshore development and exploration costs for an onshore storage site were stated to be in the range $60-70M, with 6/7 M $ per well, compared to pipeline and capture costs in the billions. Given timing to FID becomes critical, especially due to permits which can take six to eight months, it is reasonable to spend extra millions of dollars on storage to lessen the hardships of getting to overall FID.

Breakout Sessions

Breakout 1: International CCS Drivers

Chair:
Machteld van den Broek, TU Delft

Moderator:
Hugh Barlow, GCCSI

Hugh Barlow started with an overview of the drivers for CCS, which are government interventions to realise its economic value compared to freely emitting CO_2 technologies. The drivers can be subdivided into four groups, each with its own advantages and disadvantages:

1. carbon taxes,
2. carbon markets,
3. subsidies & grants, and
4. regulatory mandates.

Different world regions have adopted various tools. The USA and Canada lean towards the third group with implementing tax credits and loan guarantees (3), and at state level also carbon markets (2) play a role. Canada offers tax credits and grants (3) alongside carbon markets (2), Europe relies on the EU ETS (2), innovation funding, and direct investments (3), while Asia-Pacific countries implement carbon markets (2), taxes (1), and grants (3) with the involvement of state-owned enterprises. CCS deployment is progressing slowly, challenges remain, and questions persist about how best to ensure long-term certainty and the private sector's role in driving CCS forward.

During the discussion, participants emphasised the critical role of government intervention and long-term political alignment in incentivising CCS. Strong leadership and consistent policies were highlighted as essential, with examples from China, Japan, and the Middle East demonstrating how stable political commitment can support CCS initiatives. While political alignment is feasible in democratic nations, it seems more difficult to sustain due to shifting political landscapes.

The discussion also addressed the economic implications of decarbonisation, particularly who will absorb the increased costs of products influenced by these initiatives. It was noted that while material costs may rise, the overall price increase for end-products may be proportionally lower—such as the relatively small impact of green cement prices on the total cost of infrastructure projects like bridges. On the other hand, a strong climate policy would affect all components of building a bridge, not only cement, and therefore still result in an overall high price increase. In this context, also generational differences were explored, with observations that younger generations may place a higher intrinsic value on low-carbon options and be more willing to sacrifice convenience and comfort for environmental benefits.

Japan, UK, and Canada Japan, the UK, and Canada appear to offer supportive environments for CCS deployment. Japan was presented as a strong example of long-term alignment, with contracts between the government and companies ensuring consistent decarbonisation efforts over time. In the UK, the cluster system has driven funding and progress, though it now faces pressure from competing budget priorities, again highlighting the need for sustained political commitment. Canada also demonstrates strong support for CCS, but regulatory hurdles remain, particularly in Alberta, where requirements that CCS sites be located within specific gas fields could eliminate some otherwise cost-effective options. Meanwhile, Southeast Asia was identified as being in the early stages of establishing the regulatory and policy frameworks needed to drive CCS development.

Hugh Barlow, GCCSI. Breakout 1

Overall, the session concluded that current CCS deployment remains insufficient to meet climate targets. Continued and consistent government support and intervention were deemed essential for scaling CCS deployment.

Breakout 2: Moving towards 100% Capture – Is it Possible and is it Worth it?

Chair:
Jon Gibbins, UKCCSRC

Moderator:
Jon Gibbins, UKCCSRC

Speakers:
Ryan Cownden, University of Sheffield; Simon Roussanaly, SINTEF Energy

The breakout discussed whether capture of 100% of the added CO_2 in a flue gas stream from a capture plant was both feasible and worthwhile. Note that 100% capture (of the fuel-derived CO_2) is technically feasible, with the only CO_2 emitted being that contained in the incoming combustion air.

Jon Gibbins began by looking at the legal challenge to the Net Zero Teesside (NZT) gas turbine power project being built in a large industrial area previously occupied by a large steel plant in the northeast of England, tied into a cluster of pipelines going offshore. In February 2024, the government granted permission for this scheme, recognising that it would help the UK reach its goal of net zero, targeted by 2050, but the plant was the subject of a legal challenge – details of which were provided in the presentation. The NZT developers stated that they expect 90% of the direct CO_2 emissions produced by the gas turbine to be captured over the plant's lifetime. Of the 10% not captured, two thirds were due to the CO_2 capture system not running because the CO_2 transportation and storage system is unavailable and one third is residual emissions while the CO_2 capture system is running. This implies an average capture rate while the capture plant is operating of ~96.5%. The theory behind a method to control a PCC plant to deliver high capture rates at low specific reboiler duties was also described, with an example of its use on a pilot plant in China.

Jon Gibbins, Breakout 2

Next, Ryan Cownden from the University of Sheffield presented on pilot-scale high capture demonstrations, life cycle emissions of NGCC plants with CCS, and high capture cost studies. Note that all capture rates quoted in this section refer to gross capture (i.e., the fraction of all the CO_2 in the incoming flue gas).

Examples of high-capture pilot tests included:

1. NCCC – National Carbon Capture Centre:
   a) High capture with piperazine (PZ) in 2018. Coal-fired plant flue gas up to 99% gross capture. Going from 90 to 99% increased specific reboiler duty (SRD) by < 5%;
   b) Same facility in 2019, with simulated NGCC flue gas. Up to 96% gross capture with PZ and lean/rich loadings similar to the coal flue gas tests.
2. TCM – Technology Centre Mongstad with NGCC flue gas:
   a) In 2018, up to 98% gross capture with 34-38%wt monoethanolamine (MEA) and SRD as low as 3.8 GJ/t CO_2;
   b) In 2019, up to 98% gross capture with CESAR-1 and variable absorber bed lengths (12-24 m). Going from 90-99% capture led to 7-10% increase in SRD;
   c) In 2020, 98% gross capture with CESAR-1, with SRD values from 3.4-3.9 GJ/t CO_2 during a 7-day steady state test.
3. RWE Niederaussem coal plant, 2023/2024:
   a) Ran two tests of two months duration each with CESAR-1. Went up to 99.8% capture;
   b) Increasing the number of absorber beds from 3 to 4 decreased the SRD;
   c) Running the desorber at higher temperatures and pressures also helped lower the SRD;
   d) At 99% gross capture, the SRD was 3.3-3.9 GJ/t CO_2 at high desorber pressure with 4 absorber beds.

On NGCC life cycle emissions, from wellhead to electricity, increased capture rates give incremental reductions in overall emissions rates, but at high CO_2 capture rates (>95%) most life cycle emissions rate are from the natural gas supply chain. Existing technologies and low emission natural gas production practices that have been demonstrated at industrial scale could reduce life cycle emission intensity to 22 kg CO_2e/MWh from 111 kg CO_2e/MWh with global average NG supply and 98.5% CO_2 capture. This would make the emission intensity of NGCC with CCS slightly higher than wind turbines and considerably lower than photovoltaic power.

Looking at costs, the estimated increase in the cost of electricity due to increasing the capture rate from 90-99% had a small impact compared to other factors. However, there were some caveats: long term testing (12+ months continuous) would be needed to verify capture performance, plus demonstration/design of high capture over full life cycle.

When considering the value, topics to consider would be:

- From whose perspective?
- Compared to what alternative?
- What is the value?

With a tax break, the marginal cost would be much less than the reward. The cost of capture would be less at mid-90% capture than at 90%.

Finally, SINTEF Energy's Simon Roussanaly spoke on the topic of '100% capture of fossil CO_2, should we do it?'

The expectation was for the European power system in 2050 to achieve a 99% reduction in emissions compared to 1990 levels. Fossil power with CCS would be expected to provide c. 2000 TWh of electricity in Europe in 2050 (c. 25% of total electricity generation). Large shares of generation from coal power and biomass co-firing were expected with a smaller share from natural gas. Results were also presented from a study investigating the effect of CCS on the cost of life cycle emissions of various end products. The study showed that large reductions in life cycle emissions were possible with very minimal impact on cost for most end products, except for air travel.

Discussion following the presentations was based on questions from the breakout participants.

1. What are plans to bring down costs?

   In reality, there would always be cost reduction curves, due to both continuous improvement and innovation. Learning while building would be important. In aiming at the megatonne and moving towards the gigatonne scale, large scale facilities would need to be built. Research would need to be adequately resourced. With current projects, the first half of them had outcomes that were hugely different from the second half, solely because of the continuous R&D that went into improving methods and technology.

2. How practical was it to sustain high CO_2 capture rates in real life operations involving solvent management?

   This goes back to the need for long duration testing to demonstrate improving strategies and management for these applications. Grid stability would also need to be considered, with the ability to pause solvent regeneration for a brief period of time.

3. In terms of systems, would it be cheaper to go to 95% than to 90% capture?

   Once 100% capture is the target, it becomes a challenge. The effort to reach 100% is so difficult that the opportunity for 95% capture might be missed. So, in order not to miss opportunities, would it be better to focus on 90 to 95% rather than on 100%?

   The fairest way to set capture rates would be to say that everything will be net zero, possibly, not considering costs. There is then constant innovation. When looking at biomass for BECCS, for example, there are issues but, at the end of the day, if we are looking at 90-95%, a lot of biomass does not have to be used to reach the end goals.

Overall, attendees at the session expressed optimism about achieving carbon capture rates of ≥95% with minimal impact on overall project economics. However, there was greater uncertainty regarding the feasibility and cost-effectiveness of achieving near-100% capture. As capture efficiencies approach such high levels, it becomes increasingly important to clearly define the basis for reported capture rates. Specifically, it is critical to distinguish between gross capture efficiency – based on total CO_2 in the flue gas – and net or fuel-derived CO_2 capture, which accounts only for the CO_2 generated from fuel combustion and excludes ambient CO_2 present in combustion air. This distinction has significant implications for technology benchmarking, performance claims, and regulatory compliance.

Breakout 3: Impact of Plant Integration

Chair:
Abhoyjit Bown, EPRI

Moderator:
Abhoyjit Bhown, EPRI

With a focus on the impact of plant integration on CCS technologies, two primary studies were discussed:

1. Power Plant Integration (EPRI, 2022) and
2. Environmental Considerations (EPRI, 2024).

These studies explore various aspects of CCS implementation, including air quality, water usage, land requirements, and public engagement.

The breakout aimed to address the challenges and opportunities associated with integrating CCS into existing power plants. By examining different regeneration options and their implications, insights into optimising CCS processes for better efficiency, cost-effectiveness, and environmental impact were provided.

Abhoyjit Bown, EPRI

Power Plant Integration

The integration of CCS into power plants involves several regeneration options to provide the necessary thermal energy for the capture process. The three main options are steam extraction, standalone combined heat and power (CHP), and standalone boiler systems. Each option has distinct advantages and disadvantages.

Steam Extraction

This method is the most efficient and potentially the least costly option, but it is also the least flexible. It involves extracting steam from the power plant's intermediate and low-pressure crossover, which impacts turbine operation and performance.

Standalone CHP

CHP systems are efficient and produce extra electricity, offering flexibility but at a higher cost. CHP systems are more expensive due to the need for additional equipment such as turbines and heat recovery steam generators (HRSG). Despite the higher cost, CHP systems provide greater operational flexibility and can be started separately from the main power plant, reducing start-up times.

Standalone Boiler Systems

Boilers, while the least efficient, do not cause a derate on the power plant and offer the most flexibility. They are typically used in demonstration units for their simplicity and minimal power plant modifications. Boilers have the lowest efficiency and highest water consumption among the three options. They are also the least costly in terms of capital expenditure compared to CHP systems.

The session also examined four base plants: DOE baselines for coal and NGCC, Peterhead, and Petra Nova. Key performance metrics such as plant efficiency, parasitic energy, coefficient of performance, water withdrawal, capital cost, and flexibility were analysed to compare the different regeneration options.

Steam Requirements for CCS

A significant amount of steam is required by the reboiler, typically 2.5–3 GJ/t at 120–150°C. Modelling often favours steam extraction from the intermediate and low-pressure crossover for its high thermal efficiency, though it requires significant plant modifications and can reduce turbine performance. In contrast, demonstration units often use standalone steam generation for greater flexibility and simplicity, with minimal plant modifications and no derating.

Case Analysis

The session featured a comparative case analysis focused on base plant configurations for CCS integration. Four reference cases were examined:

- NETL coal-fired power plant (650 MWe)
- NETL NGCC plant (740 MWe)
- Peterhead NGCC plant (400 MWe)
- Petra Nova coal-fired plant (240 MWe with CCS retrofitted)

Each case was assessed using key performance indicators, including thermal efficiency, coefficient of performance (COP), water withdrawal, capital expenditure (CAPEX), operational flexibility, and land requirements.

Plant Efficiency

Combined heat and power (CHP) systems and steam extraction were identified as more efficient CO_2 capture energy supply methods compared to dedicated auxiliary boilers. However, both approaches impose efficiency penalties on the host power plant:

- Steam extraction reduces net plant efficiency by approximately 20% in coal-fired plants and 11–18% in NGCC plants, depending on site-specific conditions.
- CHP systems, by recovering and utilising waste heat, can increase net power output by up to 50% for coal plants and 10% for NGCC plants, making CHP the most efficiency-advantaged option for coal applications.

Coefficient of Performance (COP)

The coefficient of performance—defined as the ratio of thermal energy available for solvent regeneration to the additional energy input required to provide that heat—varied significantly across configurations:

- Steam extraction (NGCC): COP = ~2.0
- CHP systems: COP = ~1.1
- Auxiliary boilers: COP = ~0.85

These results suggest that steam extraction offers the highest thermal efficiency for solvent regeneration in NGCC plants, whereas boilers represent the least efficient option.

Water Withdrawal

Water withdrawal was significantly higher for coal plants compared to NGCC plants, with capture plants on coal-fired units approximately doubling water consumption. Coal plants use more water due to higher condenser duty and lower power efficiency. Capture plants also increase water consumption due to the cooling duty transferred from the power plant to the CCS plant.

Capital Expenditure

Steam extraction was potentially low cost but high risk, while standalone units were high cost but low risk. Steam extraction requires significant modifications to the power plant, including turbine modifications and steam routing, which can be costly and risky. Standalone units, such as CHP systems and boilers, have higher capital costs but lower risks due to their simplicity and minimal power plant modifications.

Operational Flexibility

Start-up times and operational independence were analysed to assess plant flexibility:

- Boilers demonstrated the shortest start-up times (~0.5 hours), offering rapid thermal delivery.
- CHP systems can operate independently from the main power plant and achieve start-up within ~1 hour.
- Steam extraction systems require full plant start-up, resulting in extended delays: ~6 hours for NGCC and up to 9 hours for coal-fired plants.

Standalone or decoupled thermal sources (e.g., CHP or boilers) provide superior operational flexibility compared to integrated steam extraction systems.

Environmental Considerations

The environmental considerations of CCS were evaluated to enable successful deployment. Air quality, water usage, land requirements, and public engagement were key areas of focus.

Air Quality

The dispersion model SCICHEM was selected for handling non-linear atmospheric chemistry. Simulations of emissions from coal and gas-fired power plants using different amines (MEA, PZ, AMP & PZ mix) were conducted. A case study on Piperazine (PZ) emissions and surface concentrations with and without acid wash highlighted the importance of fine-scale modelling to resolve higher concentrations near the source. Acid wash was found to reduce surface concentrations approximately an order of magnitude, indicating its effectiveness.

Water Usage

Thermally driven capture increases water consumption. Permitting, siting, and regulatory impacts were discussed, along with cooling water, intake, and discharge implications. Water and wastewater treatment needs were also addressed, emphasising the importance of alternative cooling approaches and water treatment for amine-rich wastewaters. New cooling systems may be required, and increased intake and discharge requirements could have aquatic impacts.

Land Use Requirement

The integration of CCS significantly increases site land requirements – potentially doubling the footprint of the base power plant. Key considerations include:

- Loss of existing property buffers and space constraints
- Land acquisition for CO_2 capture units, compression infrastructure and ancillary systems
- Introduction of new externalities, including noise, odour, and visual impacts

The substantial spatial footprint of CCS infrastructure underscores the importance of early-stage land planning and community impact assessments during project development.

Public Engagement

Effective public engagement is crucial for CCS deployment. Direct and transparent communication with the community, emphasising community-specific communication methods, training, and education, is essential. Maintaining an open line of communication for continuous dialogue helps address environmental justice concerns and ensures a smooth development process. The public is generally not aware that CCS has existed for a long time, making it important to find the best ways to engage and educate them.

Key Takeaways

Addressing environmental concerns is vital for ensuring a smooth development process and long-term benefits for all stakeholders. Public awareness of CCS is crucial for understanding CO_2 management and infrastructure use. Implementing CCS can offer job security for workers facing displacement due to plant closures, providing long-term benefits to the workforce by preserving jobs, maintaining wages, and eliminating the need for relocation.

The session highlighted the importance of considering various factors when integrating CCS into power plants. By evaluating different regeneration options and their implications, stakeholders can make informed decisions to optimise CCS processes for better efficiency, cost-effectiveness, and environmental impact. Future research priorities include alternative cooling approaches, water treatment for amine-rich wastewaters, and the impact of amines on aquatic life. Additionally, addressing public engagement and workforce development is crucial for the successful deployment of CCS at scale.

References

A. Berger. Comparing Methods of Supplying Thermal Energy for Regenerating Carbon Capture Solvents, EPRI Report 3002024314 (2022).

Environmental Concern for Carbon Capture Deployment, EPRI Report 3002030909 (2024).

Closing Plenary

Co-chairs:

Bill Elliot, Bechtel
Keith Burnard, IEAGHG

The closing session of the 8th CCS Cost Network Workshop provided an opportunity for participants to reflect on the discourse of the event and to support shape the agenda for the next workshops. The session was co-chaired by Bill Elliott (Bechtel) and Keith Burnard (IEAGHG).

Bill Elliott opened the session by expressing appreciation to all participants for their engagement. He invited attendees to suggest potential focus areas for the next workshop. Themes proposed included the following:

1. Cost to Society of CO_2 Emissions
2. Presentation of Actual Construction Costs
3. Real Costs of Projects and Cost Overruns
4. Transparency and Disclosure
5. Business Models for First Movers
6. Net Zero Goals and BECCS Integration
7. Cost Breakdown Approaches

Finally, in drawing the workshop to a close, Keith Burnard provided a brief historical reflection on the CCS Cost Network and reiterated its purpose as a platform for open exchange and collaboration. He thanked Bechtel for generously hosting the workshop, acknowledged the efforts of the Steering Committee and note takers, and extended appreciation to all presenters and attendees for their contributions to a successful 8th CCS Cost Network 2025 Workshop, Houston.

The next workshop is planned for the Summer of 2027 and will be hosted by SINTEF Energy.

Annex: Presentations

This annex includes presentations from all sessions and breakouts
(Note: A small number of slides may have been excluded or modified for public consumption)

Technical Session Presentation Slides

Session 1: Point Source Capture Front-End Engineering Design (FEED) Studies

1.1 Review of DOE-Sponsored FEED Studies for Retrofitting Existing Fossil Power Plants with Carbon Capture Technology

1.2 Commercial-Scale FEED Study for MTR's Membrane CO2 Capture Process

Session 2: CO_2 Transport Costs

2.1 Transport cost

2.2 U.S. Eastern Seaboard Transport and Storage Study: Summary of CO_2 Transport Costs

Session 3: Realistic Financing Assumptions

3.1 Finance Costs Drive CCS Cost: What Factors Drive Finance Costs?

3.2 Insights from Barclays (file redacted at author's request)

Session 4: Basis for CCS Costs Internationally

4.1 CCS Costs: Key Learnings from Emissions Reduction Alberta's Carbon Capture Kickstart (CCK) Program

4.2 Costing CCS for a modelling study

Session 5: Storage Cost Reduction

5.1 The "S" in CCUS: Cost Drivers for Onshore CO_2 Storage

5.2 CCUS: Cost of Drilling in North Dakota

5.3 Levelised cost of CO_2 Storage

Breakout Session Presentation Slides

Breakout 1: International CCS Drivers

6.1 International Drivers For CCS

Breakout 2: Moving towards 100% Capture

7.1 Net Zero Teeside

7.2 Moving towards 100% capture – is it Possible and is it Worth it?

7.3 100% capture of fossil CO_2: Should we do it?

Breakout 3: Impact of Plant Integration

8.1 Impact of Plant Integration

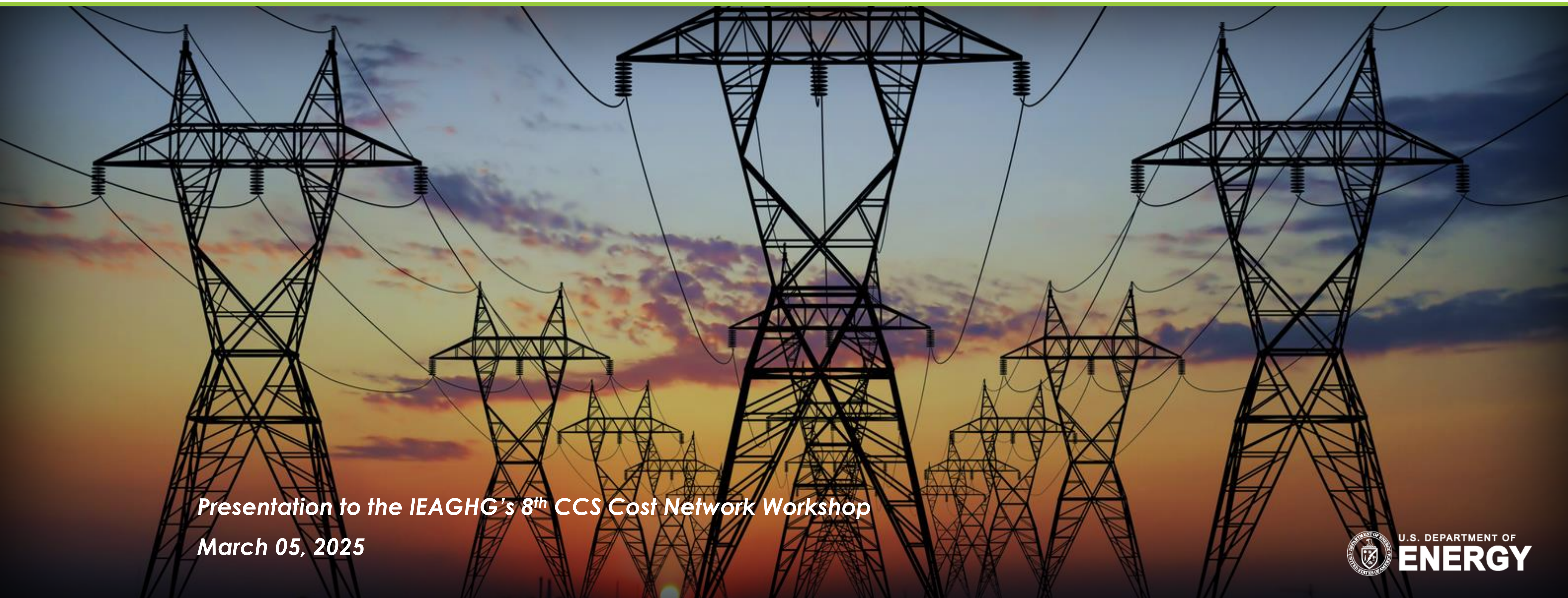
Session 1: Point Source Capture Front-End Engineering Design (FEED) Studies

1.1: Review of DOE-Sponsored FEED Studies for Retrofitting Existing Fossil Power Plants with Carbon Capture Technology

Review of DOE-Sponsored FEED Studies for Retrofitting Existing Fossil Power Plants with Carbon Capture Technology

Sally Homsy, PhD

NETL Energy Process Analysis Team



Presentation to the IEAGHG's 8th CCS Cost Network Workshop

March 05, 2025

Disclaimer

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Background: DOE-Sponsored FEED Studies

Since 2019, the Department of Energy Office of Fossil Energy and Carbon Management has been sponsoring front-end engineering design (FEED) studies on retrofitting the existing U.S. power fleet with state-of-the-art carbon capture technology

Award terms stipulate publication of a FEED study report

(Available on OSTI.gov)

In addition to investing in specific project maturation, this initiative informs DOE, technology developers, and the public of real-world considerations associated with point-source carbon capture at power plants

Background: Value of FEED Studies

FEED studies provide a unique opportunity for systems analysis and can advance understanding of capture system deployment

Techno-economic analysis (TEA) is the typical systems analysis tool used to examine the impact of design on the performance and cost of post-combustion carbon capture technologies

While TEA assumptions allow thoughtful comparison across different capture technologies, financial scenarios, and technology configurations and provide performance and costs representative for technology implementation under specific scenarios, TEA typically do not provide insight into the impacts of "steel-in-the-ground" project specifics

As post-combustion capture projects move towards deployment, the impacts of real-world project considerations—including site-specific design considerations, system integration challenges, operational dynamics, and relevant market conditions—on performance and cost need to be examined

Background: NETL FEED Study Review

A recent NETL article examines seven FEED studies and highlights how system design, performance, and cost are impacted by location-specific factors, host plant-specific factors, market conditions, business case incentives, and permitting requirements.

Interesting design considerations and opportunities for targeted RD&D efforts to address knowledge gaps are highlighted

ELSEVIER

International Journal of Greenhouse Gas Control

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Insights from FEED studies for retrofitting existing fossil power plants with carbon capture technology

Sally Homsy[a], Tommy Schmitt[a b], Sarah Leptinsky[a b], Hari Mantripragada[a b], Alexander Zoelle[a b], Timothy Fout[c], Travis Shultz[d], Ronald Munson[d], Dan Hancu[c], Nagamani Gavvalapalli[c], Jeffrey Hoffmann[c], Gregory Hackett[d]

[a] National Energy Technology Laboratory (NETL), 626 Cochrans Mill Road, Pittsburgh, PA 15236, USA

[b] NETL Support Contractor, 626 Cochrans Mill Road, Pittsburgh 15236, PA, USA

[c] Office of Fossil Energy and Carbon Management, U.S. Department of Energy, 1000 Independence Avenue, Washington 20585, DC, USA

[d] NETL, 3610 Collins Ferry Road, Morgantown 26505, WV, USA

Objective

1. Summarize findings reported in NETL's recently published FEED study review article

2. Build on the results with a quantitative analysis allowing comparative analysis across FEED studies

Reviewed FEED Studies

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Minnkota Power Cooperative, Inc.

- Site: Milton R. Young Station, ND
- Capture technology: Fluor Econamine FG PlusSM (EFG+)
- https://www.osti.gov/biblio/1987837

Membrane Technology and Research, Inc. (MTR)

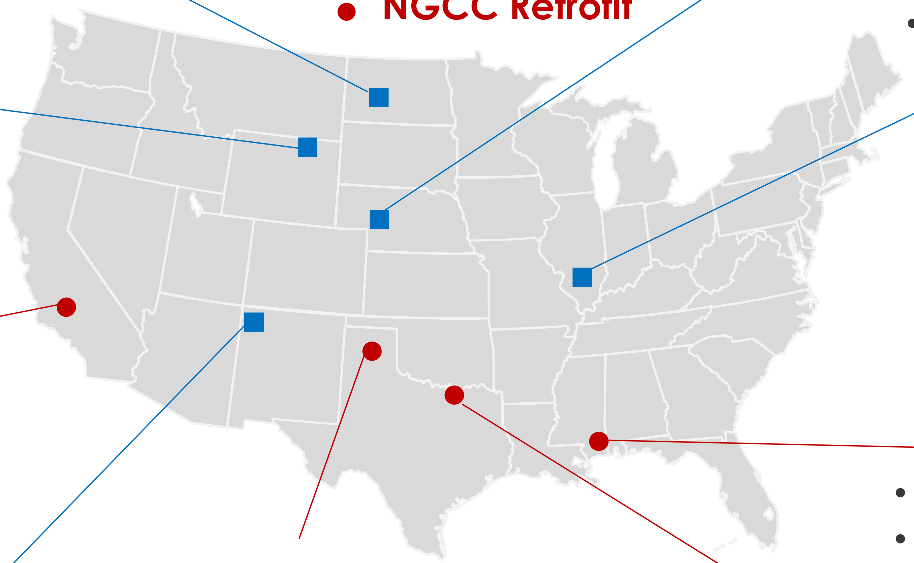
- Site: Basin Electric Dry Fork Station, WY
- Capture technology: MTR membranes
- https://www.osti.gov/biblio/1897679

Electric Power Research Institute, Inc. (EPRI)

- Site: California Resources Corporation Elk Hills Power Plant, CA
- Capture technology: Fluor Econamine FG Plus℠
- https://www.osti.gov/biblio/1867616

Enchant Energy, LLC (Enchant)

- Site: San Juan Generating Station, NM
- Capture technology: Mitsubishi Heavy Industries America (MHIA) KM CDR Process™
- https://www.osti.gov/biblio/1889997



The University of Texas at Austin (UT)

- Site: Golden Spread Electric Cooperative Mustang Station, TX
- Capture technology: Piperazine Advanced Stripper (PZAS™) process
- https://www.osti.gov/biblio/1878608

ION Engineering LLC

- Site: Nebraska Public Power District Gerald Gentleman Station, NE
- Capture technology: ION
- https://www.osti.gov/biblio/1963720

Board of Trustees of the University of Illinois (UIUC)

- Site: Prairie State Generating Company Energy Campus, IL
- Capture technology: MHIA's KM CDR Process™
- https://www.osti.gov/biblio/1879443

Southern Company Services, Inc.

- Site: Southern Company Plant Daniel, MS
- Capture technology: Linde-BASF OASE® blue solvent
- https://www.osti.gov/biblio/1890156

Bechtel National, Inc.

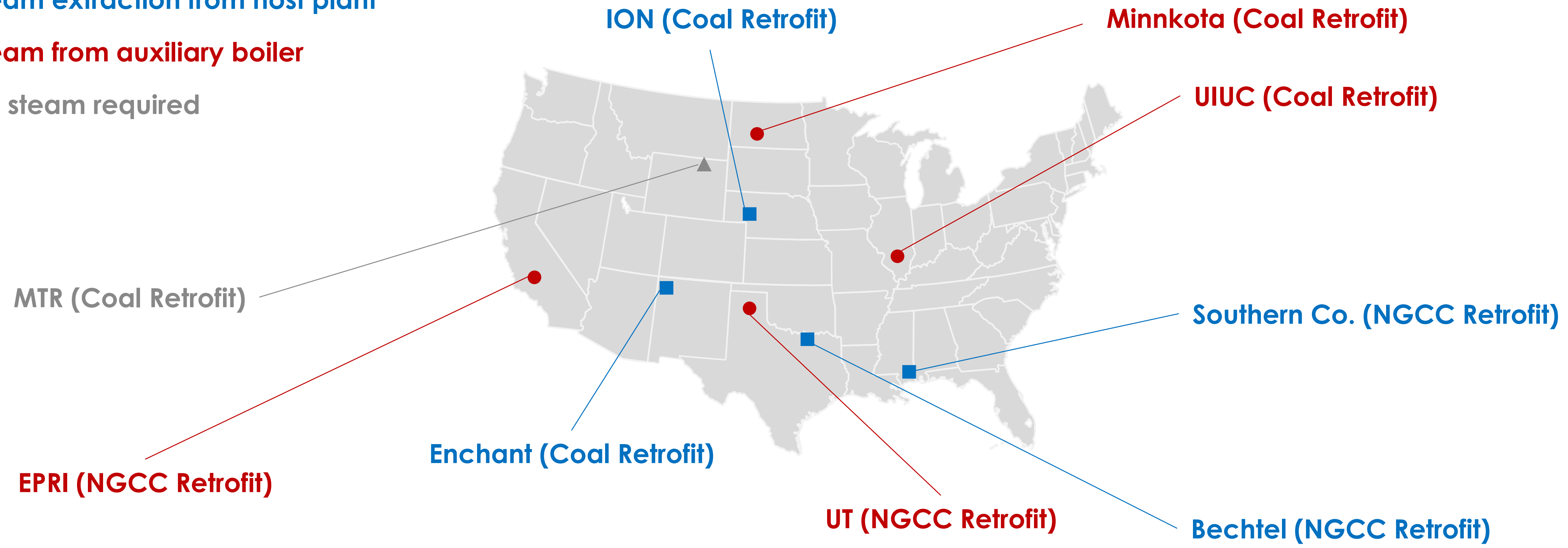
- Site: Panda Power Sherman Power Plant, TX
- Capture technology: 35 wt% MEA
- https://www.osti.gov/biblio/1836563

FEED Study Review Findings

Steam Extraction From the Host Plant Was Preferred

In all cases, the design decision to utilize auxiliary steam generation was motivated by host plant-specified restrictions against steam extraction; host plants either could not accommodate reductions in performance or were concerned that modifications would impact system reliability.

- ■ Steam extraction from host plant
- ● Steam from auxiliary boiler
- ▲ No steam required



Steam Extraction From the Host Plant Impacts Water Availability

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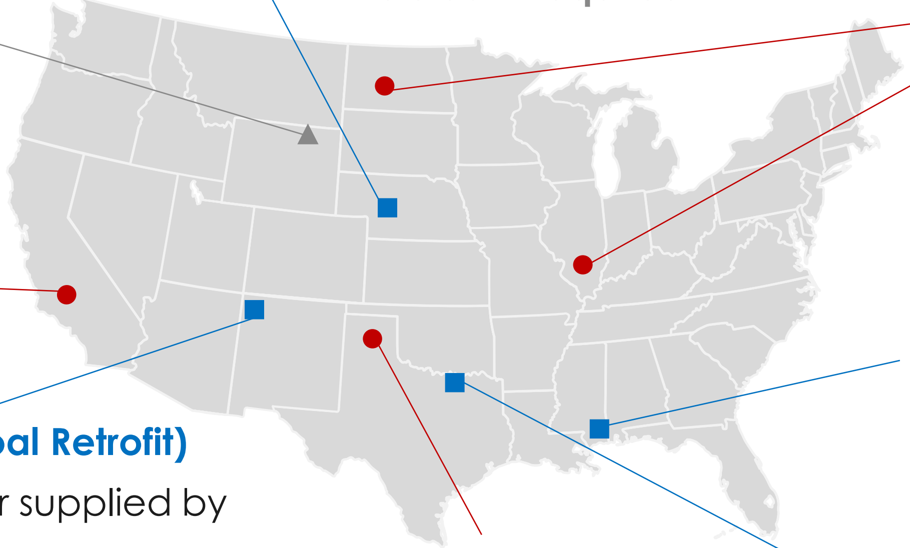
In configurations utilizing steam from the host plant, overall performance and cost are not only impacted by eliminating the dedicated steam generation systems but also by increasing water availability.

Steam extraction: ↓ steam cycle condenser duty ↓ the host plant's cooling water and raw water demand

■ Steam extraction from host plant
● Steam from auxiliary boiler
▲ No steam required



MTR (Coal Retrofit)
- Water constrained
- Dedicated systems:
  - Supply water treatment
  - Wastewater treatment
  - WSAC

ION (Coal Retrofit)
- Hybrid cooling

UIUC & Minnkota (Coal Retrofit)
- Assume permitting will be granted
- Dedicated systems:
  - Supply water treatment
  - Cooling tower
  - Wastewater treatment

EPRI (NGCC Retrofit)
- Water constrained
- Dedicated systems:
  - Wet surface air cooler (WSAC)
  - Dry cooling
  - Glycol cooling
  - Cooling tower
  - Wastewater treatment

Enchant (Coal Retrofit)
- Sufficient water supplied by host plant
- Dedicated systems:
  - Cooling tower
  - Wastewater treatment

UT (NGCC Retrofit)
- Water constrained
- Dedicated system:
  - Dry cooling

Southern Co. (NGCC Retrofit)
- Sufficient water supplied by host plant
- Dedicated system:
  - Cooling tower system (for critical operating scenarios)

Bechtel (NGCC Retrofit)
- Sufficient water supplied by host plant
- No dedicated systems

The Combined Impacts of Steam Extraction and Water Availability Impact System Cost

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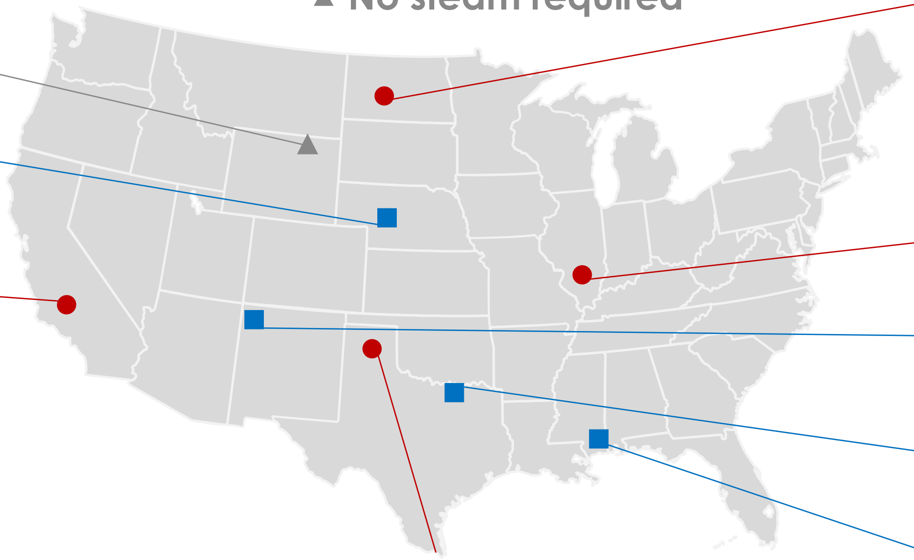
Utilizing hybrid and air-cooling systems to achieve temperatures comparable to cooling tower systems is cost prohibitive, and higher operating temperatures negatively impact the performance and cost of amine-based capture systems. Hybrid and air-cooling systems are less efficient, require a substantial land footprint, and increase the cost of the associated projects.

■ Steam extraction from host plant
● Steam from auxiliary boiler
▲ No steam required



MTR (Coal Retrofit)
Hybrid cooling

ION (Coal Retrofit)
Hybrid cooling

EPRI (NGCC Retrofit)
Hybrid cooling
Opting for steam extraction from the host plant can reduce the capital cost by an estimated \$35M–45M (13–16% of the balance of plant [BOP] cost) by eliminating the need for auxiliary boilers and five of the eight WSAC units.

UT (NGCC Retrofit)
Dry cooling
Dry cooling system contributes 12.9% of the total project cost, with the absorber being the second-largest cost contributor, responsible for 5.3% of the cost.

Minnkota (Coal Retrofit)
Water cooling
Due to higher costs than expected, recommend revising steam extraction

UIUC (Coal Retrofit)
Water cooling

Enchant (Coal Retrofit)
Water cooling

Bechtel (NGCC Retrofit)
Water cooling

Southern Co. (NGCC Retrofit)
Water cooling

Data Gaps Exist Regarding Host Plant Integration

Uncertainty exists regarding the impact of steam extraction options on host plant performance and operability (RD&D recommended).

- Host plants were reportedly concerned that steam cycle modifications could impact system reliability.
- The Southern Co.-led FEED study report includes a detailed evaluation of steam sourcing and condensate return configurations. Impact of specific configurations on host plant operating flexibility, overall heat rate, capacity, complexity, and capital cost are reported. The ION FEED study also examines different configurations with OEM input. The complexity, uncertainties, and challenges associated with integration are highlighted—while extraction from the LP/IP crossover is typically cited, these studies highlight that the specifics of the integration require further consideration.

Uncertainty exists regarding stack tie-in options (RD&D recommended).

- The use of diverter dampers at the stack is disputed; the risk associated with pulling a vacuum in the flue gas duct and direct contact cooler or impacting backpressure at the HRSG and gas turbine versus the costs associated with uncontrolled air ingress need to be weighed.

Host Plant Operational Mode and Capacity Factor Significantly Impact the Business Case

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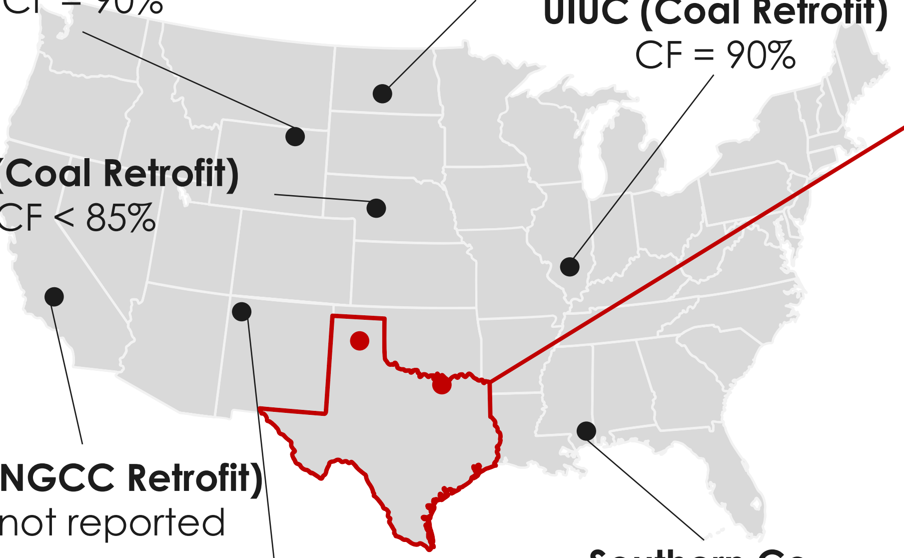
With increased renewable penetration in global energy systems, the fossil-powered plant capacity factor (CF) may reduce over time.

Future incentives could positively impact the business case for fossil-fueled plants fitted with capture technology. The CF for plants fitted with capture may increase due to preferential dispatching of "clean power", and the electricity sales realizations may increase with a "clean energy" designation.



UT (NGCC Retrofit)
CF = 52%

Sized to maximize abatement:

- 100% of NGCC emissions are treated when the NGCC plant is operated at full load; this leads to stranded assets when the NGCC is turned down.
- Business case analysis concludes that increasing the CF from 52% to 85% can reduce the cost of CO_2 captured by $40/tonne.

Bechtel (NGCC Retrofit)
CF = 57%

Sized to maximize usage of the capture system:

- 100% of NGCC emissions are treated when the NGCC plant is operated at its minimum load, and 68% of NGCC emissions are treated when the plant is operated at maximum load.

Data Gaps Regarding Solvent Reclamation Exist

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Uncertainty regarding solvent reclamation requirements exists (RD&D recommended).

- The Bechtel study notes uncertainties in the reclaimer regime and asserts that reclaimer operation, design, performance, and cost may need to be revisited after an on-site testing period.
- The UT FEED report notes a lack of data pertaining to piperazine degradation due to NO_X exposure and states that the system design, both upstream flue gas pretreatment and/or solvent reclamation, may need to be revisited.

Data Gaps Regarding Air Emission Control Requirements Exist

Uncertainties related to air emissions exist. Clearer permitting pathways and requirements, which will dictate emissions profiles, may emerge as projects progress.

- The subject funding opportunity announcement (FOA 2058) does not require minimization of air emissions beyond what was necessary for the CO_2 capture process and emissions permitting; therefore, the reviewed projects were not designed or optimized to minimize or mitigate ancillary air emissions*.
- The design of pollutant emissions control equipment is not finalized in the FEED studies due to uncertainty associated with system emissions and permitting requirements.
- Inclusion of additional control equipment can negatively impact the overall system performance, cost, and construction schedule.
- These uncertainties and their impacts may be reduced with increased understanding of the impact of plant-specific impurities on capture system emissions and by clearer permitting pathways.
- Multiple permitting pathways with different requirements (e.g., expanding existing permitting versus obtaining standalone permitting) are being explored by the various projects.

* FEED studies were completed prior to EPA's publication of its proposed rule for greenhouse gas emissions from fossil fuel-fired steam-generating units that undertake a large modification (88 FR 33240, published 23 May 2023)

Modularization and Constructability Impacts the Number of Capture Trains

Physical equipment sizing, the relationship between measured performance at a small scale and expected performance at a large scale, risk reduction for initial projects, turndown accommodation, and modularization for site accessibility can influence equipment size.

While system modularization, pre-fabrication, and pre-assembly can reduce costs, compress the construction timeline, and enhance worker safety, this approach is limited by accessibility to the site.

Parameter	NGCC Retrofit				Coal Retrofit	
	Southern Co.	UT	EPRI	Bechtel	UIUC	Enchant
Design basis flue gas, m^3/s	1,050	1,050	725	740	1,800	1,860
Turndown	61%	58%	40%	50%	50%	43%
Capture trains	4*	2	1	2*	4	2
Absorber vessel	Cylindrical	Rectangular 12x14x36 m	Not reported	Cylindrical 12x44 m	Not reported (MHIA)	Not reported (MHIA)
Reasoning provided for number of trains	--	--	--	Limited data from internal suppliers supporting operation for >15 m diameter cylindrical vessels	Absorber and quencher modularized for shipping	Accessible for delivery of large modules; maximum equipment sizing

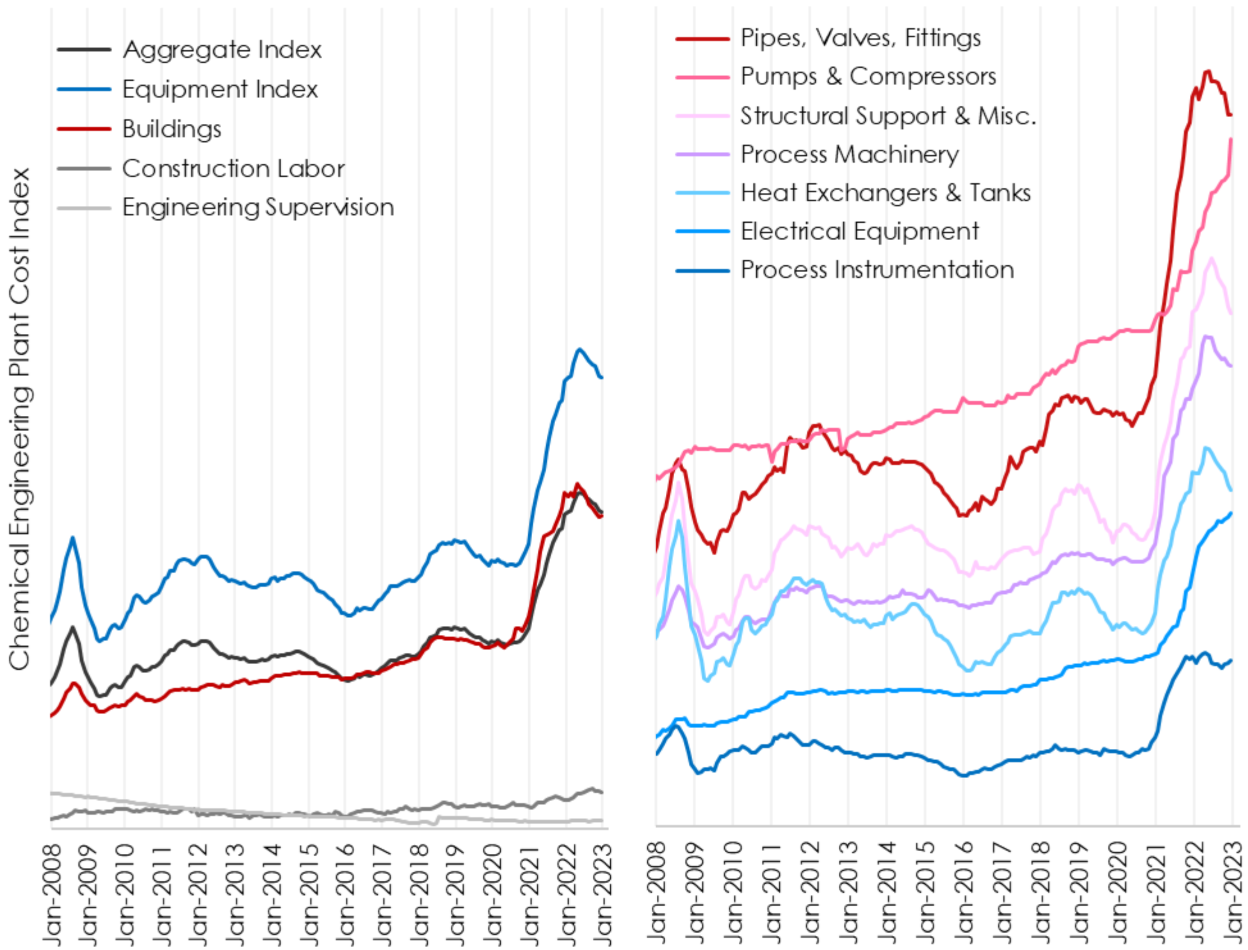
*Two absorbers share one regenerator

Quantitative Analysis Methodology

Cost Comparison Disclaimer

Direct Cost Comparison is Inadvisable

- **Costs were developed over a period of significant market variability (2020–2022)**
- **Costs were not developed on a similar basis** (different costing assumptions were made across projects), and capital and operation and maintenance (O&M) costs were defined differently across projects (different tax assumptions, escalation, owner's cost assumptions, insurance, etc.)
- **Costs were impacted by many different inextricable factors**, such as sparing philosophies, local labor rates, geotechnical impacts, ambient conditions, climatic conditions, and other project-specific constraints that lead to different design choices



Quantitative Analysis Approach

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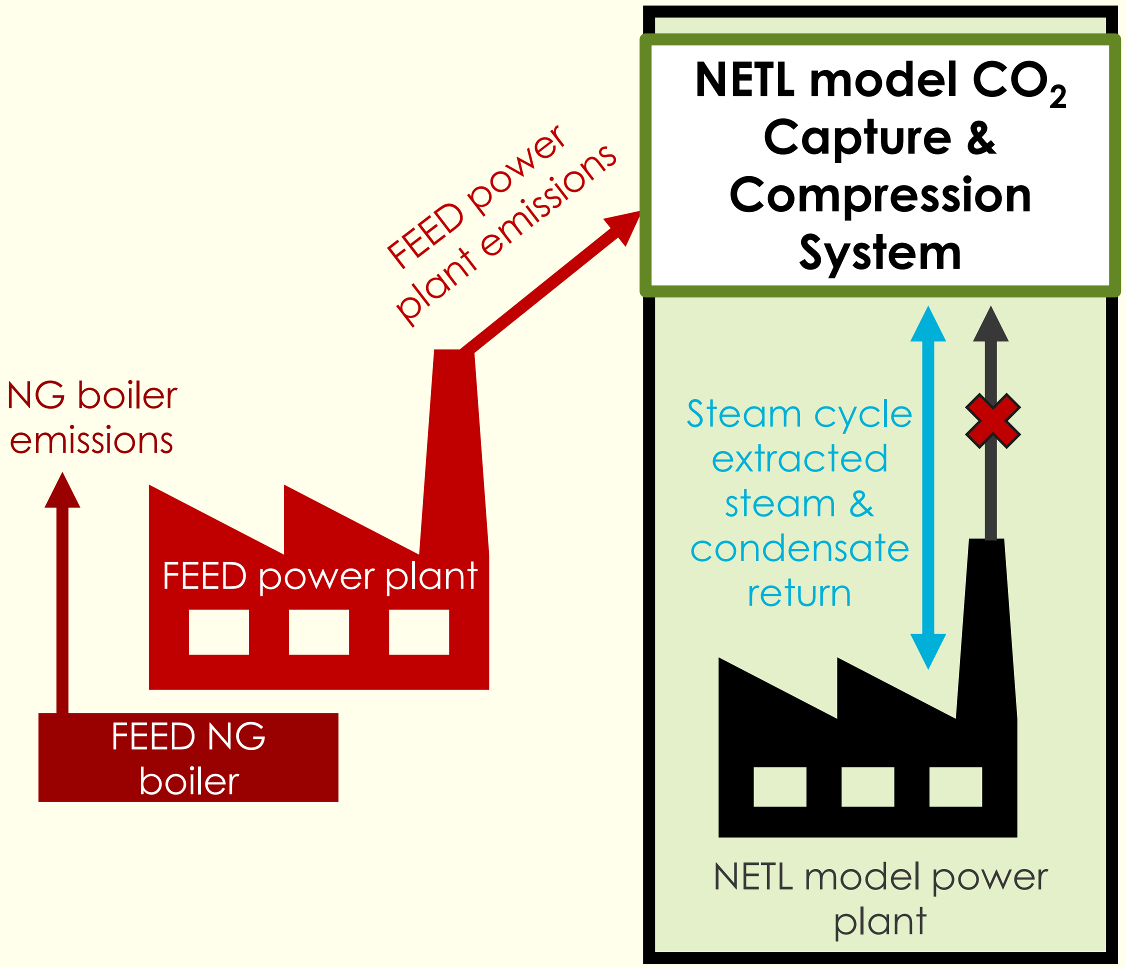
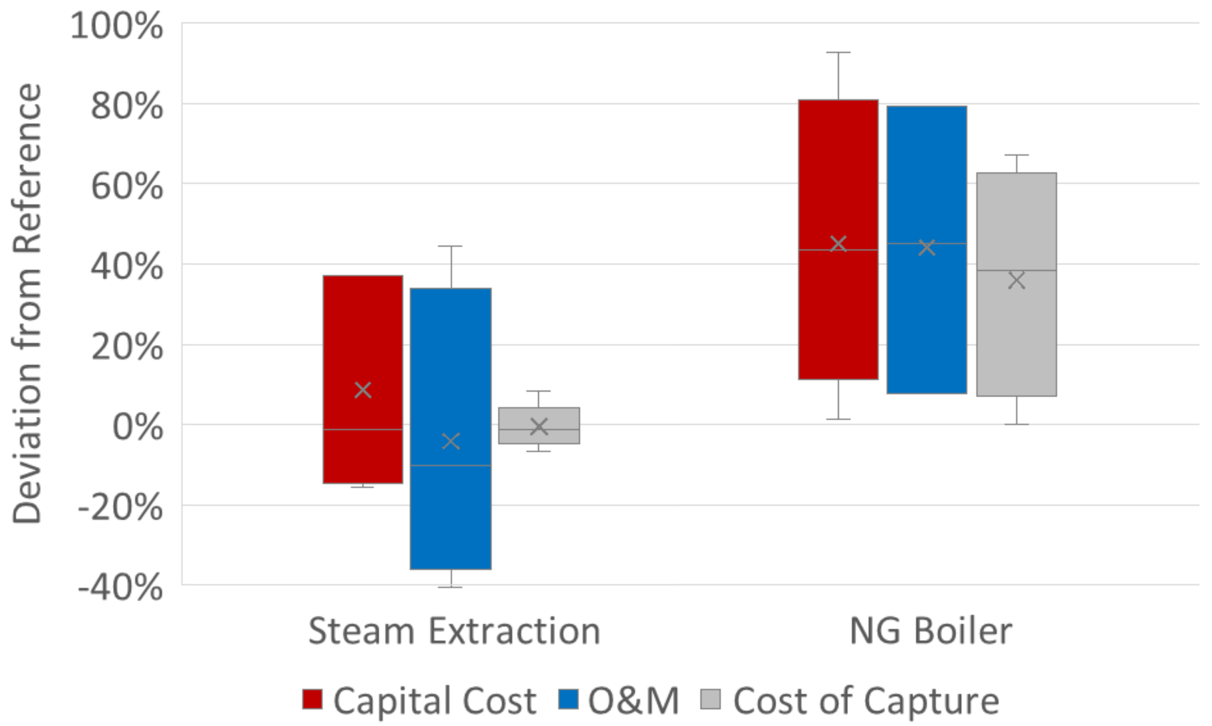
1. For each FEED study cases, analogous modified NETL modeled reference cases were developed. The modeled cases represent idealized cases developed on a common basis and not impacted by site-specific factors of interest.
2. Calculating the % deviation of each FEED study from its respective idealized case provides insight into the impact of the site-specific factors.
3. Examining the distribution of cost deviation across FEED studies allows for statistical trends to emerge.

Quantitative Analysis Approach: e.g., Impact of Opting for an Auxiliary Boiler

Reference Cost Calculation



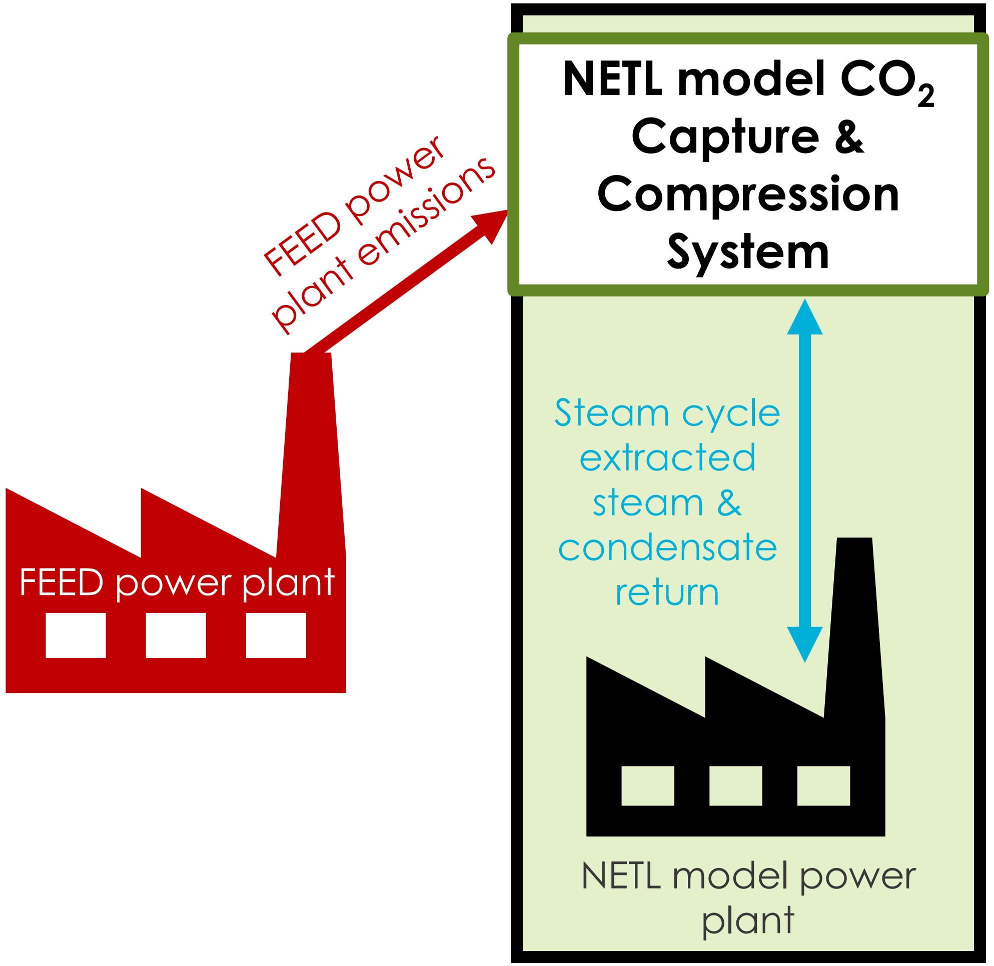


Statistical trends emerge when costs are compared to a reference case*

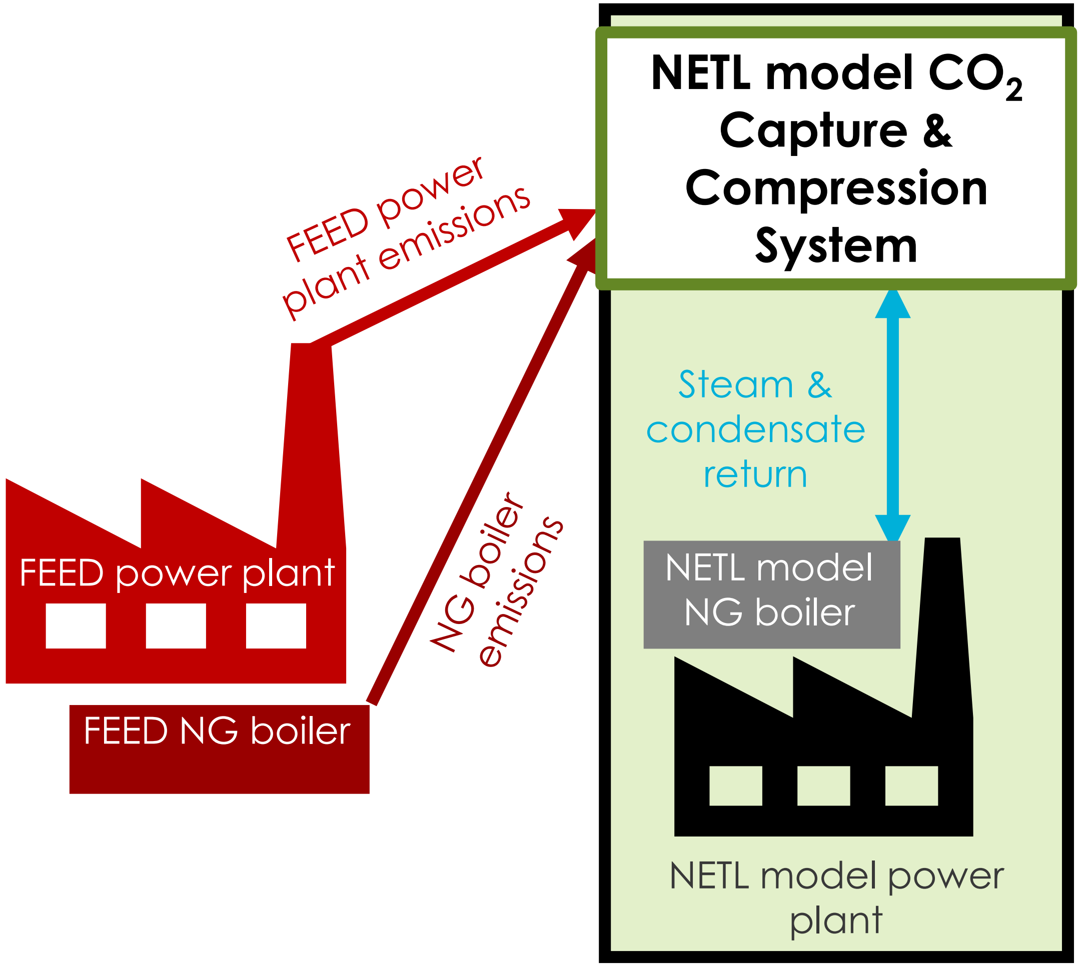
*Results are tied to fuel and energy costs

Quantitative Analysis Approach: e.g., Impact of Capture Trains

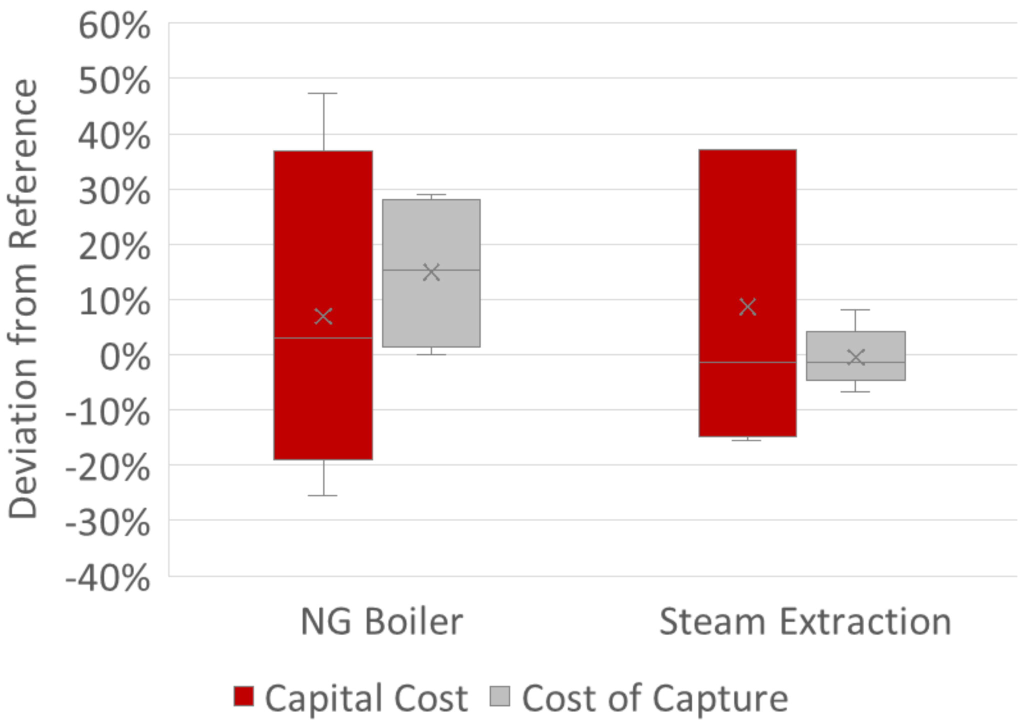
Scenario 1 Reference Cost Calculation

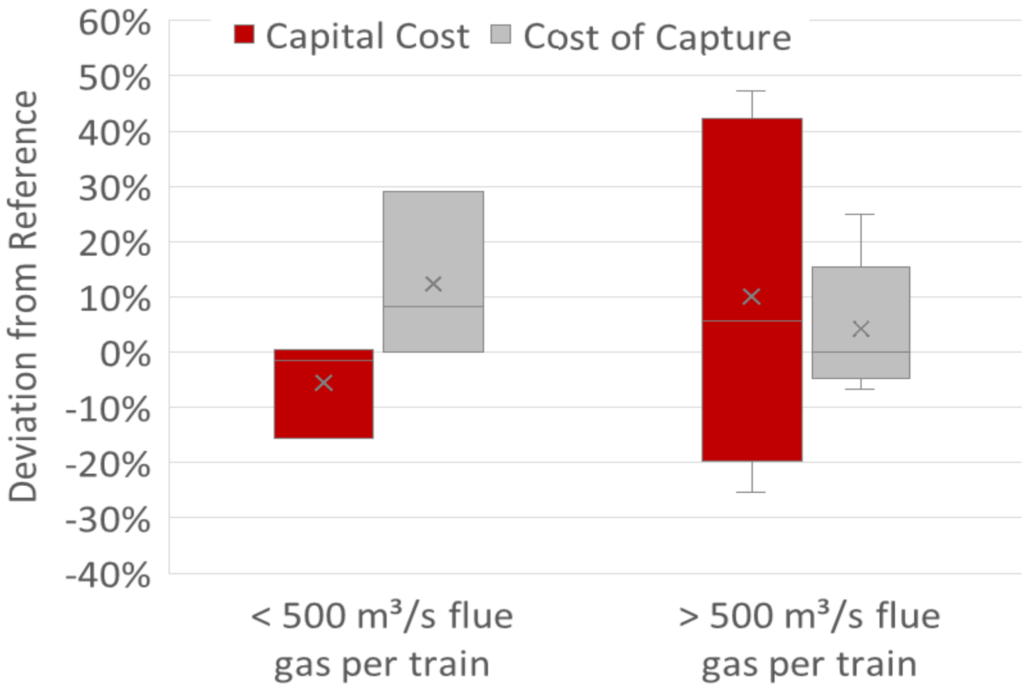


Scenario 2 Reference Cost Calculation



Quantitative Analysis Approach: e.g., Impact of Capture Trains

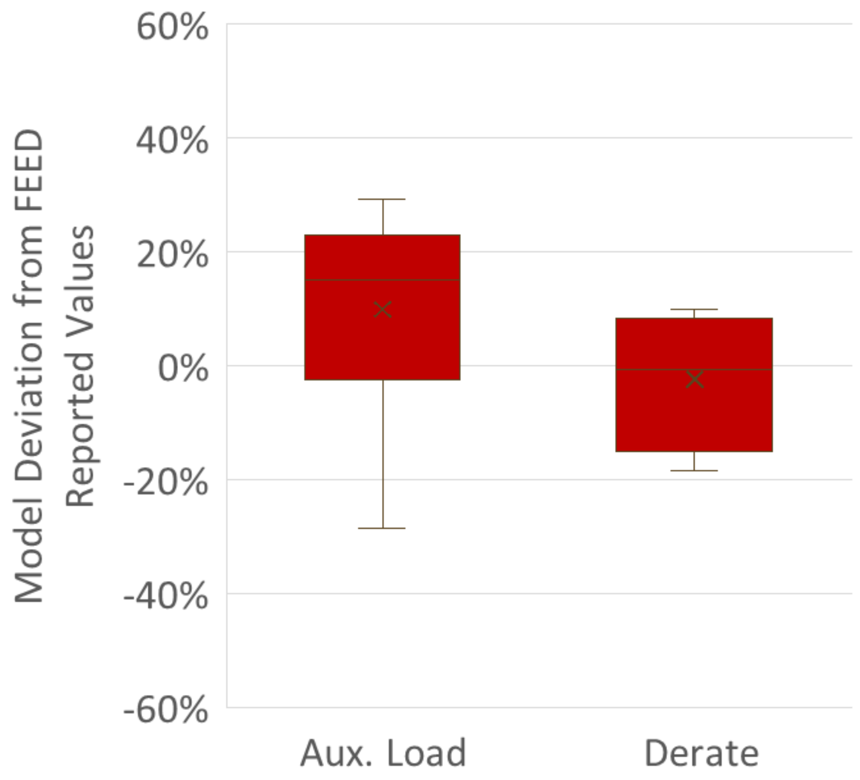




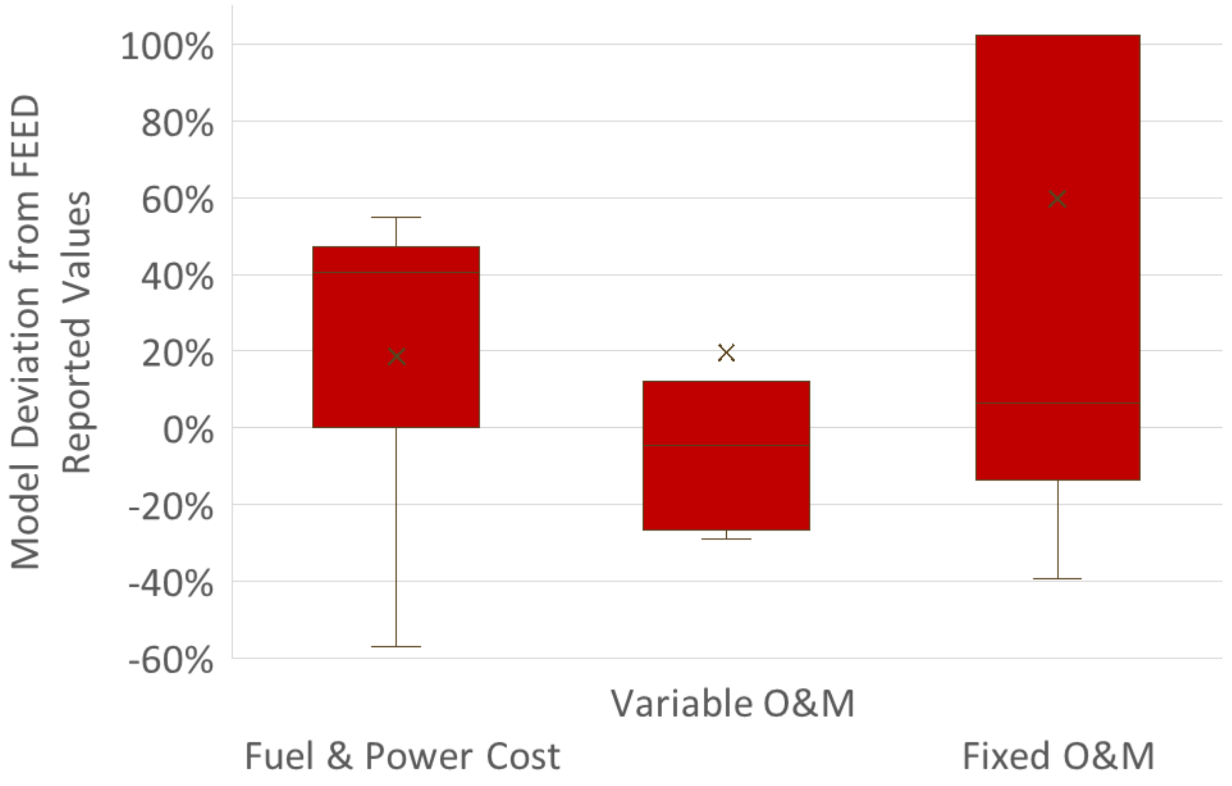
Deviation from the appropriate reference is within expected uncertainty

No trend is observable regarding the impact of number of trains on cost

Cost Comparison Learnings for Future TEA



NETL models predict performance reasonably well—deviations beyond 20% can be reasonably explained



Do not predict O&M costs well but provide sufficient granularity for highlighting where discrepancies lie: fuel and power price, solvent costs and reclaimer waste disposal costs, tax and insurance, labor rates

Recap, On-Going and Future Work

- DOE-sponsored, publicly available FEED study reports contain valuable information that can guide future system design, spur R&D, and accelerate learning rates
- NETL continues to review and provide feedback on incoming FEED studies, to include forthcoming power, industrial, biomass plants, and carbon dioxide removal FEED studies
- Developing a similar publication summarizing the results from recently completed industrial CO_2 capture pre-FEED studies
- NETL models to be adapted/expanded where appropriate based on gaps identified when comparing to FEED study results

Questions/ Comments

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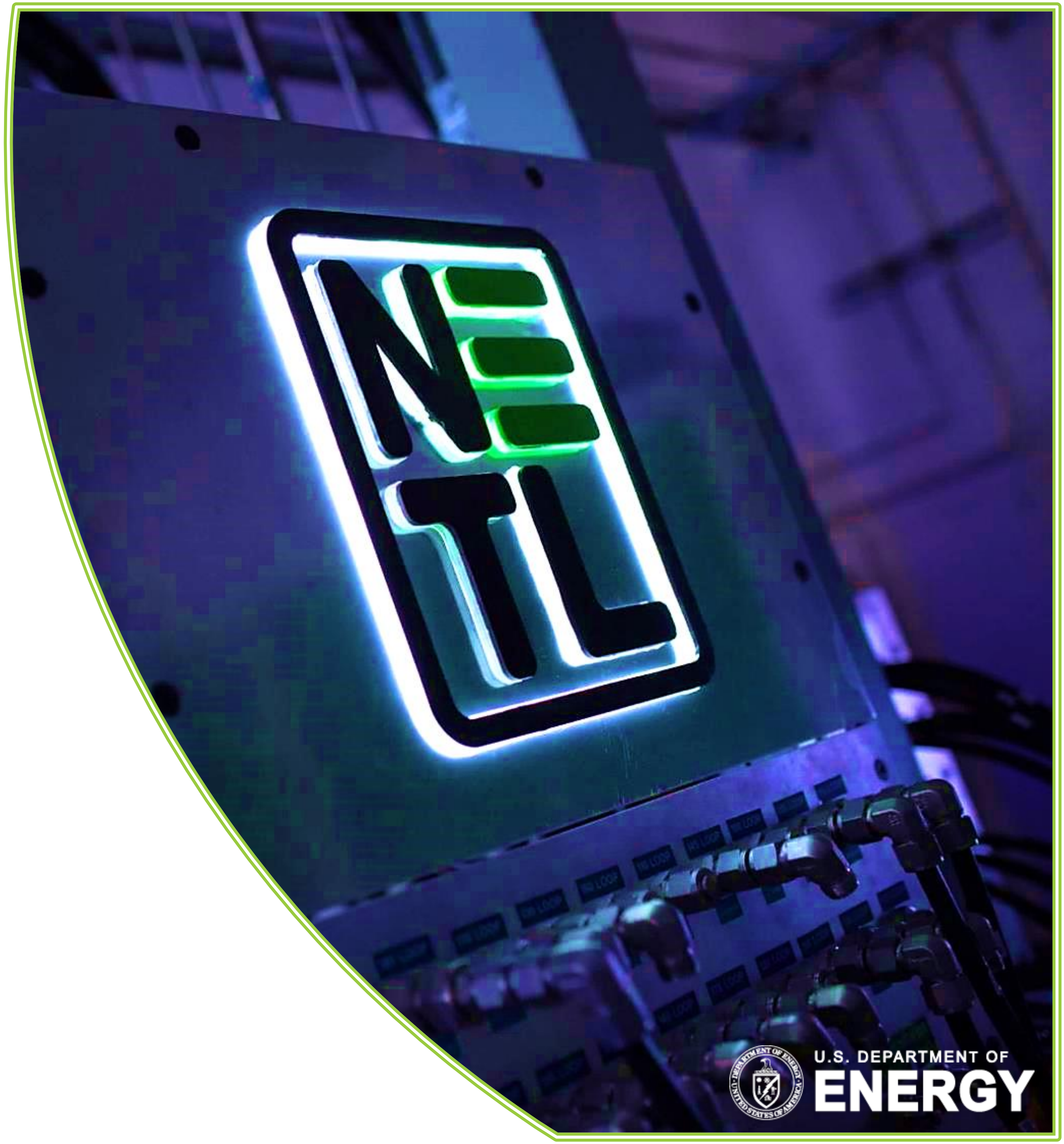
CONTACT:

Sally Homsy Sally.Homsy@netl.doe.gov
Greg Hackett Gregory.Hackett@netl.doe.gov



1.2: Commercial-Scale FEED Study for MTR's Membrane CO_2 Capture Process

Commercial-Scale FEED Study for MTR's Membrane CO_2 Capture Process

- DE-FE0031846; FOA-2058 (2019)
- 10/1/19 to 6/30/22 (32 months)
- $6.40M total project cost
- Conduct a FEED study of MTR's capture process applied to Basin Electric's 440 MWe Dry Fork Station
  - Engineering design package
  - Integration plans
  - 3D plant model
  - Constructability plan
  - AACE Class II costs estimated (±15%)
- Coordination with Wyoming CarbonSAFE

MTR CARBON CAPTURE | BASIN ELECTRIC POWER COOPERATIVE A Touchstone Energy® Cooperative | Sargent & Lundy | EPRI ELECTRIC POWER RESEARCH INSTITUTE | TRIMERIC CORPORATION | CARBON MANAGEMENT STRATEGIES | NETL NATIONAL ENERGY TECHNOLOGY LABORATORY

Development Timeline

17 Year
Relationship with DOE

20+
DOE Awards

>$140mm
Total Funding Received from U.S. Government Agencies

DOE support spanned early TRL lab-scale development through multiple field trials, culminating in the Large Pilot project at the Wyoming ITC and now the full-scale, full-chain OCED Demo

Development Timeline

Initial Feasibility

Arizona Public Service Red Hawk NGCC Pilot

Arizona Public Service Cholla Coal Pilot

National Carbon Capture Center 1 MWe Pilot

Low Pressure Mega Module

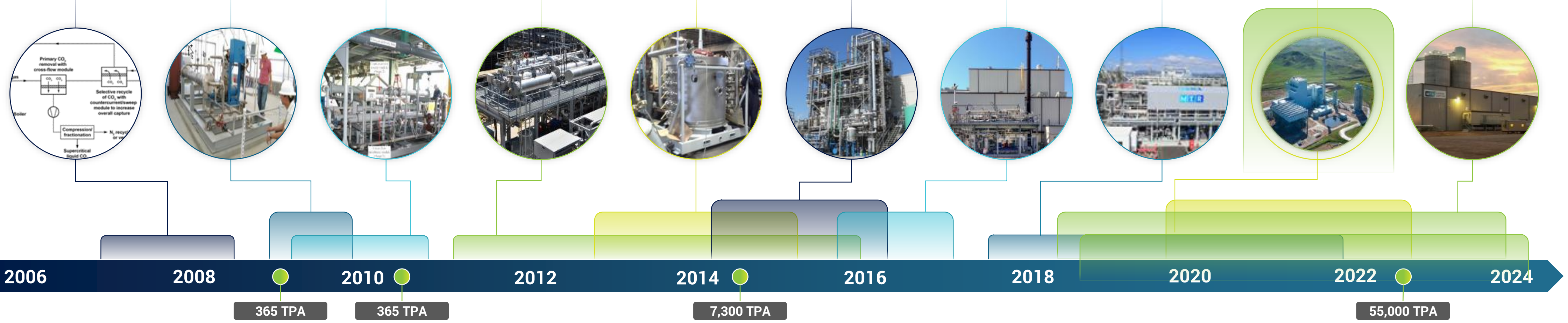
Hybrid Capture with amine

Babcock and Wilcox Integrated Test

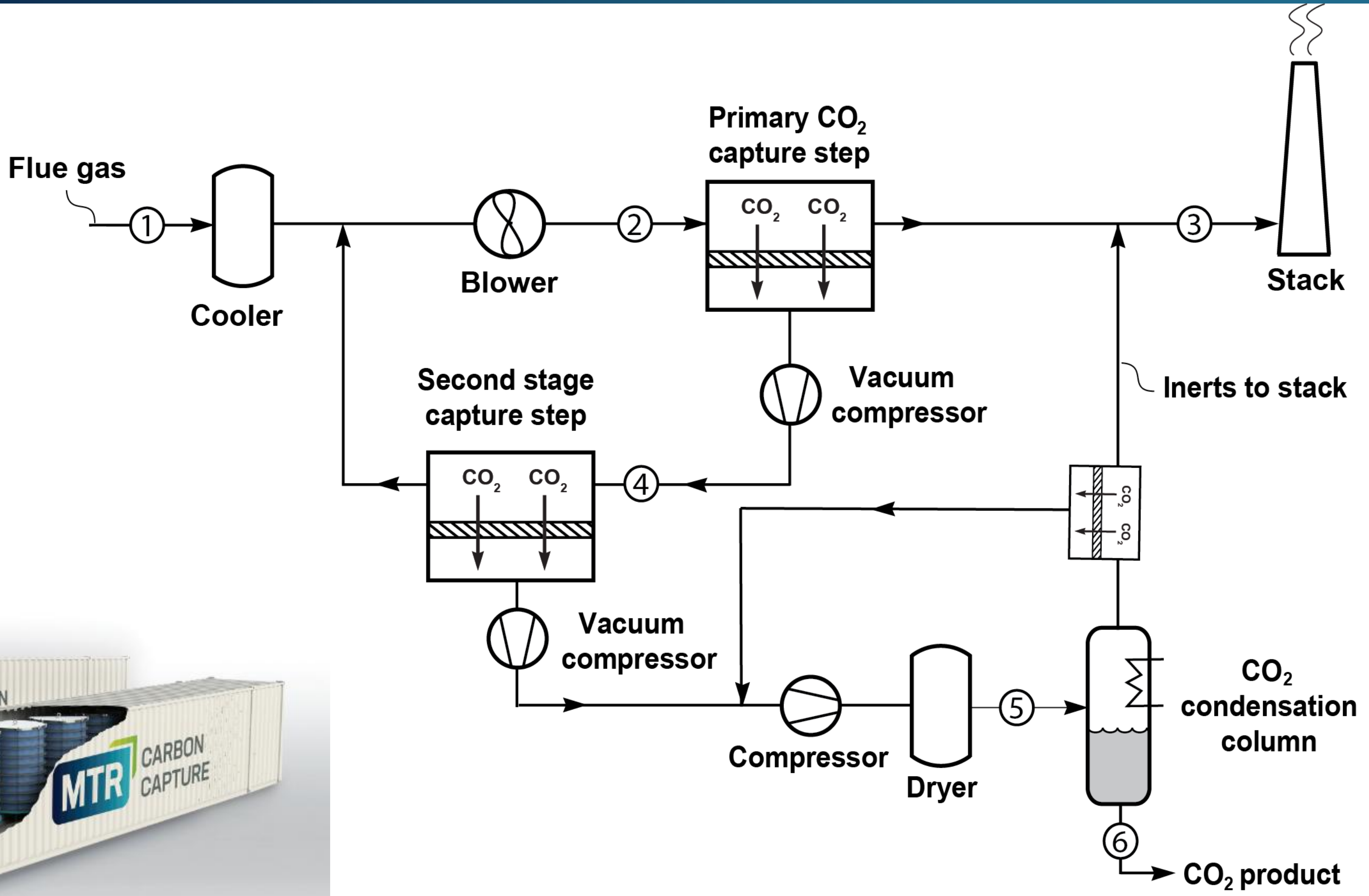
Technology Centre Mongstad Pilot

Full-scale FEED Dry Fork Station

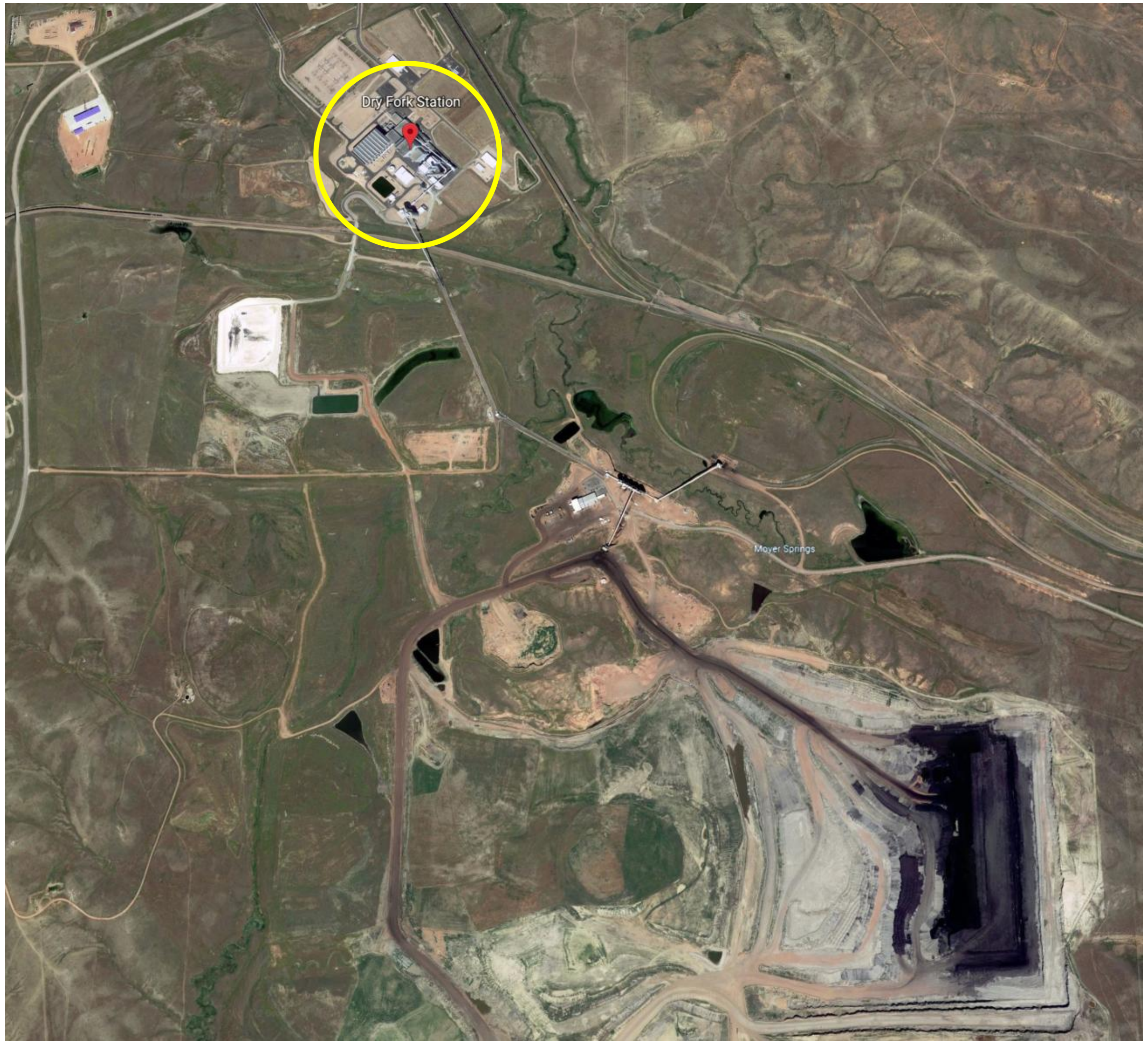
Large Pilot Wyoming ITC



Simplified Process Flow Diagram



Project Location – Gillette, Wyoming



Basin Electric's Dry Fork Station

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy® Cooperative

WMPA
WYOMING MUNICIPAL POWER AGENCY

- Single unit, 445 MWe coal fired power plant in Gillette, WY (4,500')
- Commissioned in 2011
- Low sulfur, sub-bituminous PRB coal from the Dry Fork Mine
- Zero liquid discharge facility
- Low NOx burners w/ OFA, SCR, dry lime fluidized bed, ACI, FF
- Cooling via an air-cooled condenser
- 12.0% CO_2, flue gas at 222°F (106 °C)
- **Home to the Wyoming Integrated Test Center**
- **Home to the Wyoming CarbonSAFE project**

Design Requirements from Basin Electric

- Operate under DFS's current well water permit (no significant new water withdrawals)
- Develop a Zero Liquid Discharge (ZLD) capture plant solution
- No new restrictions on DFS's operability
- Simple and fast interconnection
- Plant confined to existing plot (< 4.0 acres)
- Lowest possible cost-of-capture
- CO_2 to CarbonSAFE wells w/ option for GreenCore CO_2 pipeline

DE-FE0031846

MTR CARBON CAPTURE

Existing Stack Re-Use Investigation

The addition of carbon capture changes the flue gas:

- Less mass (3.7M vs 5.1M lb/hr flue gas)
- Cooler (106 vs 222° F)
- Drier (<1% vs 18.8% mol. H_2O)

Dispersion modeling performed by S&L for five cases:
current condition + added carbon capture with and w/out reheat

- SO_2 concentrations < NAAQS
- NO_2 concentrations < NAAQS

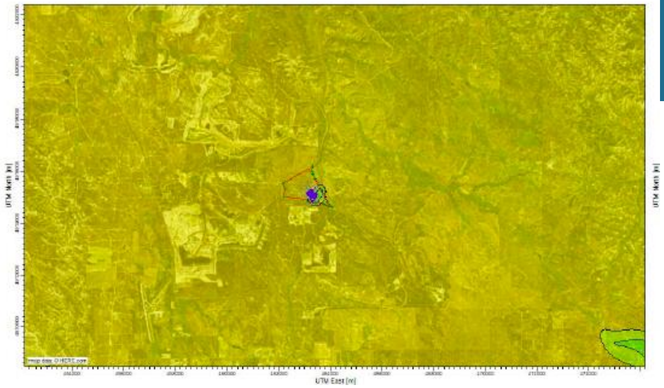
Moisture Concentration – no visual impacts/plume downwash

Finding: Reheat of the plume is not required

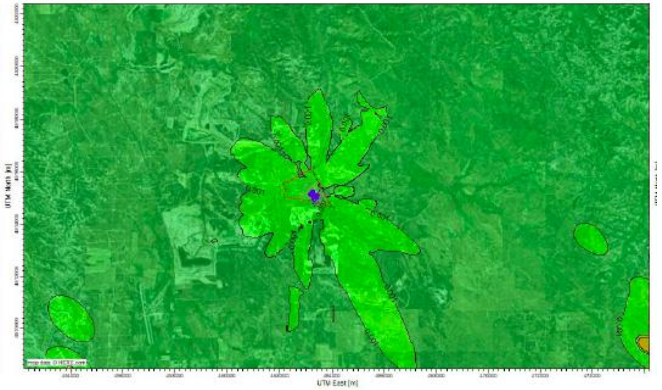
AERMOD Ground-Level Concentration Plots

0.0-0.001 g/m³	0.001-0.009 g/m³	0.009-0.01 g/m³	0.01-0.05 g/m³	>=0.05 g/m³

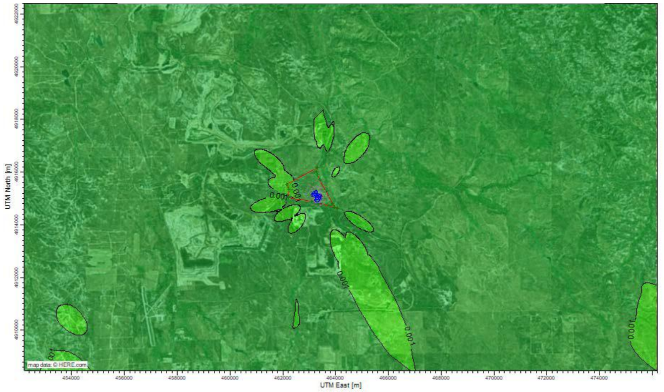
Current Conditions



Carbon Capture – No Reheat

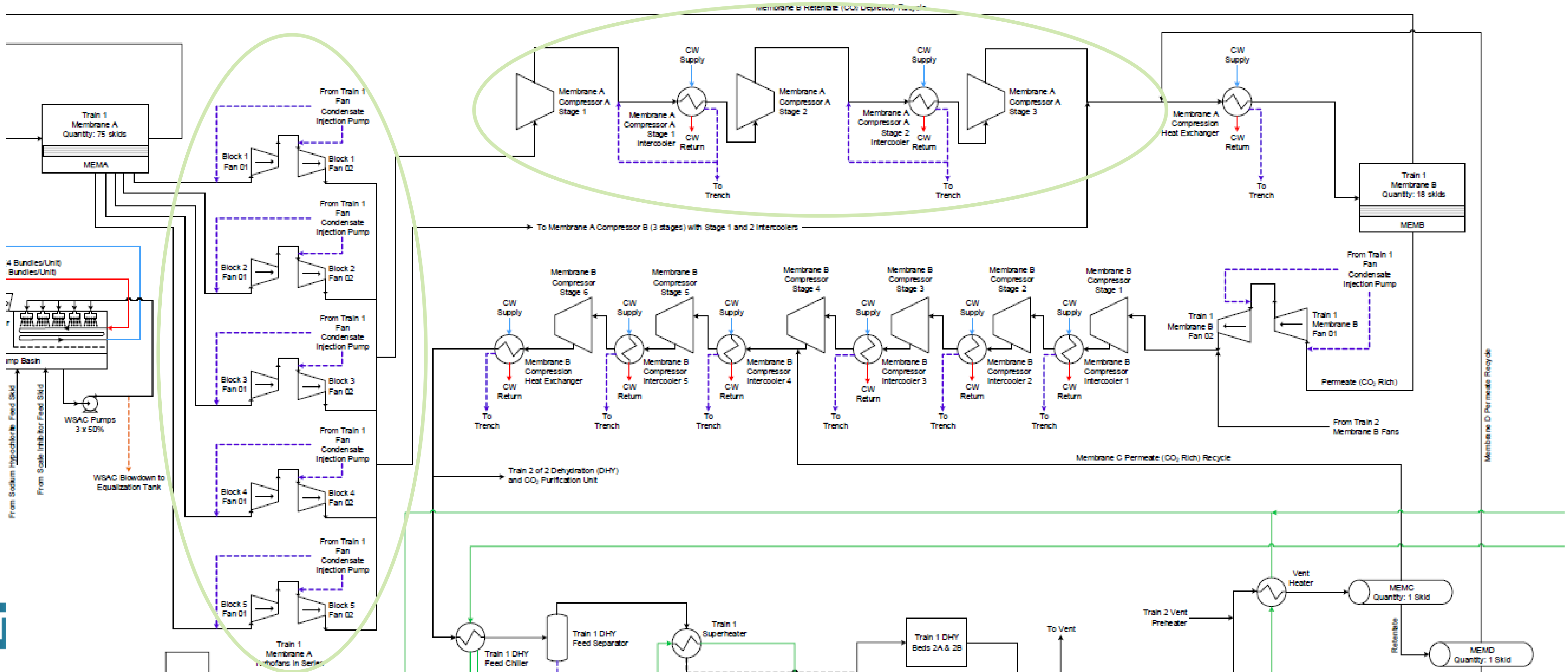


Carbon Capture – with Reheat



Permeate Compression Equipment Selection

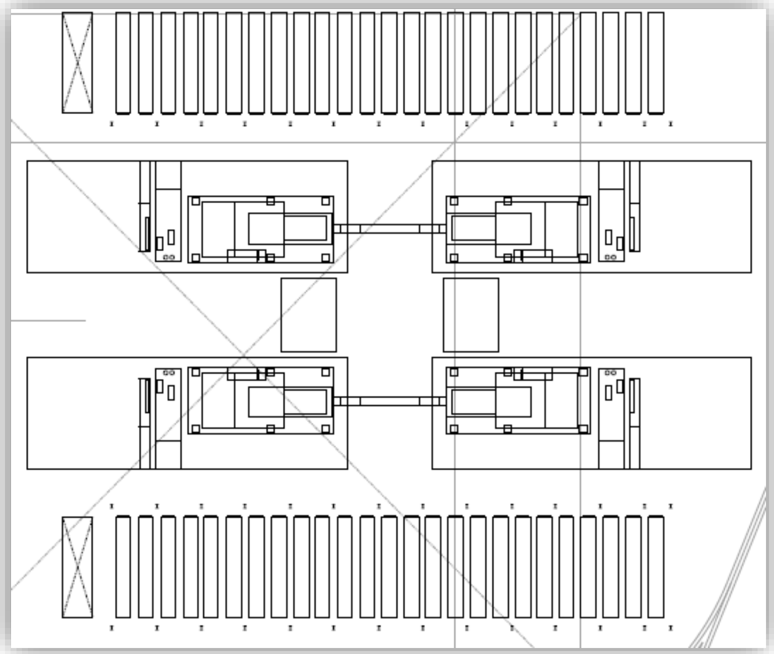
Prior to starting the detailed system design, the team evaluated several permeate compression options to determine the most cost-effective solution



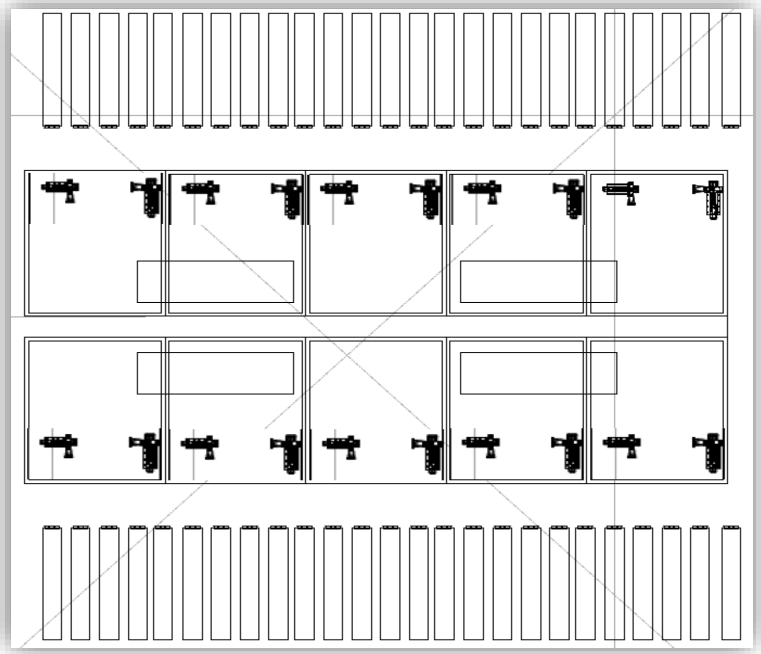
Considerations for Process Equipment Selection

- Identifying the "best" process equipment starts with process simulations
- Is further informed by OEM vendor input
- But is **only really understood** once an EPC provides their input

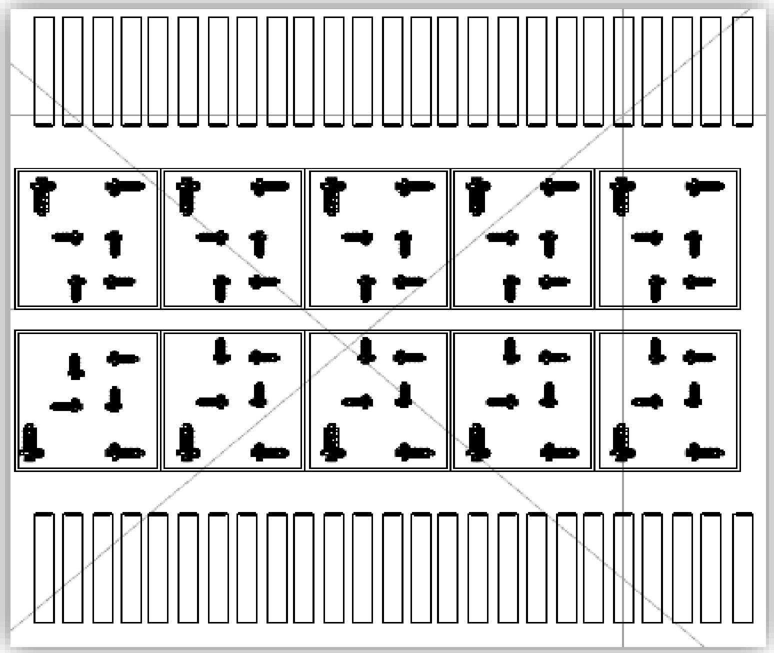
Compressors Only



Fans + Compressors



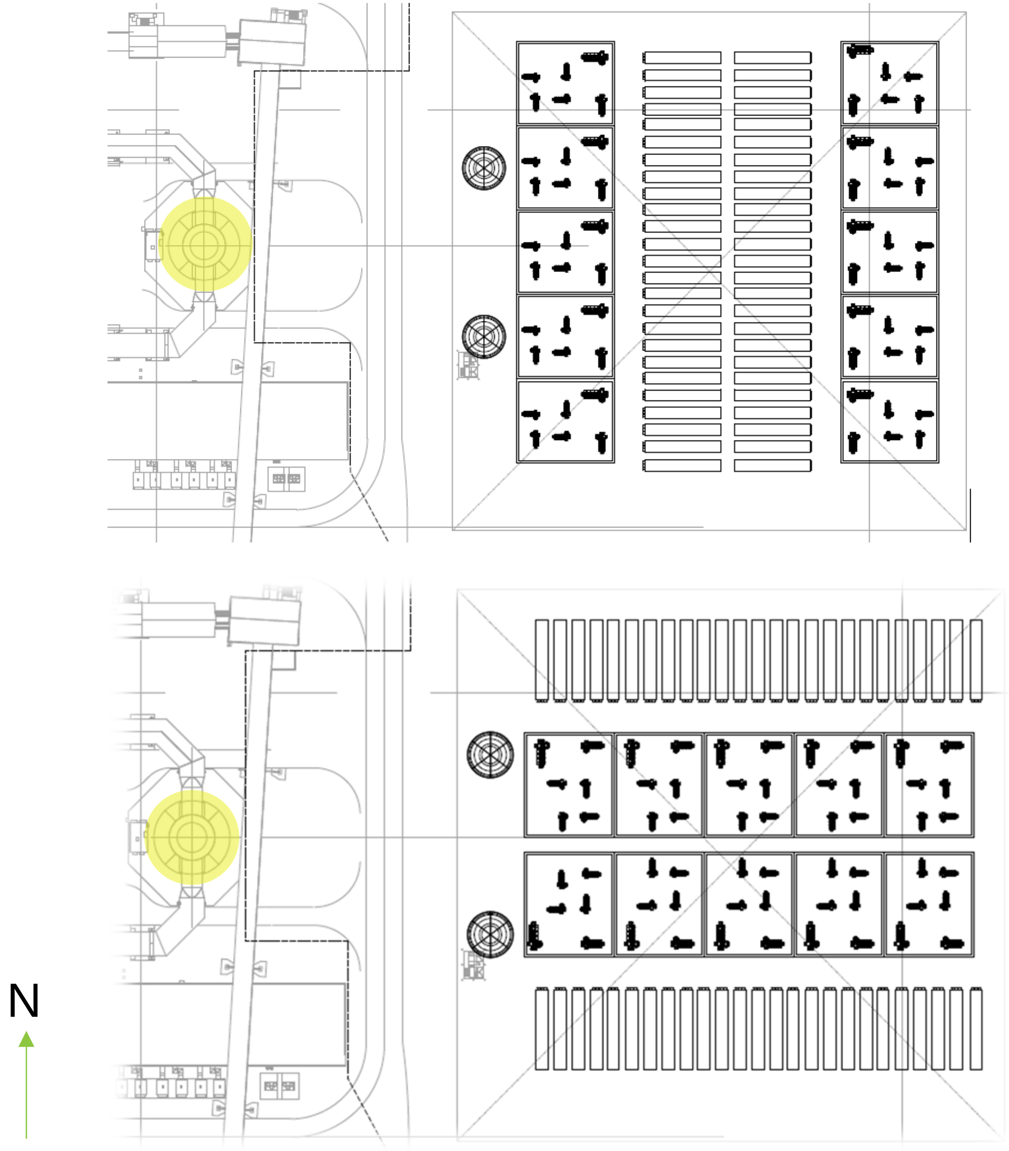
All Fans



MTR CARBON CAPTURE

Orientation and Grouping of Plant Equipment

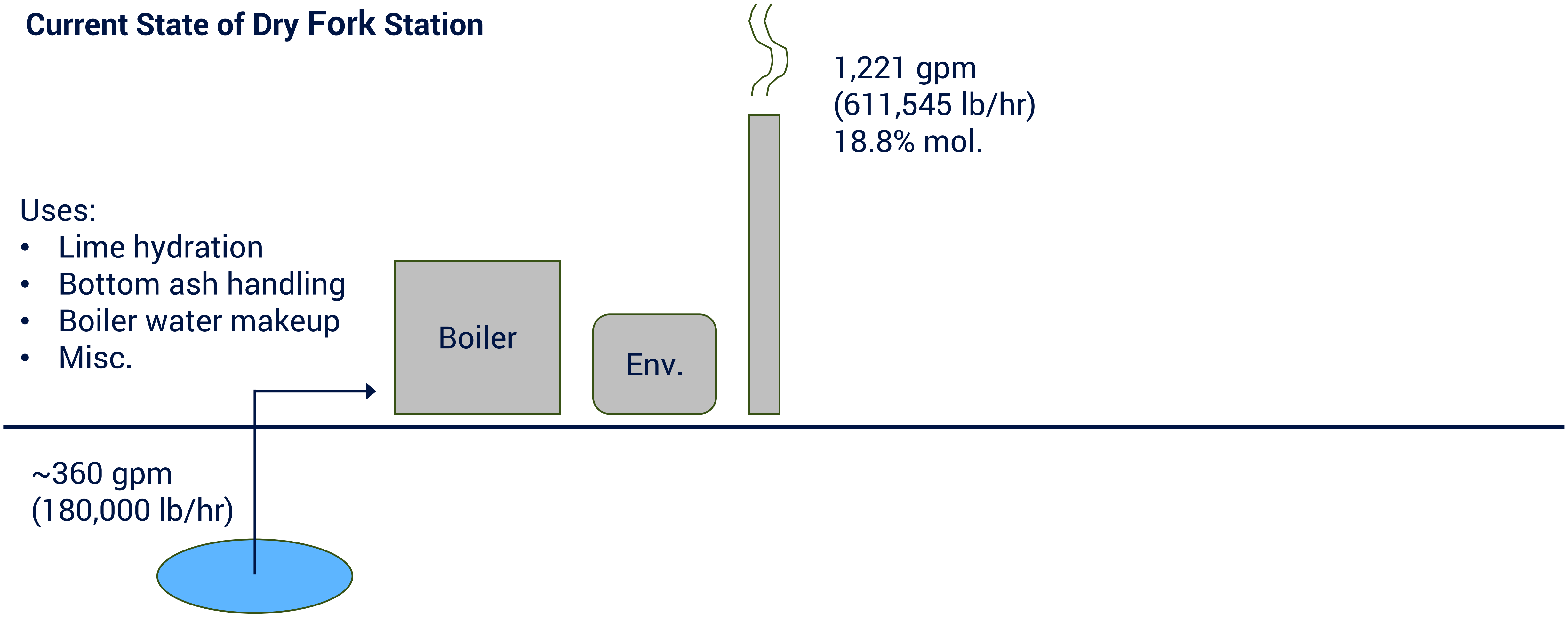
- S&L developed several layout options; variations on the layouts shown here
- East-West alignment allows for more options for direct flue gas routing to the membranes
- Centralized equipment allows for a single building enclosure & simplifies/centralizes cable and pipe routing
- Having the containers on the outside allows for ease of access to the flanged connections on both ends of the container (placing them back-to-back would increase the footprint of the membranes)



Simplified Water Balance

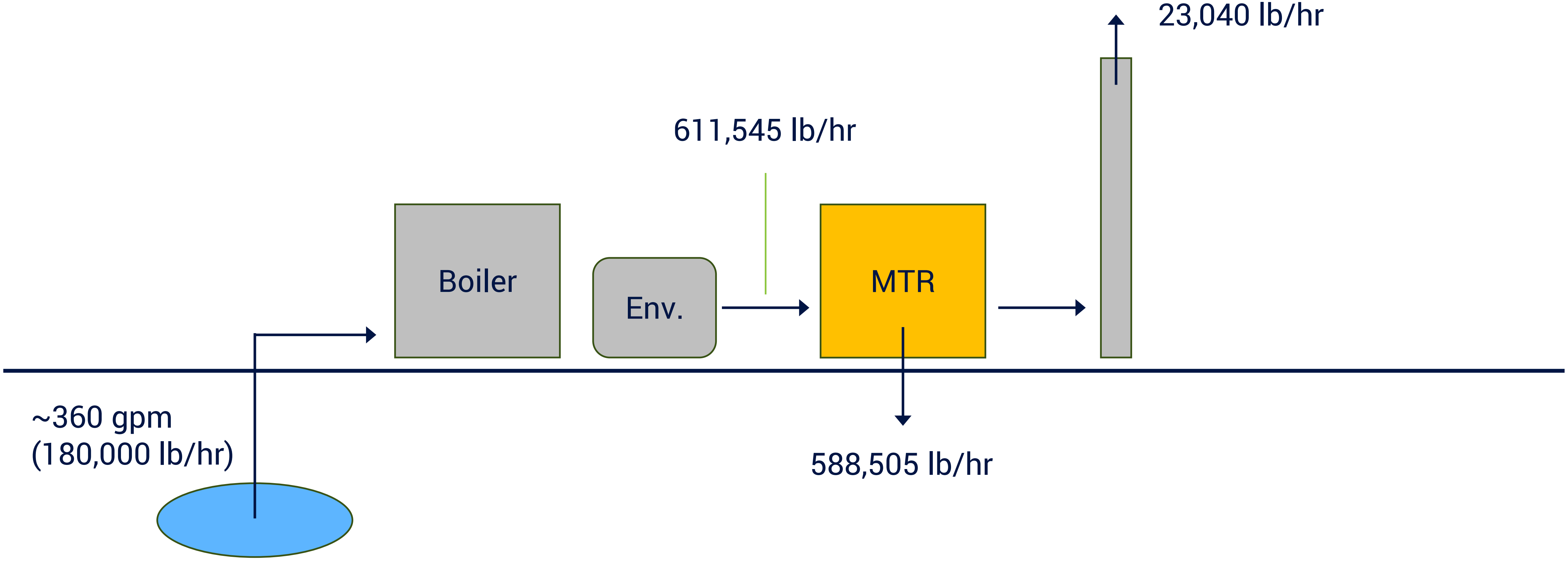
Current State of Dry Fork Station

Uses:
- Lime hydration
- Bottom ash handling
- Boiler water makeup
- Misc.



Simplified Water Balance

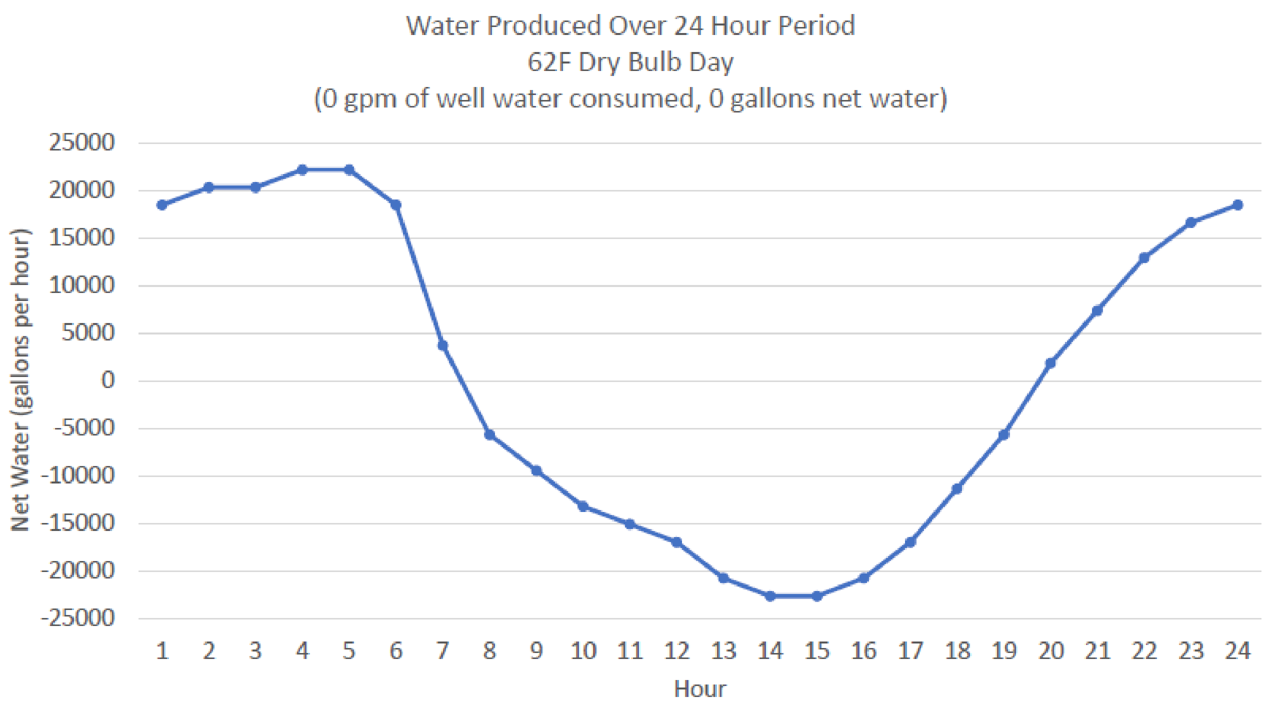
Future State of Dry Fork Station



MTR CARBON CAPTURE

Water Supply Study

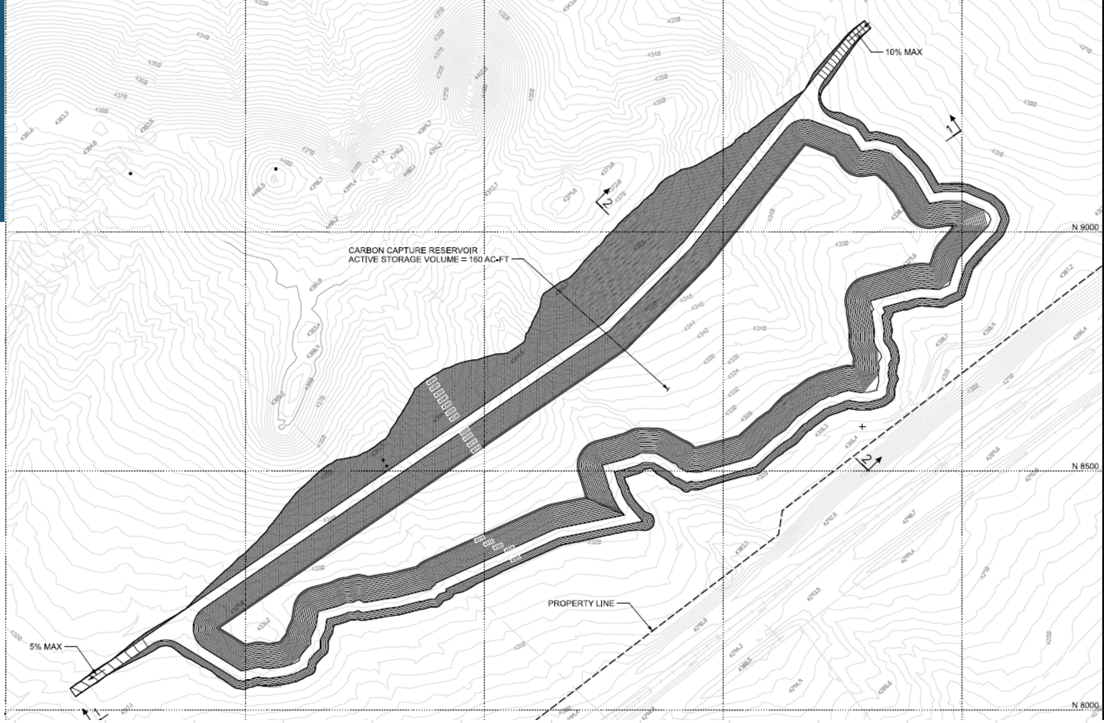
- Initial focus on meeting the well water budget (610 gpm) during warm summer months
- This informed the selection of cooling equipment; combination of WSAC and evap cooling towers (hybrid cooling scheme)
- The water demand at 88 °F (design) exceeded the water budget by ~125 gpm
- Concern raised over potential surplus during cooler months
- Models predicted the carbon capture plant to be “water neutral” at 62 °F and large surplus (1,163 gpm) at 0 °F

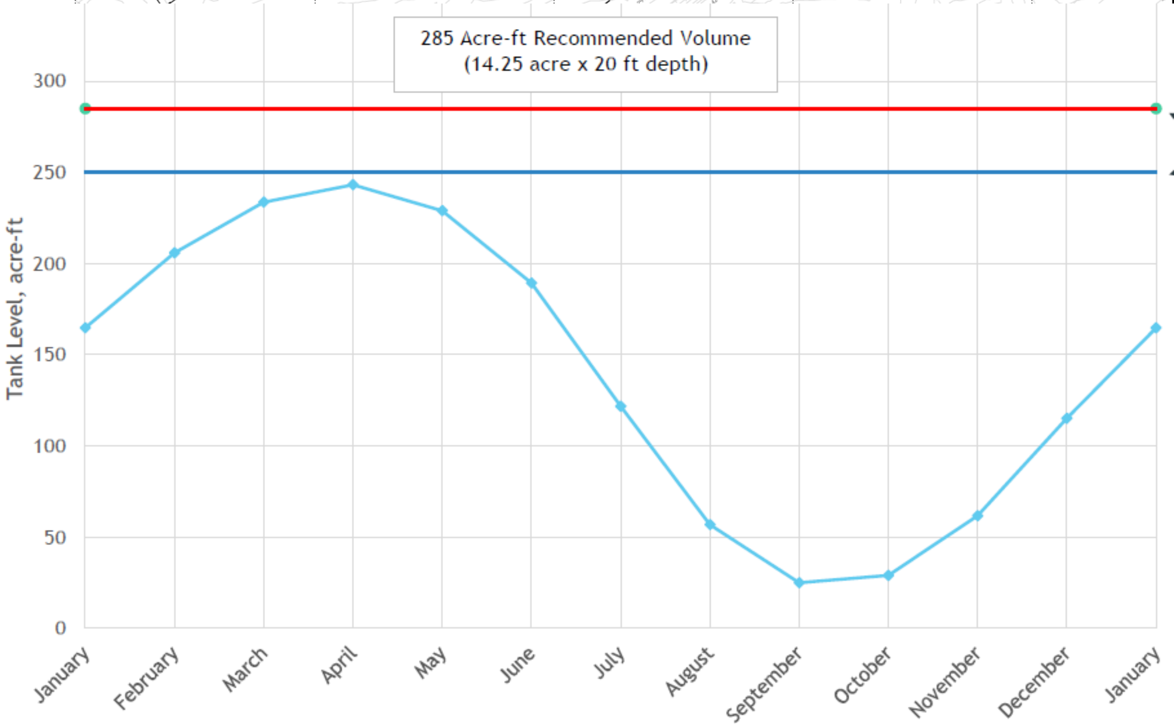


MTR CARBON CAPTURE

Reservoir Model and Sizing

- The capture plant is nearly “water neutral” on an annual basis; average of 64 gpm
- However, a large net surplus of water will be generated during the 7 colder months
- Impoundment pond design and sized at 14 acres with 285 acre-feet of storage
- S&L developed a model to calculate the surplus generated throughout each month of the year and the team examined options for other uses:
  - Off site use: coal mining industry, municipal, farm
  - Wet cooling tower + steam condenser for DFS
  - Increasing the amount of water reused within DFS (e.g. lime hydration)

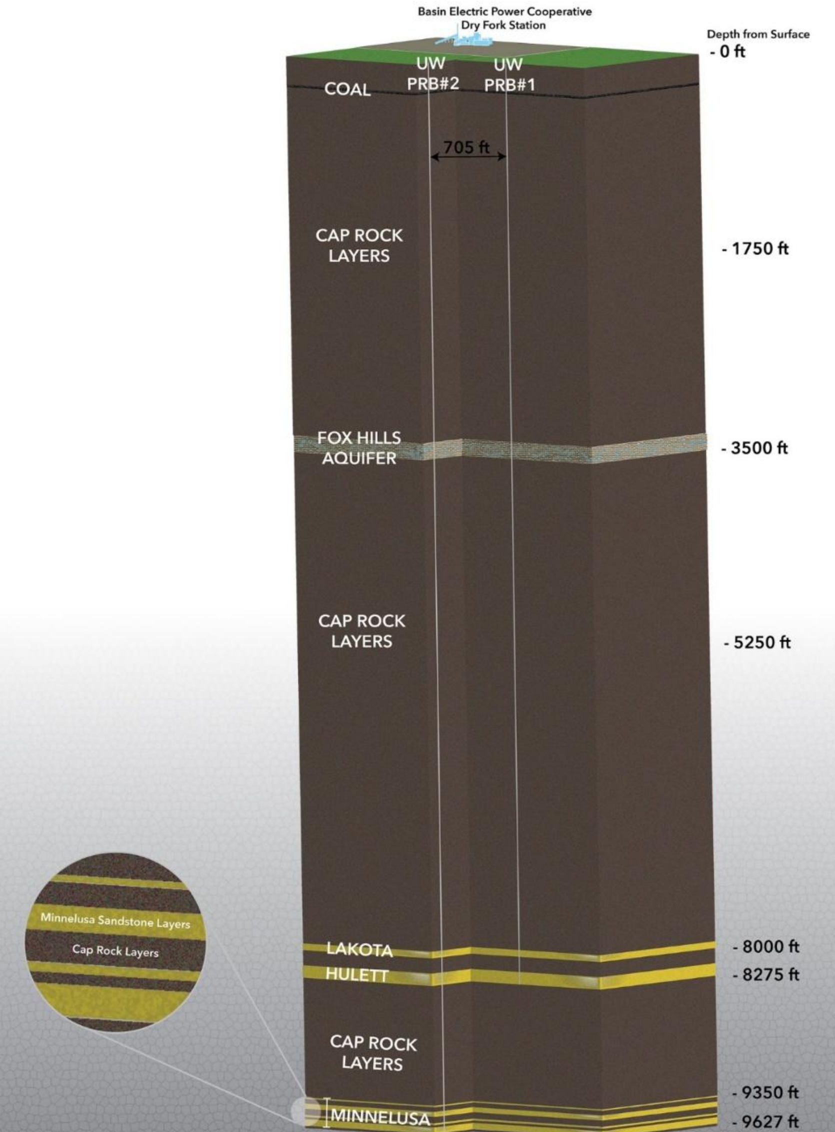


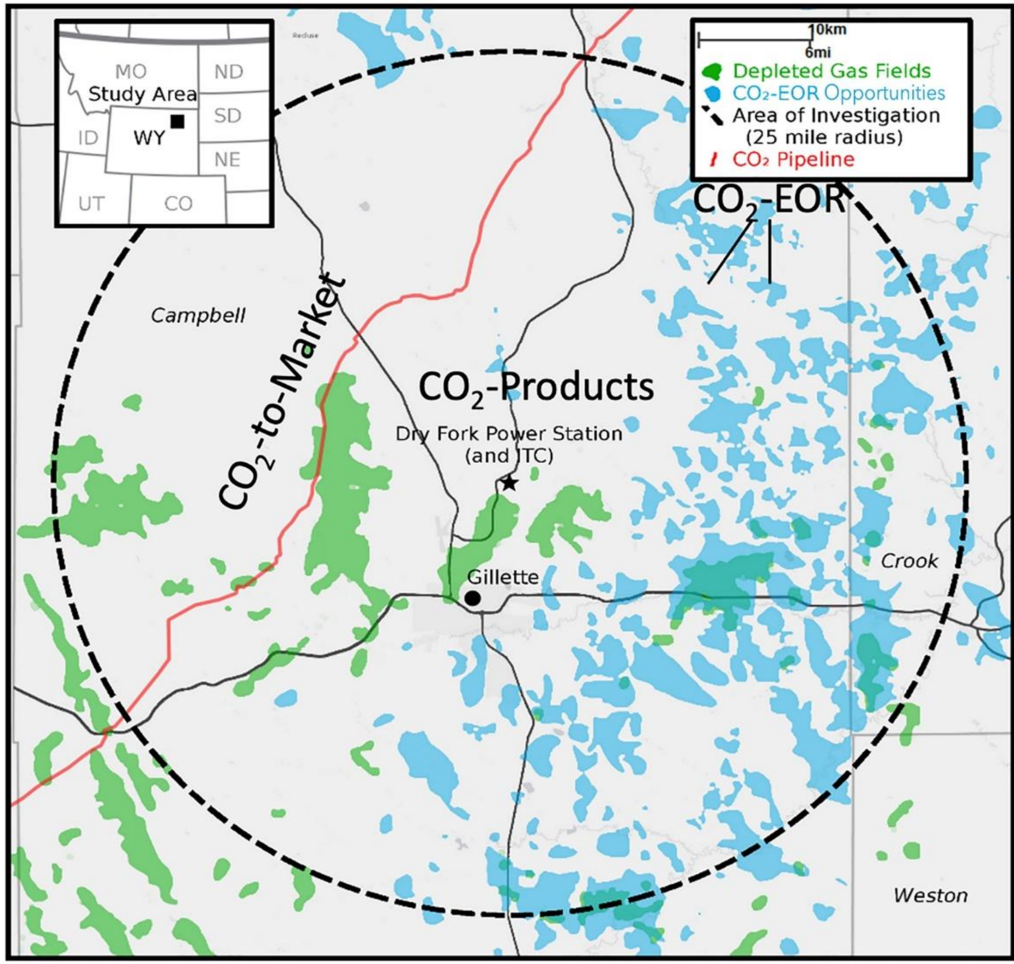


Final Design of the Capture Plant

- Two-stage Polaris™ membrane-based capture system with a CO_2 liquefaction and purification
- Two train design (2 x 50%)
- Capture rate of 70% (Basin's request)
- Flexibility to match DFS's current operational limits
- Water management achieved through the impoundment of collected waters in a new on-site reservoir
- High purity CO_2 product (>99.9%+ CO_2; 150 bar; <10 ppm O_2; bone-dry) meets DOE's QGESS CO_2 impurity requirements for EOR; Wyoming CarbonSAFE's requirements; GreenCore CO_2 pipeline

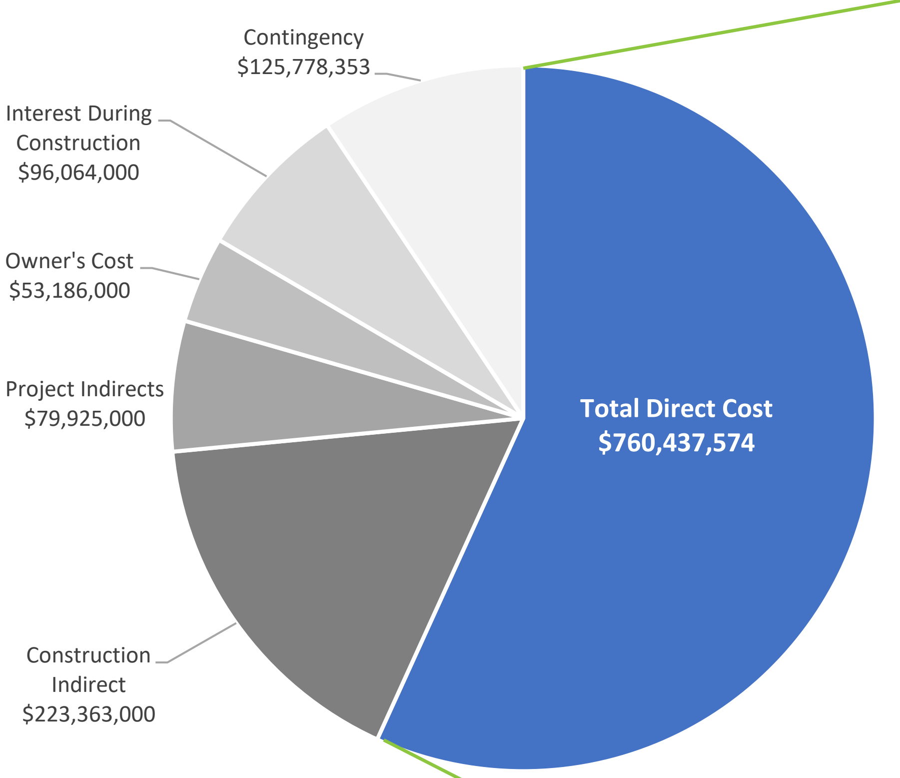
Wyoming CarbonSAFE Storage Site (FE0031891)



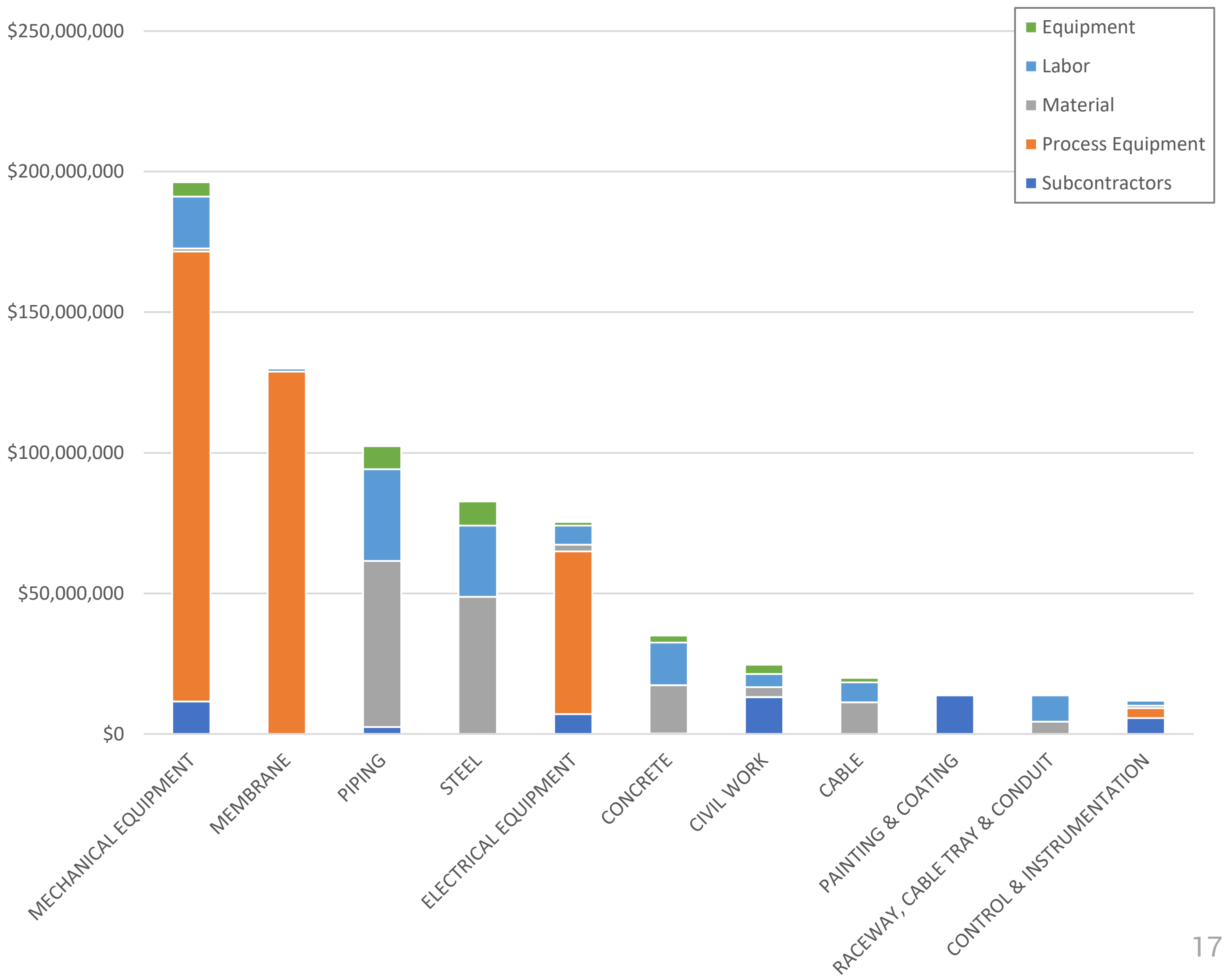


Capital Cost Summary

Total Project Cost $1.338B (2022$)



Total Direct Cost: Top 95% of Cost by Category and Type



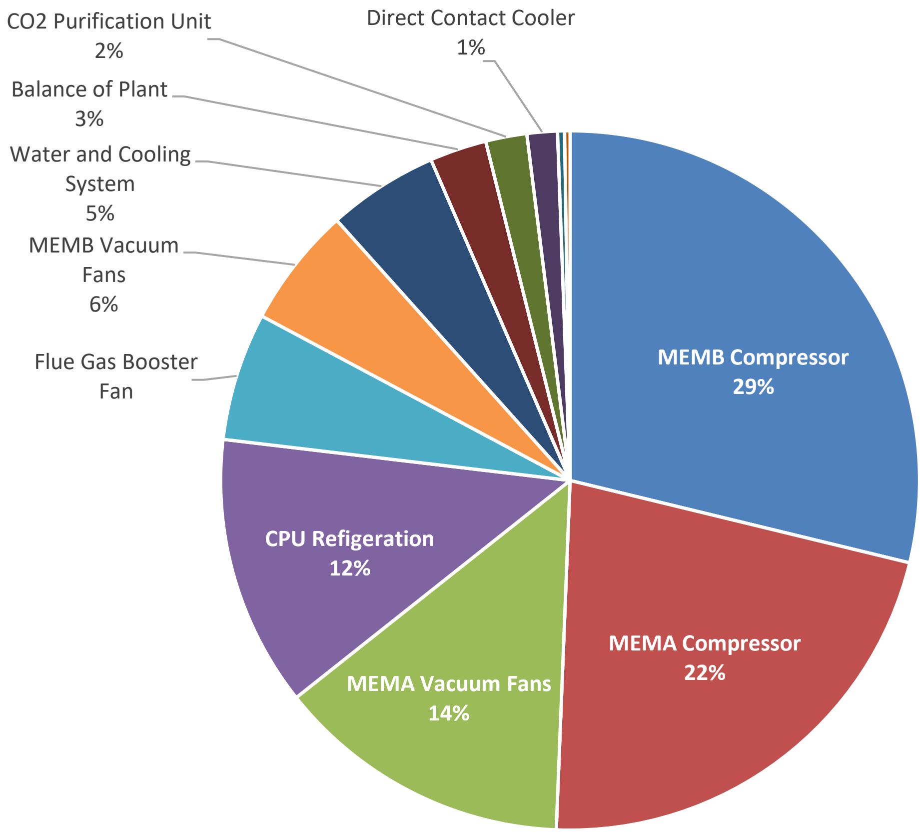
MTR CARBON CAPTURE

Excerpt from the Capital Cost Estimate

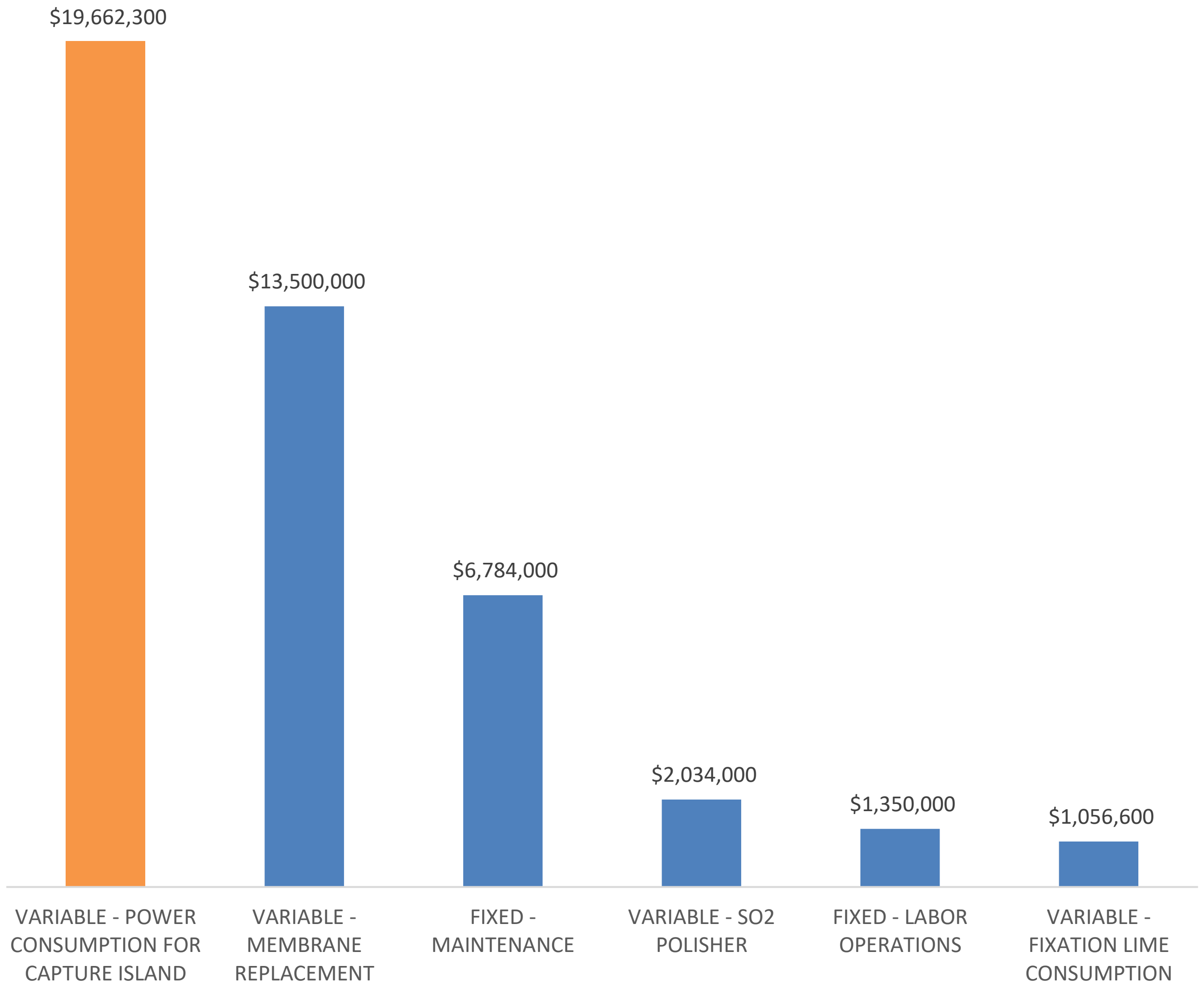
Group	Phase	Description	Notes	Quantity	Subcontract Cost	Process Equipment Cost	Material Cost	Man Hours	Labor Cost	Equip Amount	Total Cost
	42.15.33	CONDUIT, PVC									
		4 IN DIA, SCH 40 DIRECT BURIED INCLUDING FITTINGS AND MISC HARDWARE, INCLUDES EARTHWORK	RESERVOIR PUMPHOUSE	2,500.00 LF	-	-	17,875	721	39,475	11,100	68,450
		4 IN DIA, SCH 40 DIRECT BURIED INCLUDING FITTINGS AND MISC HARDWARE, INCLUDES EARTHWORK	DIRECT BURIED	250.00 LF	-	-	1,788	86	5,268	105	7,160
		6 IN DIA, SCH 40 DIRECT BURIED INCLUDING FITTINGS AND MISC HARDWARE, INCLUDES EARTHWORK	DIRECT BURIED	30.00 LF	-	-	462	14	859	17	1,338
		CONDUIT, PVC					20,384	841	46,798	11,246	78,428
	42.15.37	CONDUIT, RGS									
		3/4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	I&C CABLES	157,500.00 LF	-	-	970,515	42,145	2,567,041	50,966	3,588,522
		1 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	30,000.00 LF	-	-	274,950	9,890	602,379	11,960	889,288
		1 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	I&C CABLES	4,800.00 LF	-	-	43,992	1,582	96,381	1,914	142,286
		1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	7,100.00 LF	-	-	71,533	2,781	169,405	3,363	244,301
		1-1/2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	I&C CABLES	1,700.00 LF	-	-	17,128	666	40,562	805	58,495
		2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	8,200.00 LF	-	-	106,067	3,981	242,497	4,815	353,379
		2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	I&C CABLES	700.00 LF	-	-	9,055	340	20,701	411	30,167
		2 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	OUTDOOR LIGHTING	100.00 LF	-	-	1,294	49	2,957	59	4,310
		3 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	7,400.00 LF	-	-	134,680	5,486	334,165	6,634	475,479
		4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	6,400.00 LF	-	-	170,560	5,937	361,595	7,179	539,334
		4 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	I&C CABLES	500.00 LF	-	-	13,325	464	28,250	561	42,136
		5 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	1,500.00 LF	-	-	75,075	1,943	118,354	2,350	195,779
		6 IN DIA INCLUDING ELBOWS, UNISTRUT SUPPORTS, AND MISC HARDWARE	POWER CABLES	800.00 LF	-	-	58,240	1,534	93,423	1,855	153,518
		CONDUIT, RGS					1,946,412	76,797	4,677,712	92,871	6,716,994
	42.17.00	CONDUIT BOX									
		LOCAL JUNCTION BOXES (14" x 12" x 6")	2-12 POINT TERMINAL BLOCKS IN NEMA 4X STAINLESS STEEL ENCLOSURE	6.00 EA	-	-	7,800	55	3,361	67	11,227
		LOCAL JUNCTION BOXES (20" x 20" x 6")	4-12 POINT TERMINAL BLOCKS IN NEMA 4X STAINLESS STEEL ENCLOSURE	6.00 EA	-	-	14,040	55	3,361	67	17,467
		LOCAL JUNCTION BOXES (24" x 24" x 6")	6-12 POINT TERMINAL BLOCKS IN NEMA 4X STAINLESS STEEL ENCLOSURE	4.00 EA	-	-	12,480	37	2,240	44	14,765
		LOCAL JUNCTION BOXES (20" x 20" x 6")	POWER TERMINAL BLOCKS IN NEMA 4X STAINLESS STEEL ENCLOSURE FOR WELDING RECEPTACLES	26.00 EA	-	-	60,840	239	14,562	289	75,692
		PULL BOXES (12" W x 12" W x 12" D)	NEMA 4X STAINLESS STEEL ENCLOSURE	15.00 EA	-	-	8,775	138	8,401	167	17,343
		PULL BOXES (24"W x 24"L x 12"D)	NEMA 4X STAINLESS STEEL ENCLOSURE	15.00 EA	-	-	19,500	138	8,401	167	28,068
		CONDUIT BOX					123,435	662	40,327	801	164,562

Operating Cost Summary

Power Consumption by Unit Operation



Top 95% of Annual Operating Cost by Category



Economic Summary

Cost of Capture Summary:		Spring 2022 dollars
Capacity Factor (CF)	%	90
Annual CO_2 Production Rate @ 100% CF	tonne/yr	2,613,670
Annual CO_2 Production Rate @ Actual CF	tonne/yr	2,352,303
Total Capital Costs (including contingencies)[1]	$	1,338,753,927
Total O&M Cost	$/yr	45,622,000
Annualization Factor[2]		0.0672
Annualized Capital Cost	$/yr	89,964,264
Total Annual Costs	$/yr	135,586,264
Cost of Capture ($2022)	**$/tonne**	57.64

[1] Incorporates majority of post-COVID inflationary price increase for commodity building materials; reflects OEM process equipment quotes (pricing) as of Spring 2022.

[2] by Basin

MTR CARBON CAPTURE

DOE OCED - Phase 1 Demonstration Project
A Full-scale, Full-chain 3.1M TPY CCS Project at Dry Fork Station

- DE-0000015
- Updated Capture Plant FEED at 90% capture rate
- Pipeline FEED Study
- Storage Field Development Plan
- Permits for Class VI wells
- NEPA filing
- Lifecycle Cost Assessment

OCED Office of Clean Energy Demonstrations

BASIN ELECTRIC POWER COOPERATIVE
A Touchstone Energy Cooperative

UNIVERSITY OF WYOMING
School of Energy Resources

WYOMING ENERGY AUTHORITY

Sargent & Lundy

Kiewit

MTR CARBON CAPTURE

TRIMERIC CORPORATION

EERC
Energy & Environmental Research Center
Putting Research into Practice

Large Pilot at the Wyoming ITC - 150 TPD / 55,000 TPY

MTR CARBON CAPTURE

Questions?

MTR CARBON CAPTURE

Session 2: Transport Costs

2.1: Transport Cost

U.S. Eastern Seaboard Transport and Storage Study

Summary of CO_2 Transport Costs

Andrew Bean
Technical Leader I

Robert Trautz
Senior Technical Executive

8th CCS Cost Network Workshop – IEAGHG
March 5, 2025

Study Overview

Background

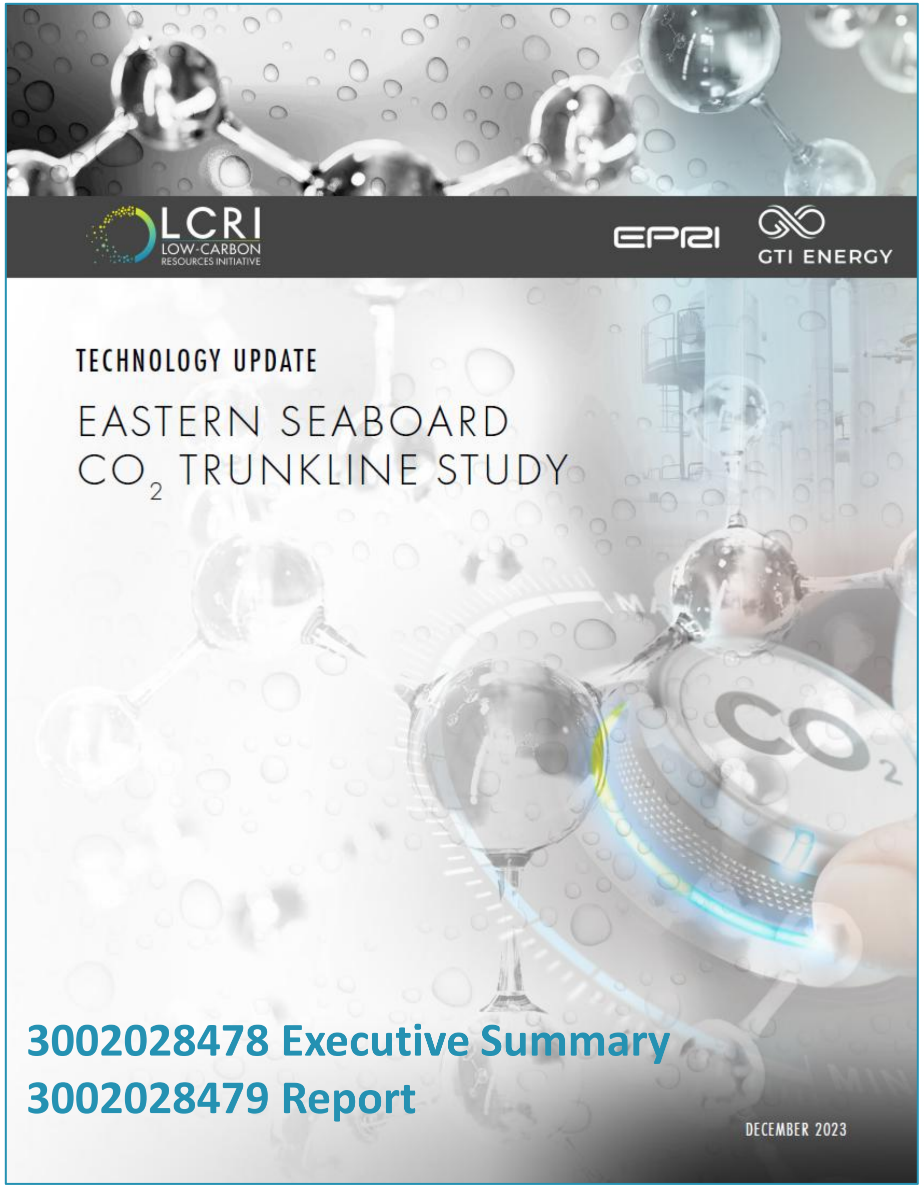
- The Eastern Seaboard faces unique decarbonization challenges:
  - High CO_2 emissions, and
  - Poor onshore storage options.

Objective

- The study illustrates how CCS infrastructure could be deployed to support regional decarbonization
- Provides high-level costs for CCS deployment along the Eastern Seaboard
- Illustrates cost patterns/trends

Method

- Four models were used to screen the cost of integrated capture, transport, and storage for the region:
  - ➢ CO_2 National Capture Opportunity and Readiness Database (CO_2NCORD) - CO_2 capture cost model
  - ➢ *CostMAP*^{PRO} - Pipeline and shipping cost model
  - ➢ *SCO2T*^{PRO} - Storage cost and capacities model
  - ➢ Integrated costs for capture, transport, and storage were calculated using *SimCCS*^{PRO}



Integrated costs were calculated for seventeen CCS scenarios

OVERVIEW: Sources & Sinks

Source Characterization using CO_2NCORD

Step 1: Identify and Classify Sources of Emissions

CO_2 National Capture TheOpportunity and Readiness Database (CO_2NCORD) developed by Carbon Solutions provides each facility by industry, their emissions profile, equipment, etc.

1) Define the project Area of Interest (AOI) - Eastern Seaboard from southern Florida to northern Manhattan (NY) and southern Pennsylvania
2) Remove small facilities (universities, airports, waste landfills etc.).

Step 2: Estimate Facility-level Capturable Emissions

CO_2NCORD further breaks each facility's emissions into unique capturable "streams"

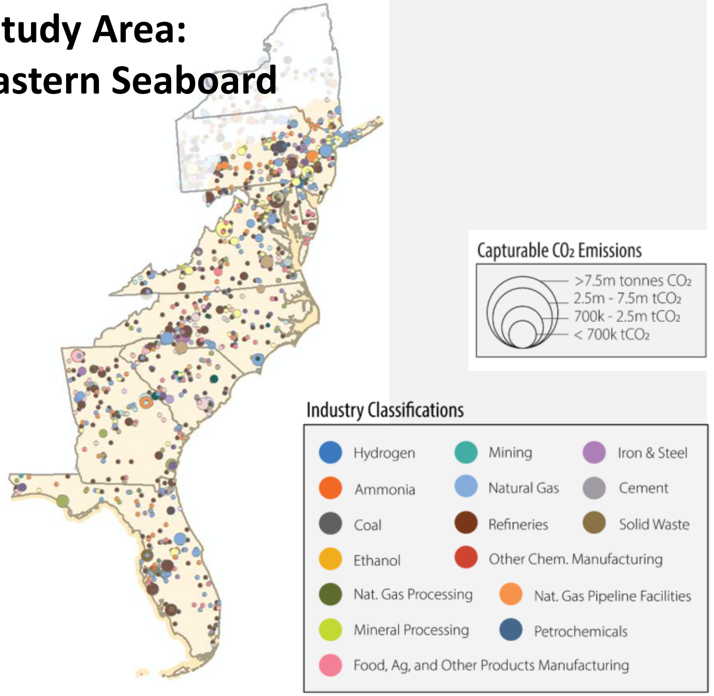
1) Each facility's capture streams are isolated point sources (may represent a specific stage in the facility's process, i.e., rotary kiln, basic oxygen furnace, etc.) – each with its own volumes/costs.

2) Only streams with minimum 45Q emissions were included in the final analysis

Step 3: Estimate Capture Costs by Stream

Capture costs were derived from the literature for individual process streams

Study Area: U.S. Eastern Seaboard

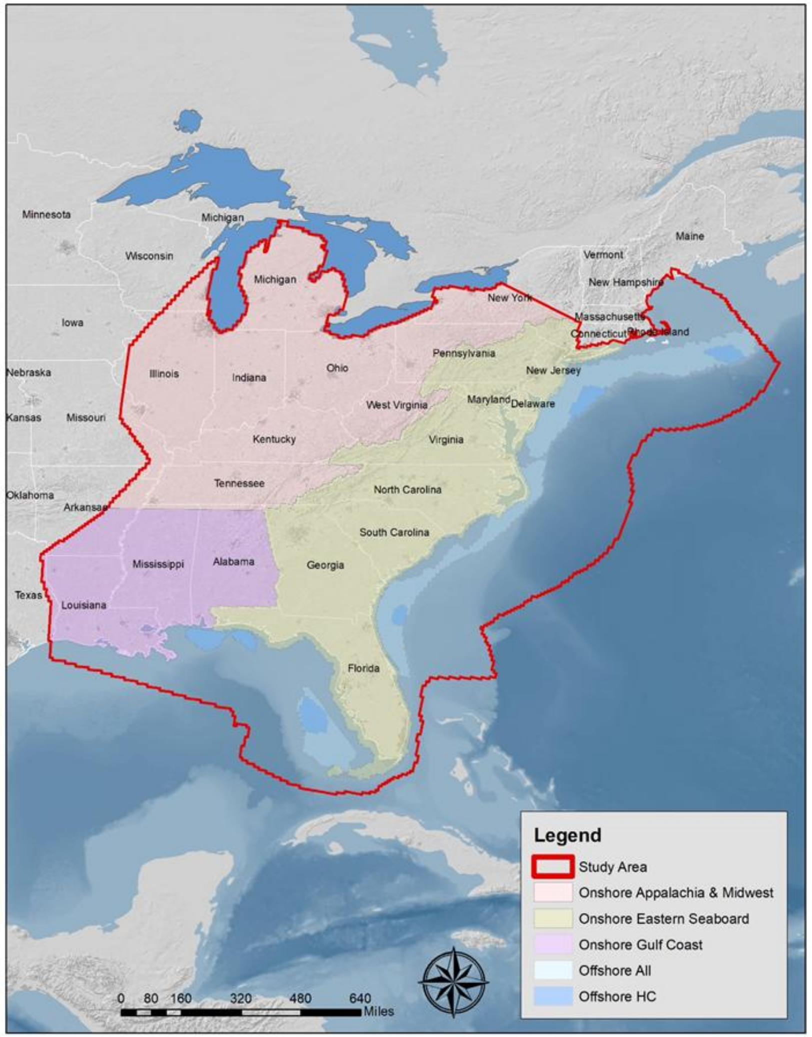


Capture Summary

- Over 276 $MtCO_2$/yr are available for capture from EGU and 88 $MtCO_2$/yr from industrial facilities within the Eastern Seaboard region
- Gas- and coal-fired power plants are the only sources with capturable emissions at or above 1 $MtCO_2$ on-average per stream
- At ≤ $50/$tCO_2$, coal-fired power plants offer the largest opportunity for capturing lower-cost, higher-purity CO_2 streams
- At $50.01-$60/tCO_2, biomass power plants provide good capture opportunities
- These sources could meet breakeven costs by capturing 45Q tax credits if transportation and storage costs are below $25/$tCO_2$
- At $60.01-70/$tCO_2$, gas-fired power plants and pulp & paper mills present opportunities for large-scale capture
  - Not all NGCC plants will present attractive economies of scale due to smaller size

Storage Characterization – Capacities, Costs using *SCO_2T^{PRO}*

- Storage properties were modeled for locations across the study area using *SCO_2T^{PRO}*
- Storage properties include rock permeability and porosity, which govern how quickly the CO_2 can be injected and how much CO_2 can be stored
- Four large geographic regions and one subregion were modeled at a 10 x 10 km resolution
  - Onshore Eastern Seaboard (olive green)
  - Onshore Eastern Gulf Coast (light purple)
  - Onshore Appalachian Basin, Illinois Basin, and Michigan Basin (pink)
  - Offshore East Coast and Eastern Gulf of Mexico (light blue)
  - Offshore high certainty areas (blue) sub region

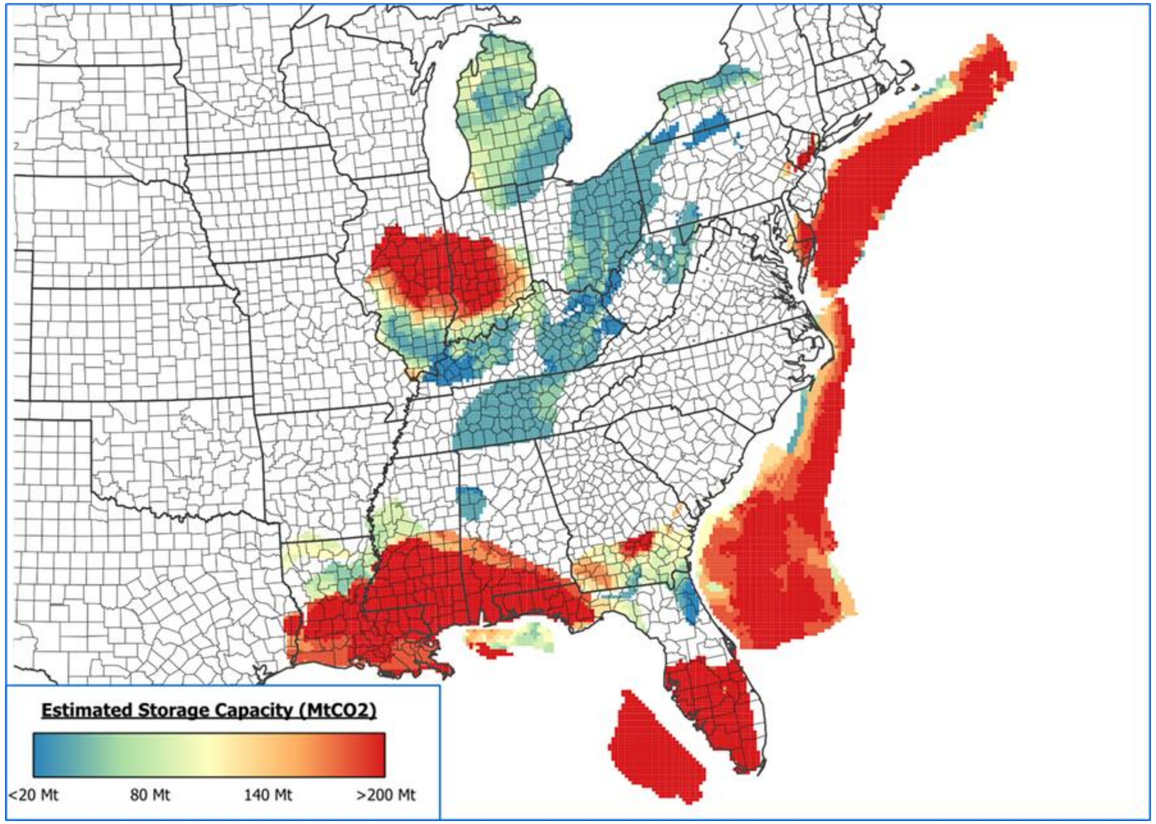


Storage regions included in the study are outlined in red

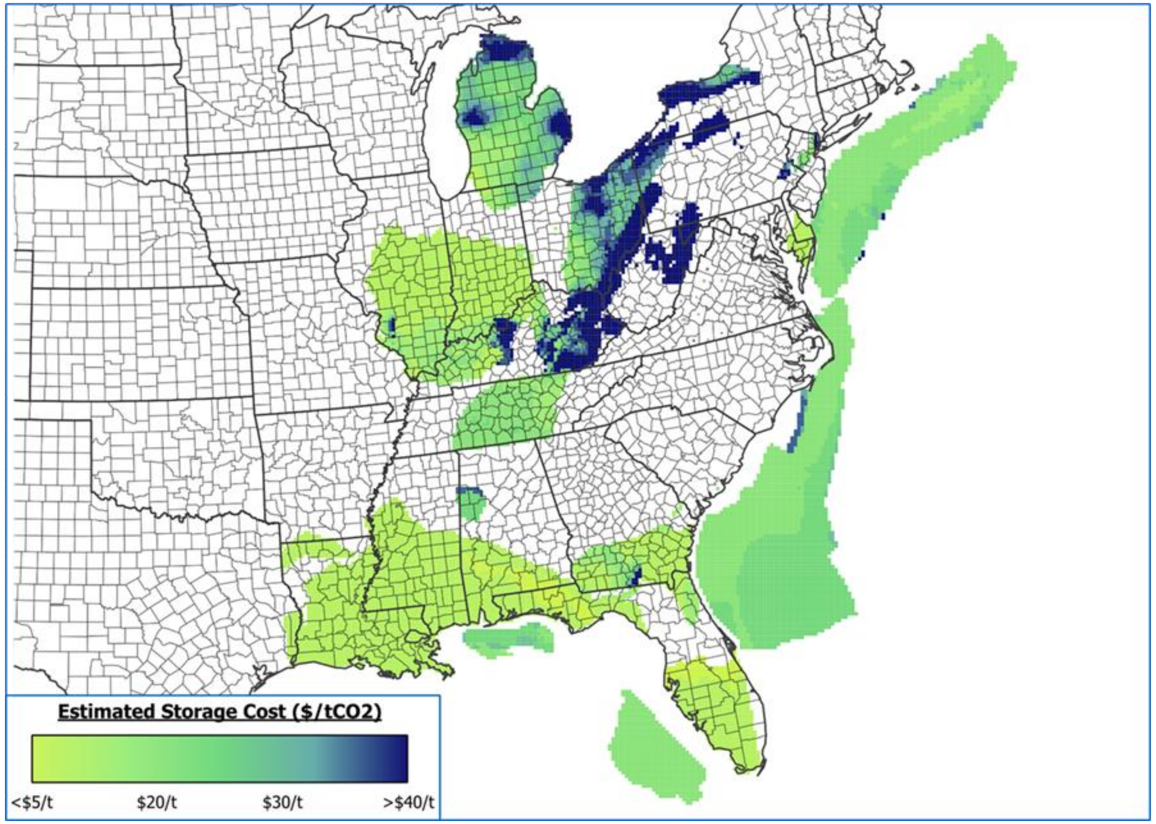
Estimated Storage Capacities and Costs

LCRI LOW-CARBON RESOURCES INITIATIVE

Storage capacity



Storage costs

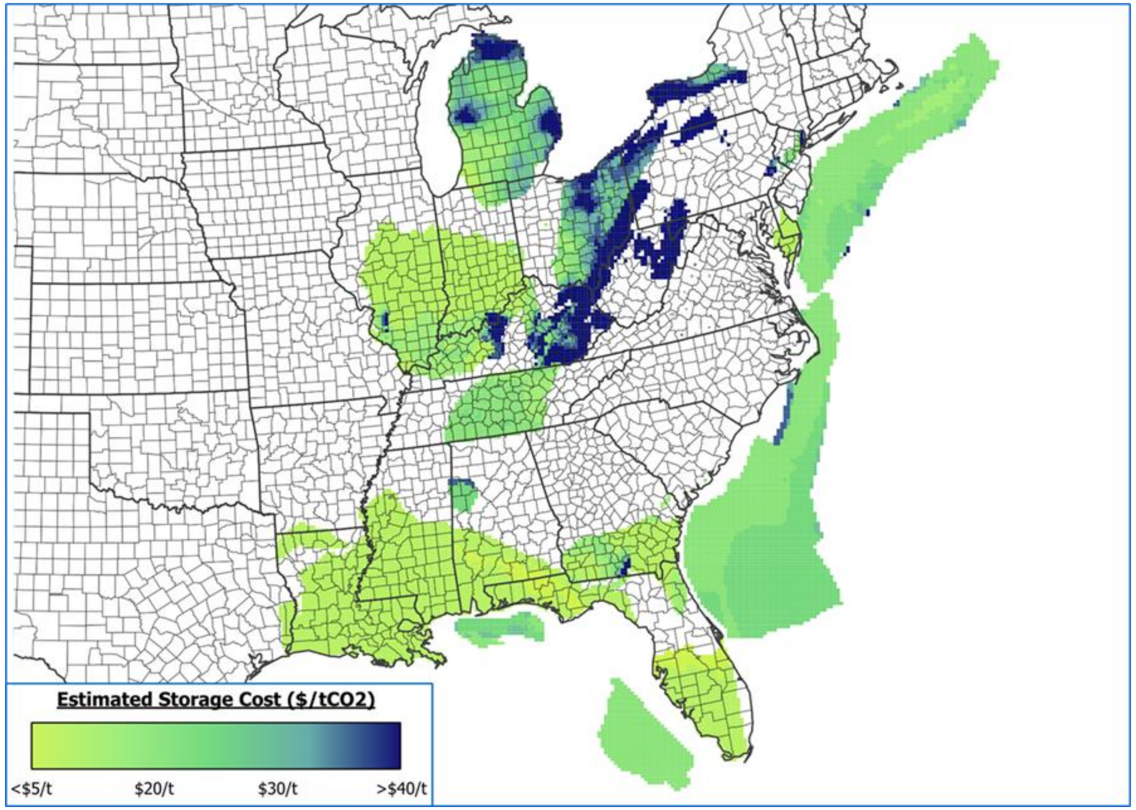


- Notice the lack of onshore storage along the entire Eastern Seaboard region
- Although offshore storage potential is shown as being high, the uncertainty is large because there are few offshore wells resulting in sparse geologic data

EPRI GTI ENERGY

Storage Summary

- Onshore Eastern Seaboard reservoirs are geographically restricted to a few small regions
- Estimated cumulative onshore storage capacity is >500 $GtCO_2$
  - 90% of this capacity is in Florida and south Georgia
  - Over 450 GtCO2 of this storage is modeled at <\$10/tCO_2
- Offshore storage capacity along the Eastern Seaboard could be immense, but costs are marginal, and capacities are highly uncertain due to the lack of offshore wells and geologic data
  - Offshore costs are ~4x higher than onshore reservoirs with similar reservoir properties and modeled capacities
  - Multiple scenarios were modeled to account for the high degree of uncertainty due to sparse data coverage. Exact geographic extent and total cumulative capacity vary dramatically by scenario
- Onshore Gulf of Mexico and Midwest have consistently high capacities and attractive storage costs
- Onshore Appalachian region is consistently poor, lower quality, and higher cost



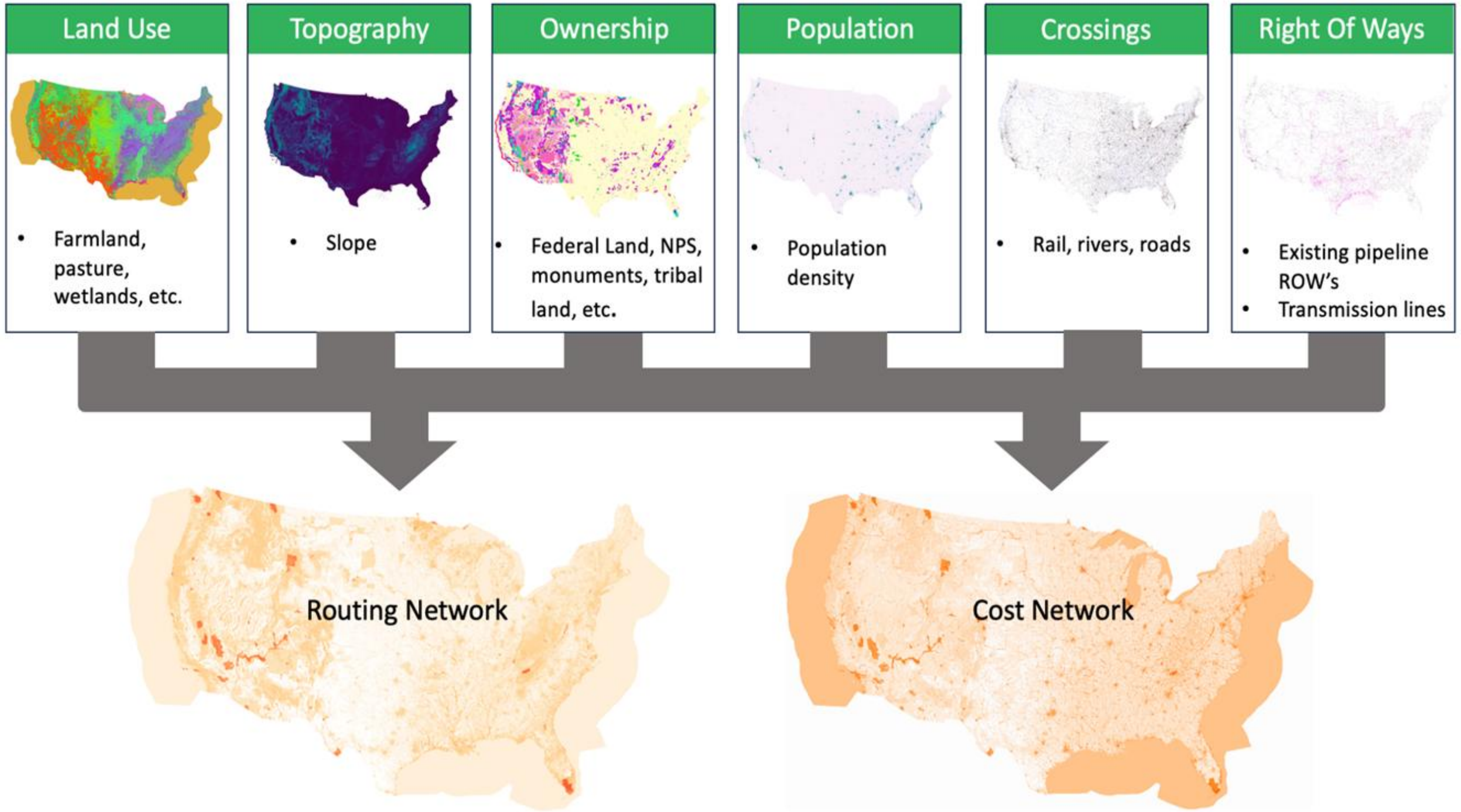
Estimated storage costs, \$/tCO_2

OVERVIEW: CO_2 Pipeline and Barging

Pipeline Transport using CostMAP^{PRO}

Geospatial data fusion

- **PEOPLE:** Population, demo-graphics, community, environ-mental justice, property values.
- **LAND:** Land cover, land use, fed/state/private, ownership.
- **CORRIDORS:** Pipelines, roads, transmission.
- **BARRIERS:** Roads, rivers, rail.
- **CUSTOM:** Any GIS layer.

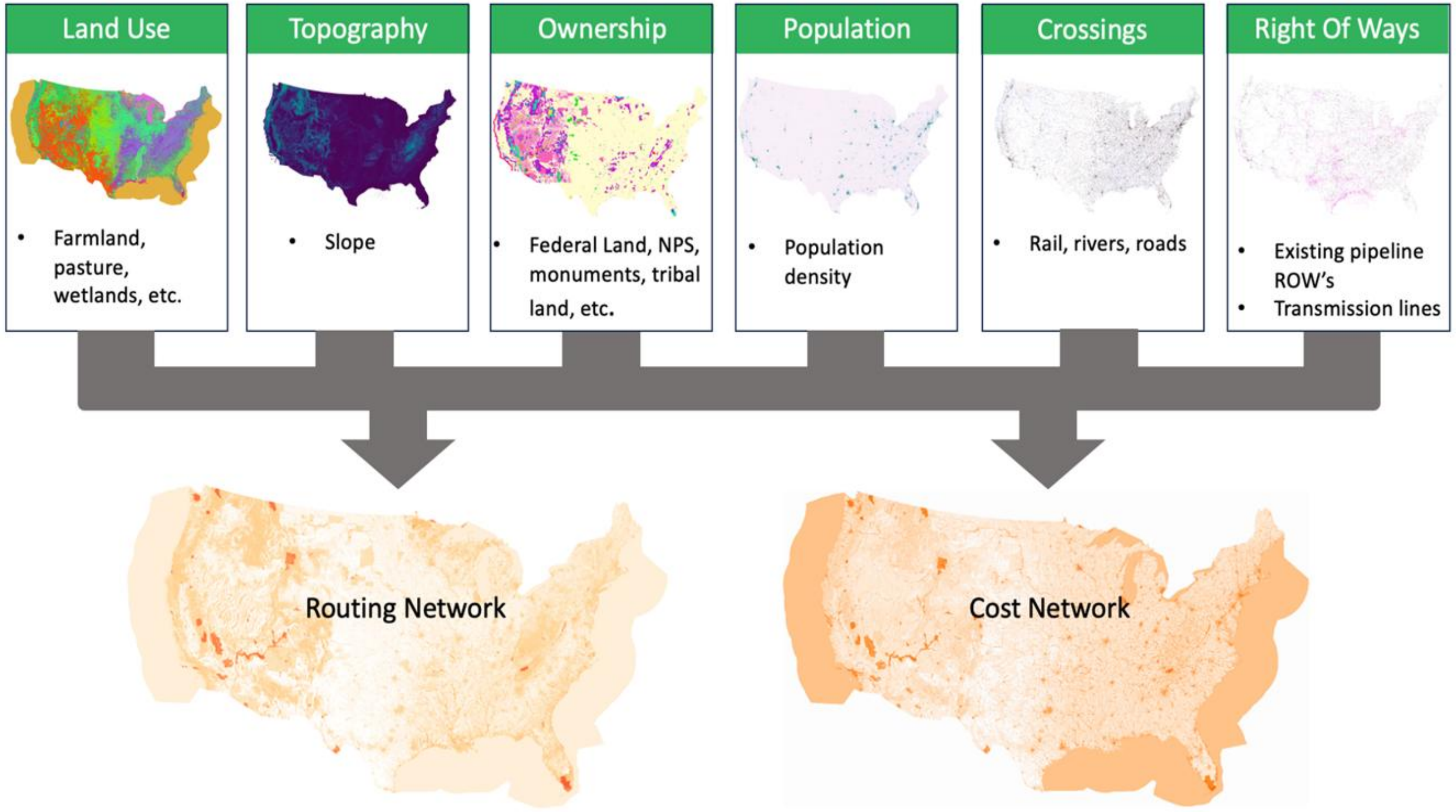


SimCCS^{PRO} uses the cost and routing surfaces to determine the lowest cost pipeline route

Pipeline Transport using CostMAP^{PRO}

Weighting flexibility

- Land Cover (33 categories)
- Government land (61 categories)
- Population density (9 categories)
- Slope (8 categories)
- Pipelines (10 categories)
- Transmission lines (8 categories)
- Rail (5 categories)
- Rivers (4 categories)
- Roads (9 categories)
- Additional layers as necessary (Justice40 data, for example)



SimCCS^{PRO} uses the cost and routing surfaces to determine the lowest cost pipeline route

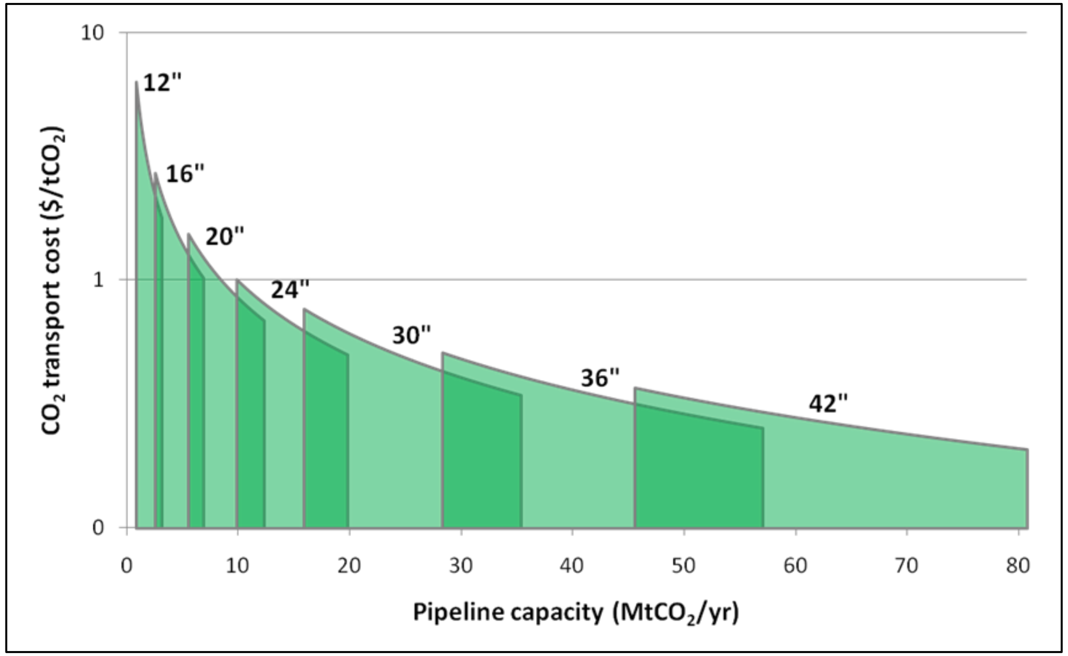
Pipeline Cost Modeling

Costs Based on NETL's Pipeline Cost tool

- CO2_T_COM: Determine capacity-specific, per-kilometer pipeline costs.
  - Covers beginning-to-end of pipeline, everything in between
  - Assumes liquid CO2, booster pumps
  - User specifies average annual mass flow rate, capacity factor, pipeline length, elevation change, number of operating years, financial variables
  - Output: CAPEX and OPEX

Pipeline Scaling

- SimCCS solves for the pipeline capacity needed
- Pipelines costs are then scaled to the appropriate diameter
- We use a linear approximation of NETL's cost model



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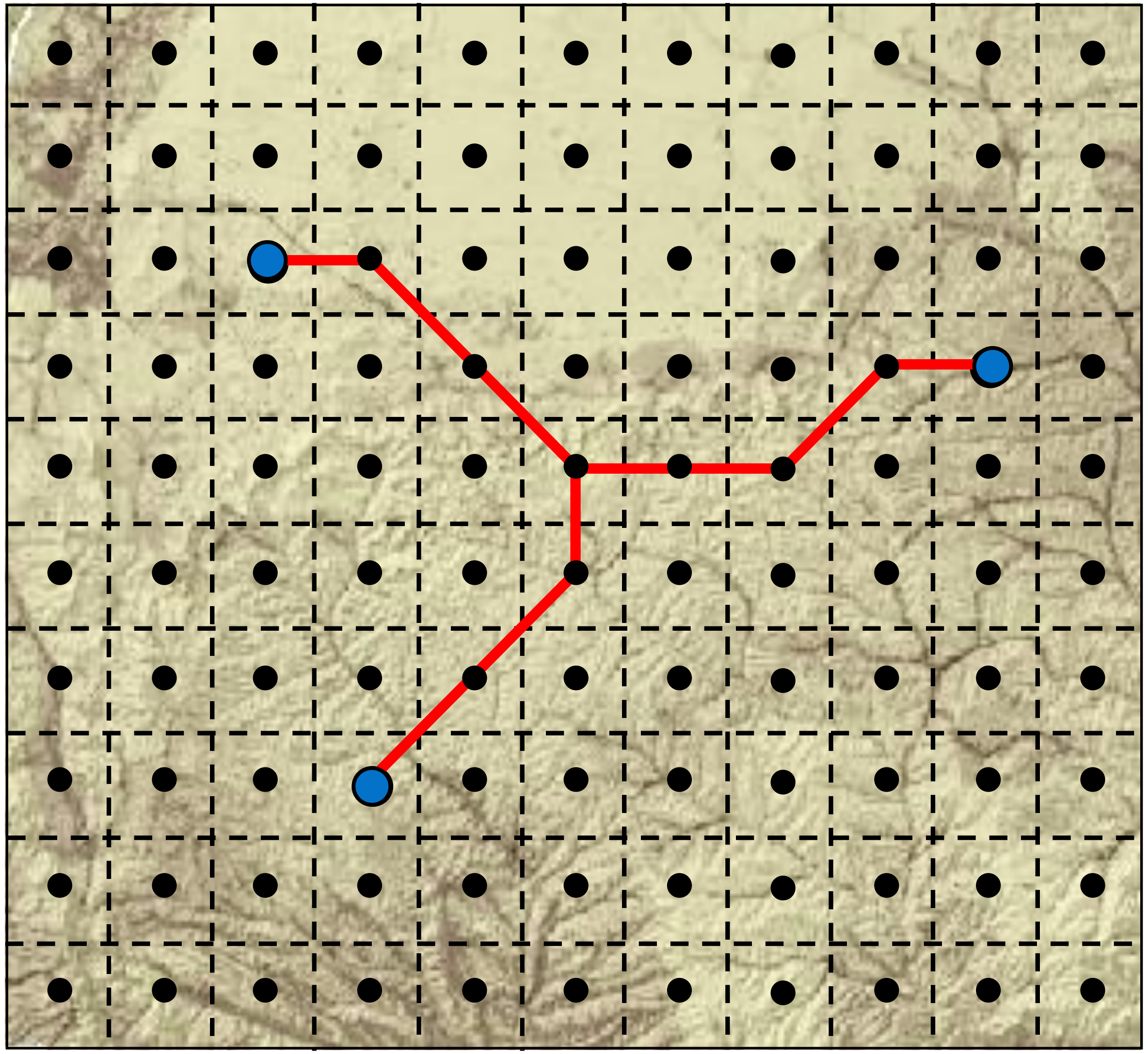
CostMAP^{PRO} Methodology



Workflow

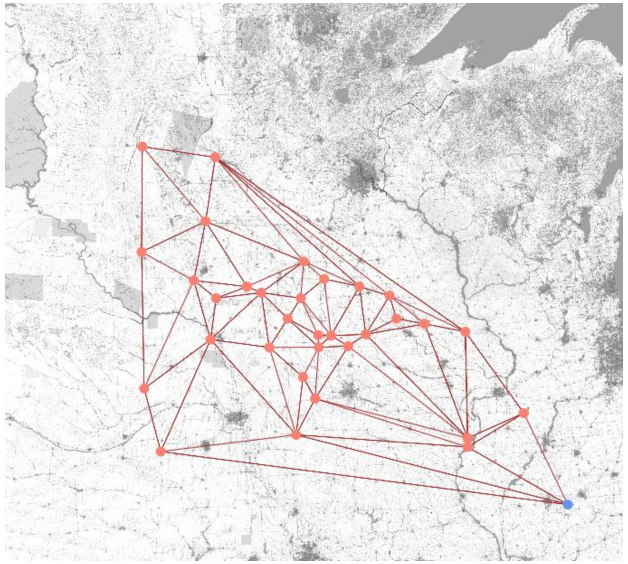
- Overlay grid on region.
- Increase/decrease NETL's cost estimates between adjacent cells using region-specific data.
- Generate grid-level resolution routing data structure.
  - Resolution ranges from 90- 720 m
- Use SimCCS^{PRO} to calculate optimal pipeline routes.

CostMAP^{PRO} Methodology

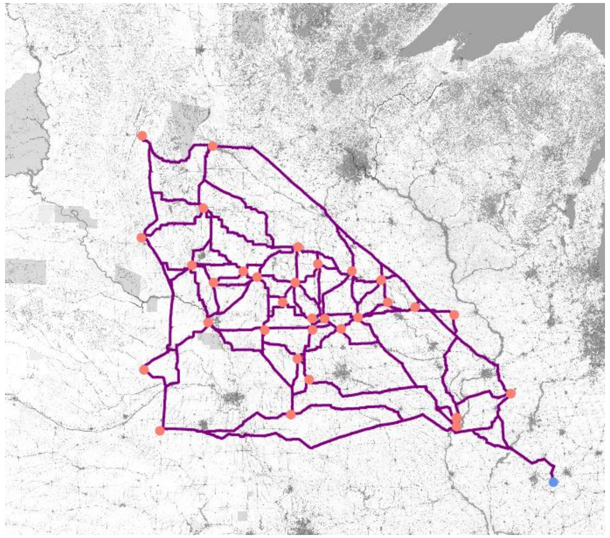
Process Steps

1. Generate the routing and cost networks
2. Generate Delaunay Triangulation
3. Use Dijkstra (1959)[2] algorithm to determine least-cost paths between all nodes
4. Raster-based paths are used to create vector arcs with associate costs
5. Superfluous arcs are removed from the network
6. The vector network is refined to be more concise and manageable for use in SimCCS
7. SimCCS solves for optimal cost

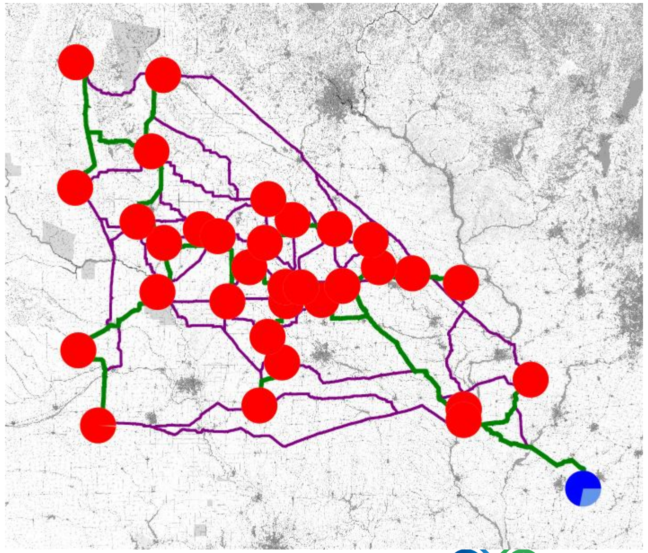
Generate Delaunay Triangulation



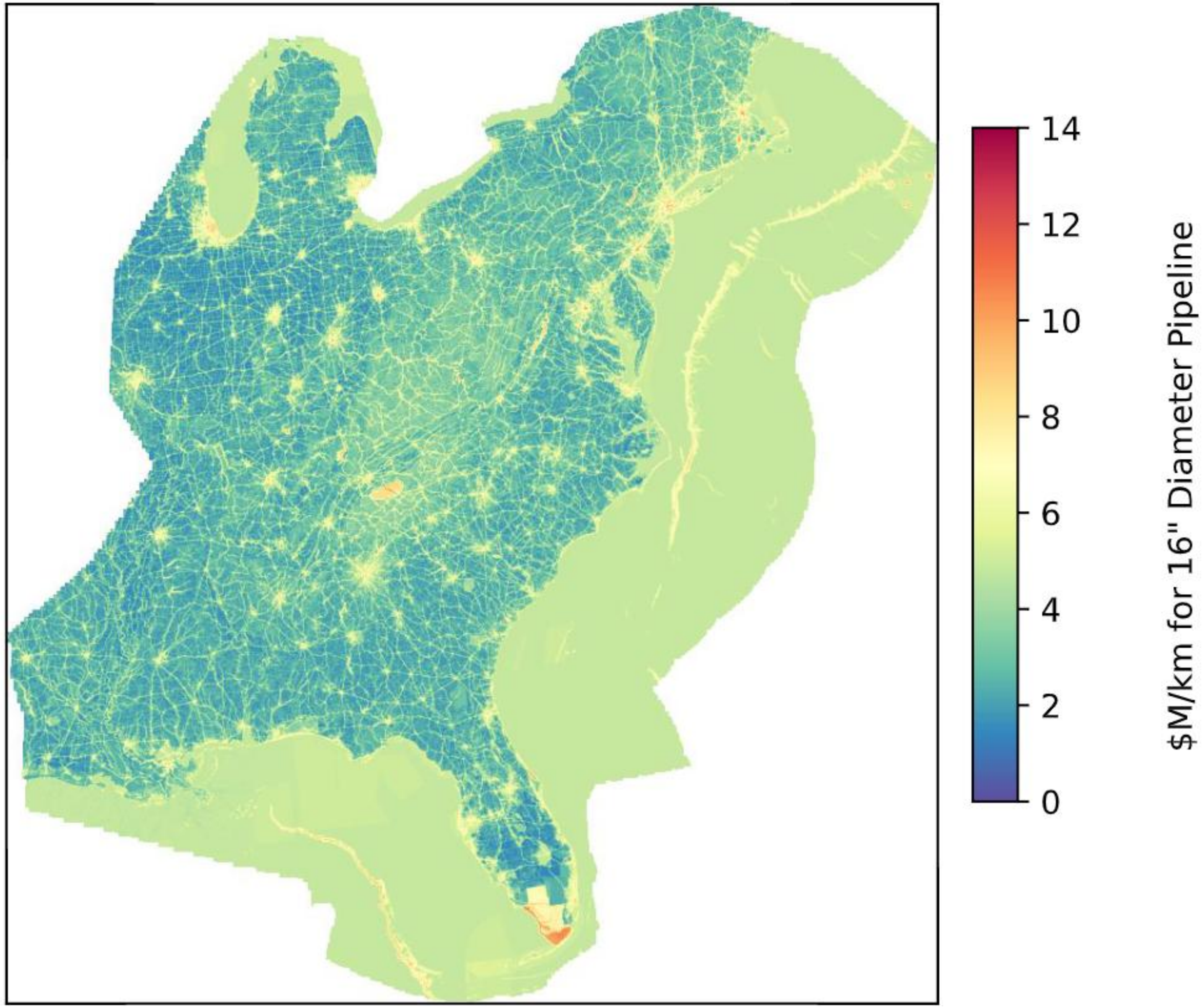
Generate Candidate Network



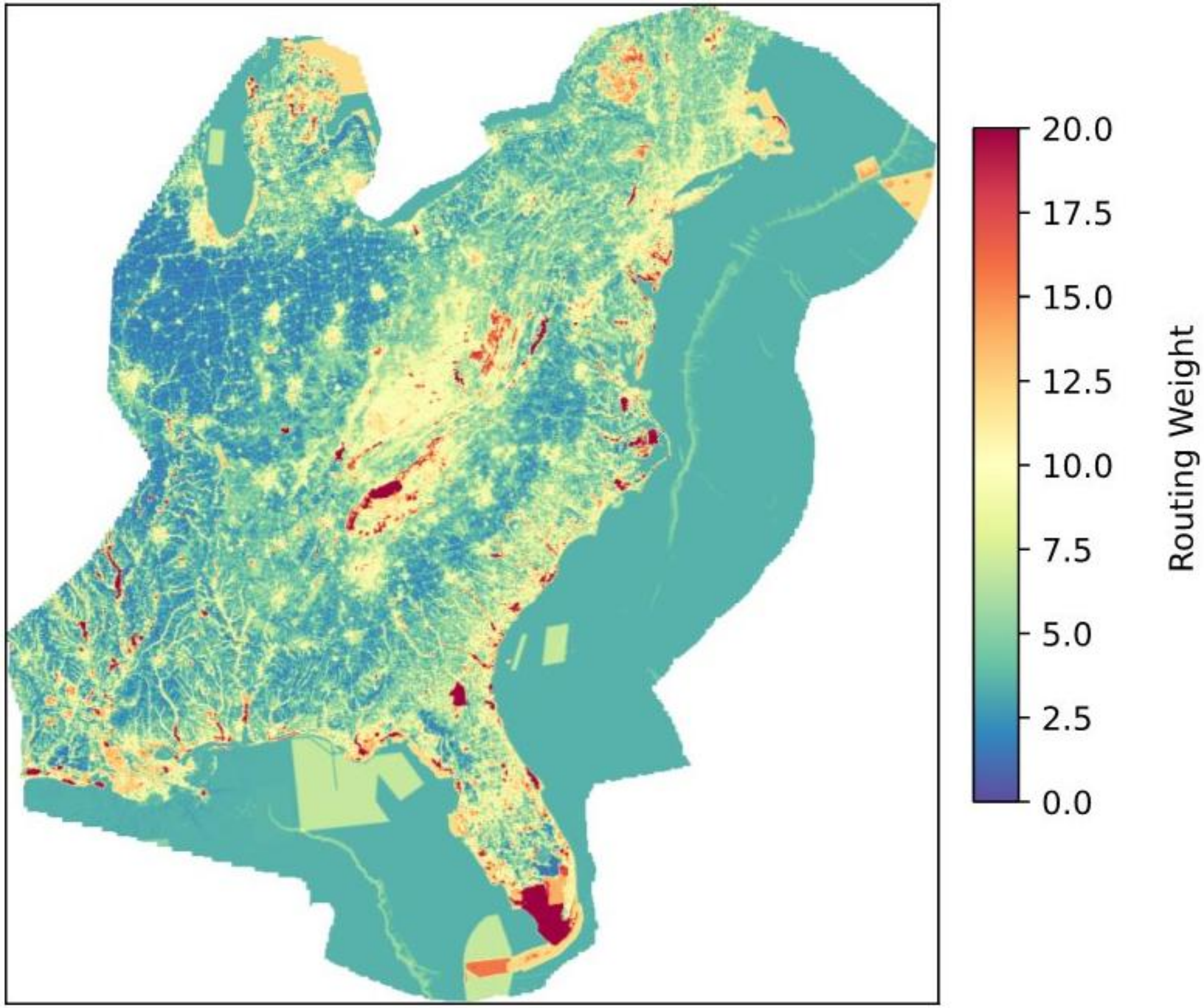
Solve for Optimal Cost & Refine Network



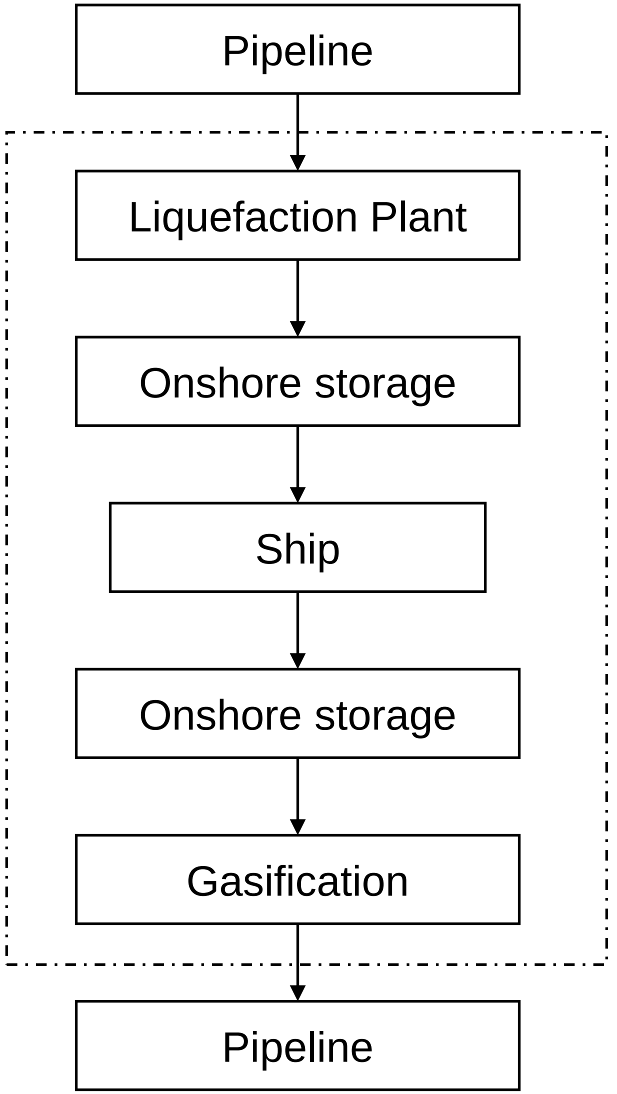
Resulting CO_2 Pipeline Cost Surface

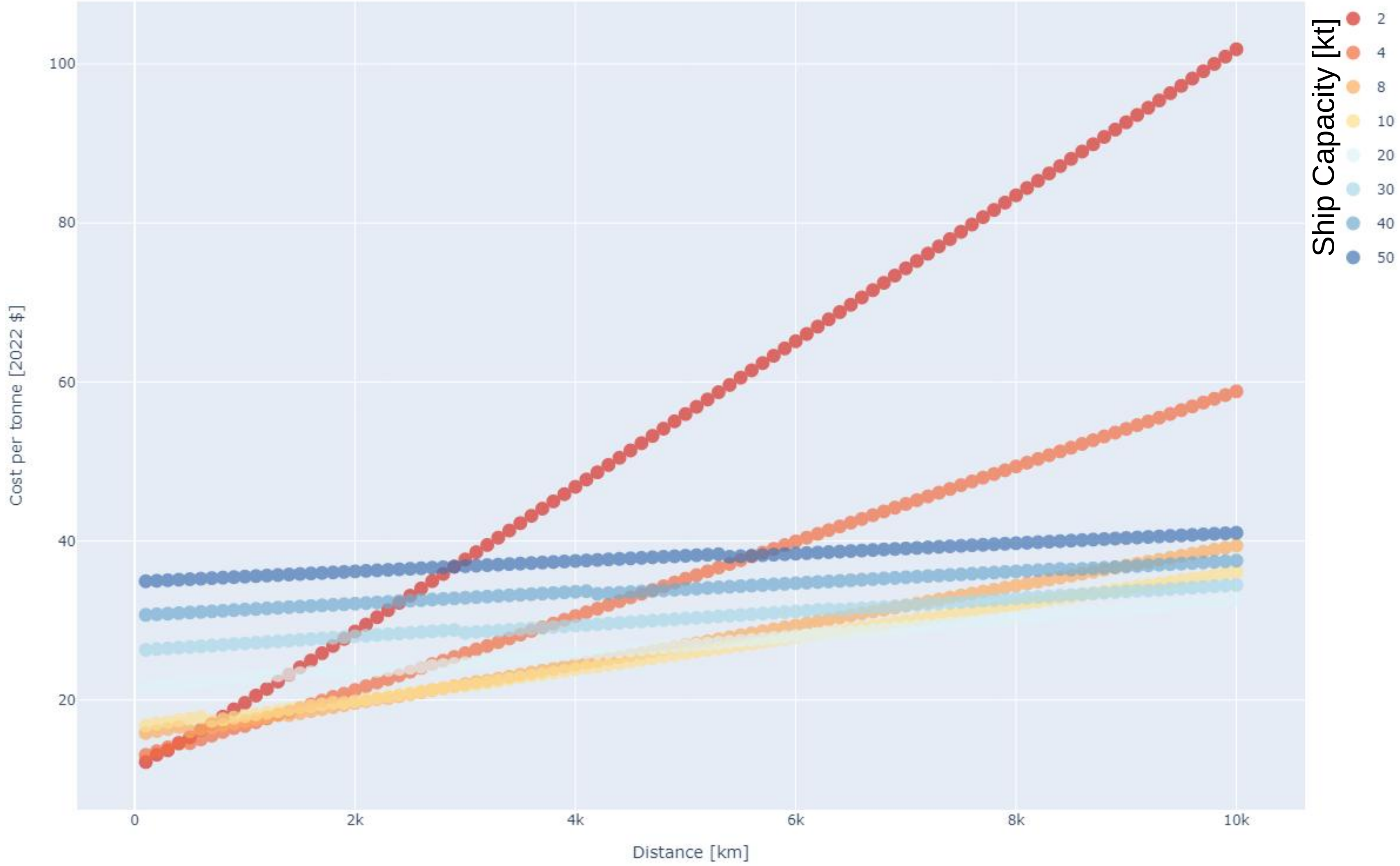


Resulting CO_2 Pipeline Routing Surface



Maritime CO_2 Cost Modeling





Based on:
https://www.gov.uk/government/publications/shipping-carbon-dioxide-co2-uk-cost-estimation-study

OVERVIEW: SimCCS^{PRO} Optimization Model

SimCCS^PRO – CCS Value Chain Optimization Tool

Integrated CCS assessment

- Simultaneously understand capture, transport, & storage of CO_2.

Capture

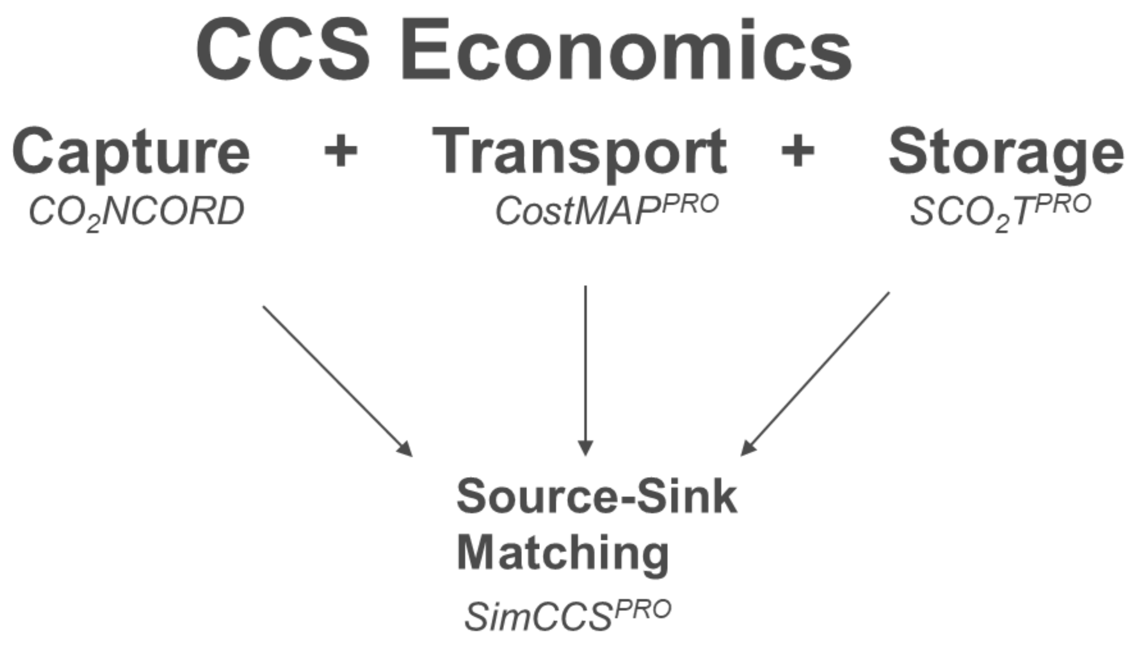
- CO_2 emissions, capturable CO_2, CO_2 purity by multiple streams, economics over space & time.

Transport

- **Routes:** Potential routes considering multi-dimensional geographies.
- **Pipelines:** Capacities, trunklines to aggregate CO_2, economics (capital, fixed & variable O&M).

Storage

- **Storage:** Identify ideal sites, dynamic CO_2 injection & storage, life-time reservoir costs (injection, storage, & PISC).
- **Utilization:** Oil, shale gas, geothermal, & materials.



Over Seventeen Scenarios were Modeled

- A scenario consists of a predefined set of sources, geologic sinks, and modes of transport (See table)
- Scenarios were selected from two source groups
  - All electric generators, or
  - All sources (electric + Industrial)
- Scenarios were selected that allowed for storage only in the Eastern Seaboard region, offshore only, onshore only, and in all sinks
- Barge transport was active in two of the scenarios
- The model can be run in capacity or price mode.

Scenarios	Sources		Sinks					Barges
	Electric Sources	All Sources	Offshore HC	Offshore All	Onshore Gulf	Appalachia	Eastern Seaboard	
Electric_Offshore_HC	X		X					
Electric_Offshore_All	X			X				
Electric_Gulf_Offshore_All	X			X	X			
Electric_Gulf_Appa_Offsh_All	X			X	X	X		
Electric_EastSeaboard	X						X	
Electric_onshore	X				X	X	X	
Electric_allSinks	X		X	X	X	X	X	
Electric_allSinks_barge	X		X	X	X	X	X	X
Allsources_onshore		X			X	X	X	
Allsources_allSinks		X	X	X	X	X	X	
Allsources_allSinks_barge		X	X	X	X	X	X	X

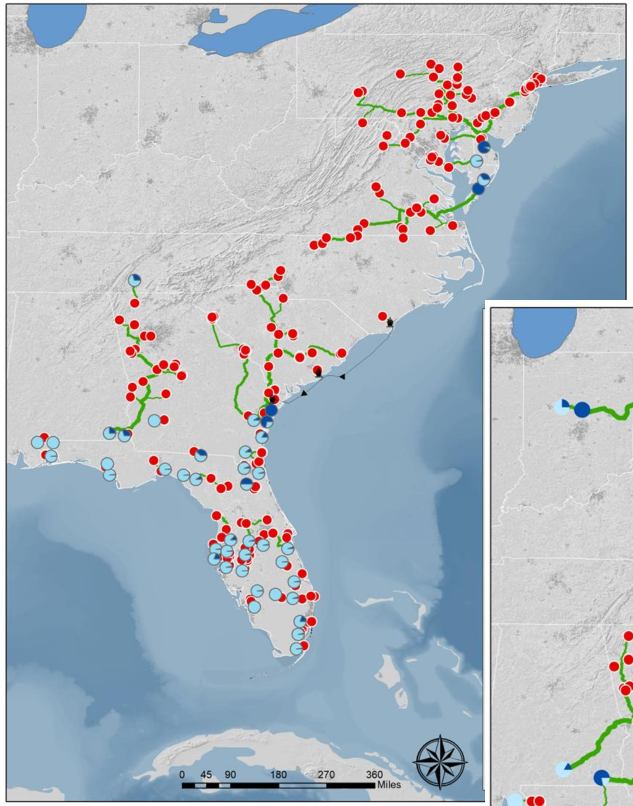
Unit Cost Summary for CCS by Scenario

- Offshore has the highest transport and storage costs
- CCS costs tend to decrease as the candidate storage areas increase …more degrees of freedom
- Barge transport deploys only to a limited extent even if the price is artificially dropped below the base value
- Negative total unit costs are observed using the model’s price mode set equal to the 45Q tax credit value ($85/t)

Scenario	Results (lower feasible gap)				
	TOTAL Capturable CO2 (MtCO2/yr)	Capture Unit cost ($/tCO2)	Transport Unit cost ($/tCO2)	Storage Unit cost ($/tCO2)	Total Unit Cost ($/tCO2)
Electric_Offshore_HC	276.23	57.25	19.57	22.31	99.13
Electric_Offshore_All	276.23	57.25	16.12	22.92	96.29
Electric_Gulf_Offshore_All	276.23	57.25	20.35	5.72	83.32
Electric_Gulf_Appa_Offsh_All	276.23	57.25	19.05	5.26	81.56
Electric_EastSeaboard	276.23	57.25	11.27	5.66	74.18
Electric_onshore	276.23	57.25	10.77	5.81	73.83
Electric_allSinks	276.23	57.25	10.85	5.63	73.73
Electric_allSinks_barge_100	276.23	57.25	9.87	5.80	72.93
Electric_allSinks_barge_95	276.23	57.25	9.80	5.73	72.79
Electric_allSinks_barge_90	276.23	57.25	9.77	5.76	72.79
Electric_allSinks_barge_85	276.23	57.25	9.76	5.72	72.73
Electric_allSinks_price_85	231.17	56.36	9.32	-79.33	-13.65
Electric_allSinks_barge_100_price_85	229.51	56.32	8.06	-79.44	-15.06
Allsources_onshore	364.32	58.16	11.38	5.74	75.28
Allsources_allSinks	364.32	58.16	11.28	5.70	75.14
Allsources_allSinks_price_85	305.21	57.42	8.88	-79.27	-12.97
Allsources_allSinks_barge_100_price_85	298.87	57.26	8.08	-79.70	-14.36

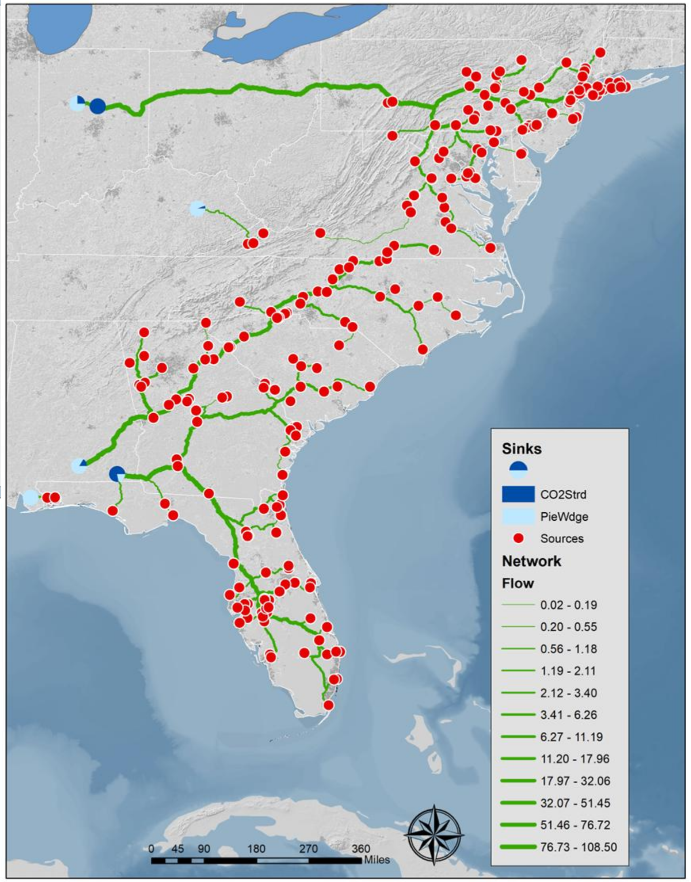
Transport Summary

- Transport costs range from \$8–\$20/tCO_2 across all scenarios
- Transport costs are generally less expensive when utilizing onshore storage compared to offshore and less expensive when barging is considered along with pipeline transport
- Several recurring trends were found during the integrated scenario infrastructure analysis
  - In Florida, micro-pipeline networks formed linking a couple of CO_2 sources to individual geologic sinks
  - Elsewhere, medium clusters of sources were linked by pipeline to form larger storage hubs.
- A comparison of scenarios found that several common CO_2 trunklines emerged. This study identified the following potential trunklines:
  - A connection between the Eastern Seaboard and low-cost storage sites in Indiana or Kentucky
  - A trunkline that consolidates all CO_2 emissions from the northern Eastern Seaboard and follows the Appalachian Mountains, leading to storage in the onshore Gulf Coast region while also capturing additional CO_2 along the route
  - A trunkline dedicated to the collection of captured CO_2 in Florida, western Georgia, and the Carolinas that leads to storage in Florida



← Florida micro-pipeline networks

Emergence of CO_2 trunklines occurred in some scenarios →



2.2: U.S. Eastern Seaboard Transport and Storage Study: Summary of CO_2 Transport Costs

XODUS

8th CCS Cost Network Workshop

Colin Laing
Advisory Team CCS Lead

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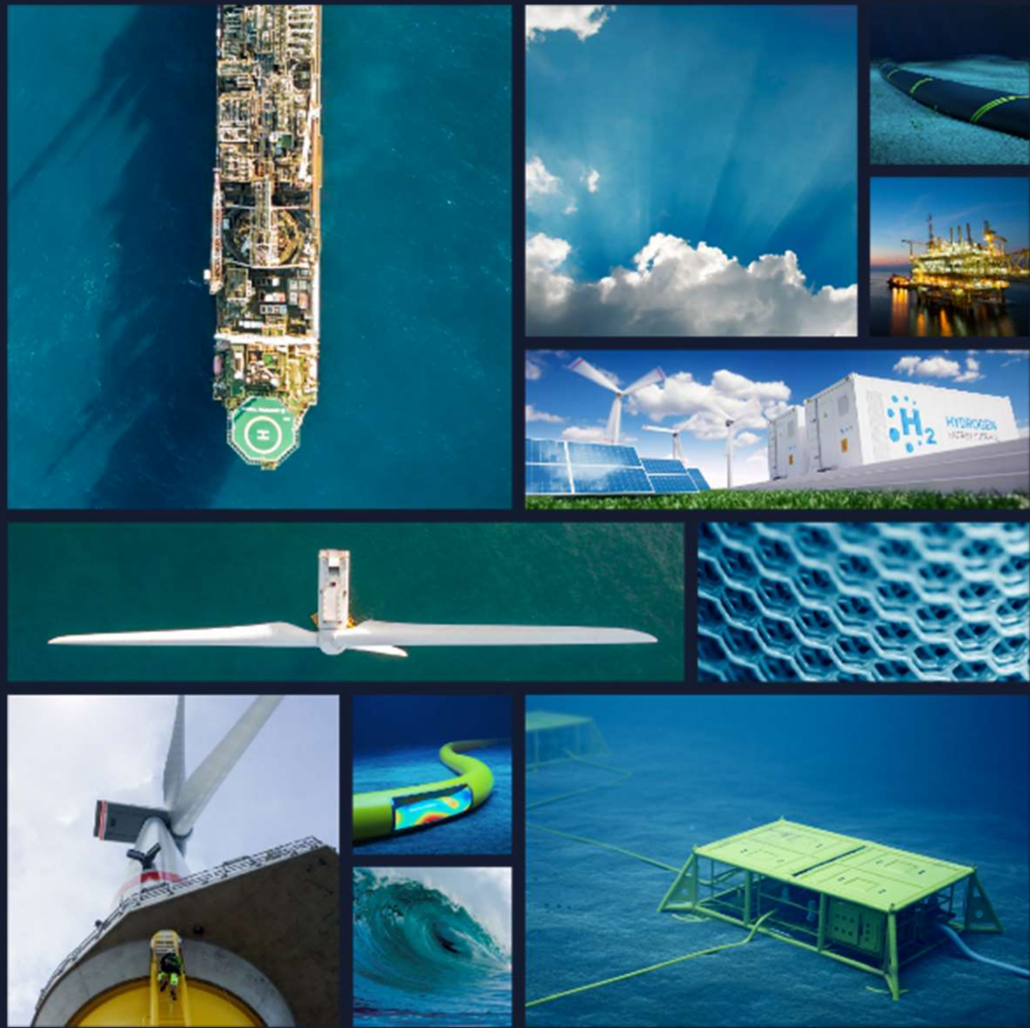


Agenda

- Introduction
- Case Study – Domestic UK Gas Pipe estimating
- Gated Process for bespoke infrastructure
- Messaging to the stakeholders

Who is Xodus Group?

Xodus has been established for over 15 years and now has more than **400 experts** working across the globe. We provide all the skills to help our clients thrive in an evolving energy world.

- 450+ technical personnel
- 18 years average experience, UK HQ/Global Presence
- **In the last 3 years, we have advised on $50 billion in equity transitions**
- Over 7,000,000 work-hours dedicated to completing more than 15,000 projects. Servicing all stages of a project's lifecycle over the full spectrum of the energy industry
- Over 500 clients and 70+ MSAs globally with majors, independents and NOCs

XODUS CCUS HIGHLIGHTS

We combine subsurface and surface skills in CCUS under one roof

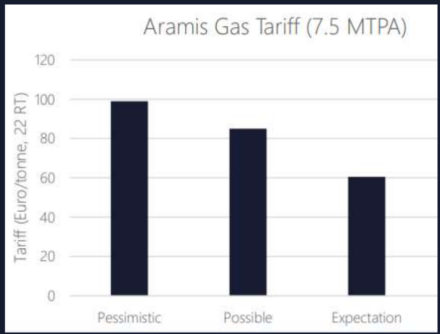
We have current operational experience on a live CCUS plant and bring key learnings back into design

We understand the environmental impact of a CCUS project and how to permit those projects

We understand the economics behind CCUS projects and how government support can able them. We also have key resources who have recently joined us from UK regulators

Our owners (Subsea7) are the only company to have installed an offshore CO2 pipeline in Europe to date

CCUS Highlights – Offshore T&S Focus



Porthos / Aramis CCS Due Diligence

Dutch Government

Technical and commercial due diligence of proposed Porthos and Aramis CCS schemes covering all aspects of transport and storage within the system, including tariff setting

Gorgon CCS Support

Chevron

Operational process engineering support for the detailed design, start-up and operational phases of the Gorgon CCS project, including re-engineering of the CO2 transport system

European Trans-Border CO2 Transport Enablement Study

CCSA

Detailed analysis across all European CO2 emitters and potential routes to North Sea based stores for their emissions to assess the business case for new infrastructure to support cross border CO2 transport

Northern Endurance Partnership ESIA

BP

Full chain service for environmental statement and associated impact assessment for Northern Endurance Partnership CCUS project located in North-East England and exporting CO2 to a saline aquifer in the North Sea

Personal Introduction

Chemical Engineer Background working for O&G companies

- Offshore production, Midstream, Petrochemicals
- Operations and Development Engineer

Time spent with UK Energy Regulator, Ofgem,

- Gas Transmission and New Nuclear (Sizewell C) and CCUS Network
- Technical and Commercial review of NEP, Hynet

Xodus role is focused on the technical and commercial aspect of the industry

- Led the Aramis Tariff review team
- Working with CCSA in Europe on Costs/Value

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Case study

UK Domestic “Natural Gas” pipeline estimating

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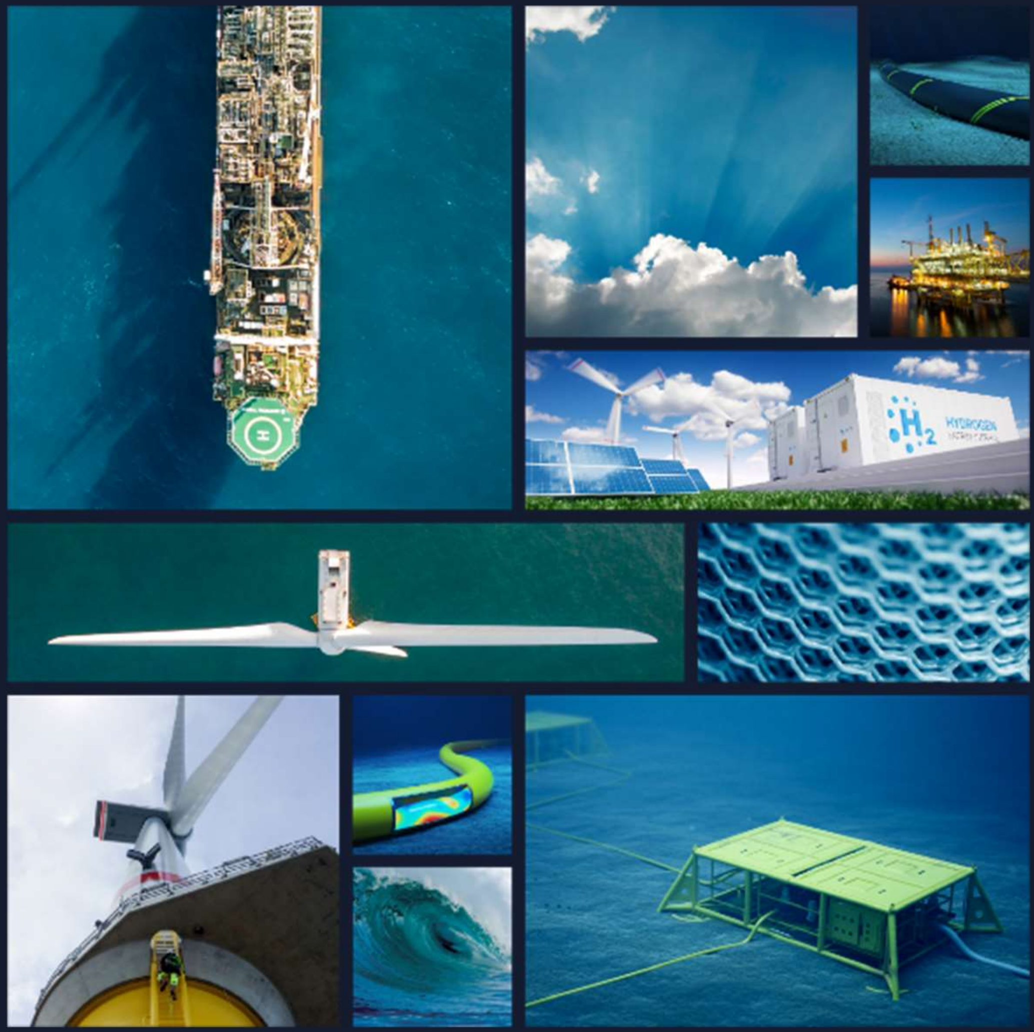


Workshop Discussion

The costs associated with the critical transport component of the CCS value chain are frequently underestimated in studies. ***Reliable cost estimates remain challenging to obtain,*** *and data from real projects often reveal* ***significantly higher costs than initial projections.***

This session seeks to shed light on ***existing cost data from real-world projects,*** *explore the limitations of current data, and identify opportunities for improvement, aiming to deepen understanding of CO_2 transport costs across different modes and support more accurate future estimations.*

UK Domestic Gas Pipelines

Low Pressure Pipes

Typically <30 mbar but up to 7 barg

- **Up to £800m spent annually**
- **Replacing pipes along same route, insertion.**
- High volume of work, known volumes, 100kms of pipe replaced
- Over 30yrs of experience
- Relatively fluid contractor market for pricing

High Pressure Transmission Pipelines

Typically steel and 80 barg pressure

- **£80-100m spent annually**
- **Building new pipelines along new route**
- Lower population and lower volume of work
- Over 30 yrs of experience
- Less fluid contactor market linked to lower population of work

UK Domestic Gas Pipelines - Allowed Costs

Low Pressure Pipes

supplying domestic properties, typically plastic pipe

- Data drawn from **5 operators and 10+ contractors**, and 30 years of data
- Estimated using a **regression model**
- Price in £/m is set and accepted by parties up to **5 years ahead**
- "Turn Key" price set **before** routing and the scope is known in detail

High Pressure Pipes

Supplying power and industry. Steel, 80 barg

- Data from a **single monopoly operator**
- Estimates are **bespoke** and based on named project. Effort to build confidence
- Project budget based on contracts offered **1yr ahead of construction**
- "Turn Key" Price set only **after** routing is very well understood,

Difference in Approach

Setting costs for newbuild, new route pipelines are influenced by location specific factors

Locational Factors

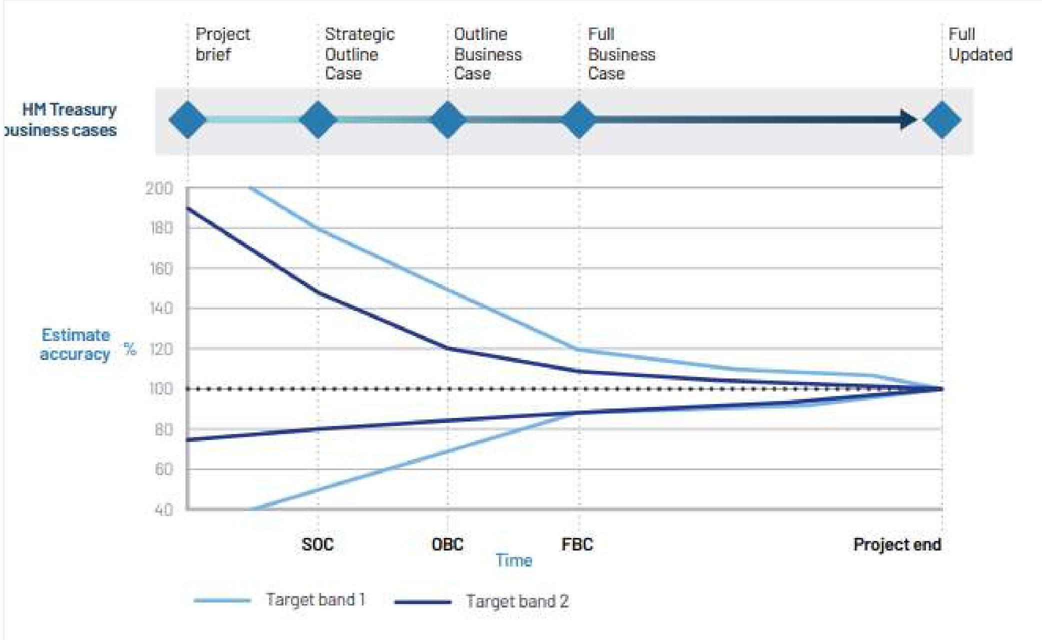
- Evidence shows that installers cannot provide firm costs without understanding location specific factors.
- Road / River Crossings and clashes with existing infrastructure and plays an important role
- **Routing options will have huge influence on cost**

Estimating Challenges

- Reliable estimating of location specific factors is challenging without expending effort (£s)
- **Market price and activity levels will have a huge influence on cost**
- **Allocating construction risk has a major influence on cost**

The risks are controlled by a gated development process (of some kind)

A Gated Process



Stage Gates	SOC		OBC		FBC	
Ref. Classification	5		4-3		3-2	
Typical project maturity	<5%		30%		>60%	
Target range	-20%	+50%	-15%	+30%	-10%	+10%
By exception	-50%	+100%	-30%	+50%	-10%	+20%

- Every Company uses broadly the same process.
  - CVP/ND500/PEP/CDPEP/PMS/PDEP
- A gated process manages the risk of the business plan not delivering expected outcomes.
- Balancing the cost of understanding risk vs the benefit of understanding risk.
- Differing Methods, whole different argument

- Accuracy drives expense with FBC or FID requiring a spend of around 10% of Total installed cost of a T&S system not uncommon.
  - £100m pre-FID development cost is not unusual for offshore T&S network

*The costs associated with the critical transport component of the CCS value chain are **frequently underestimated** in studies. **Reliable cost estimates remain challenging to obtain,** and data from real projects often reveal **significantly higher costs than initial projections.***

Key Factors:

Underestimated costs	• What was the estimate class, is the increase within expected range? • What are the unknowns and risks caried in the estimate and when are these costs realised in the estimate?
Reliable costs	• Location specific cost drivers need consideration, was appropriate effort expended at the front end of the project? • How has inflation and wider industry activity influenced the estimate at each gate?
Wider Policy	• Whas there an incentive to increase or decrease the estimate to "win the prize" • How are permitting timelines and associated inflation effects considered?

Pipelines Wrap-up

Design development and **subsequent estimate maturity really matters**

What is the incentive and how does it change the story

Execution timeline and strategy influences outcomes

Note on Shipping

Topic of investigation in partnership with CCSA, Subsea7 and others.

Similar drivers influence cost of ships or rail (or road)

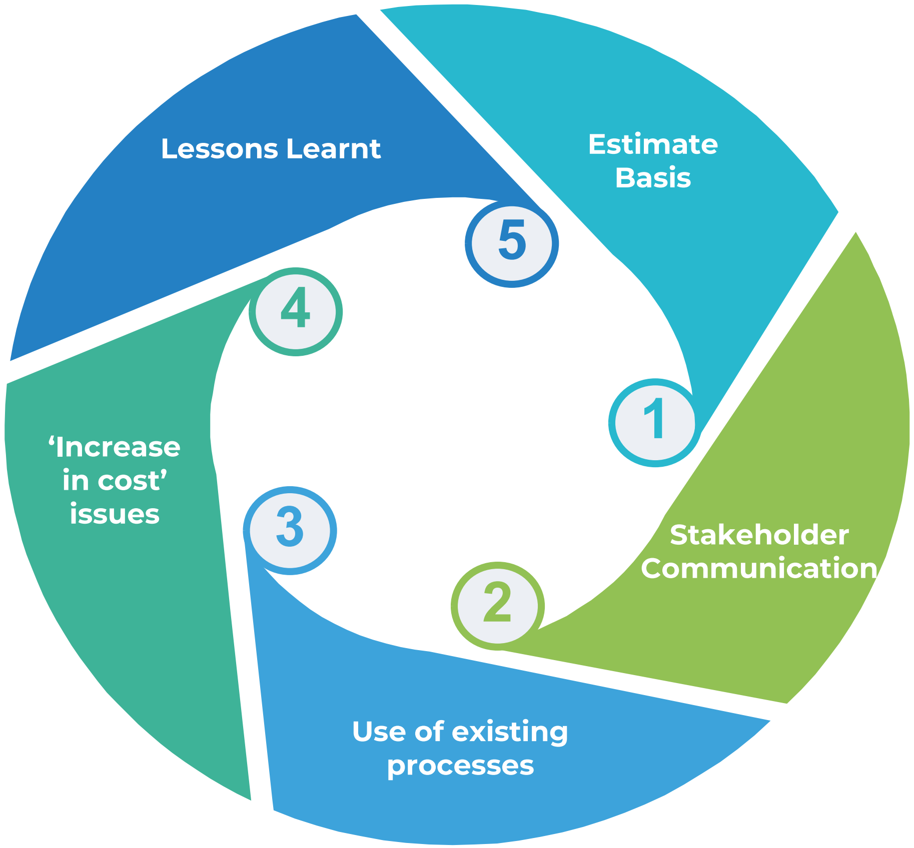
- Distance, parcel size, user base, location and utilisation

Same issues arise when estimating associated infrastructure

- Onshore Tanks, Jetties, River Approaches etc will all have location specific factors
- Maturity, maturity, maturity

Communicating with Stakeholders

How do we communicate costs to avoid mismatched expectations?



1. What was the basis for the estimate?
2. How did we communicate the uncertainty?
3. How do we use existing processes to build confidence?
4. How are we working to avoid the "costs have gone up again" headlines?
5. Can we learn from other sectors?

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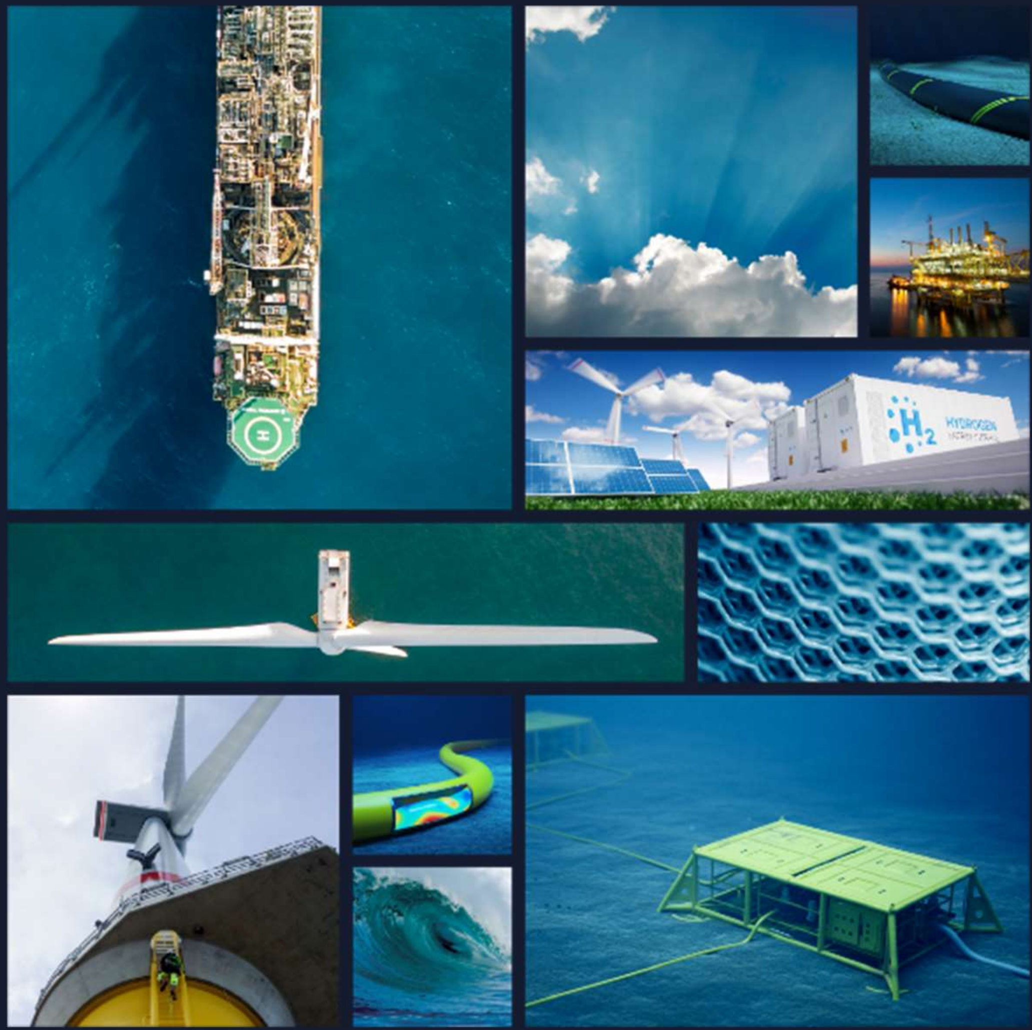
T&S Costs

Published costs and Discussion



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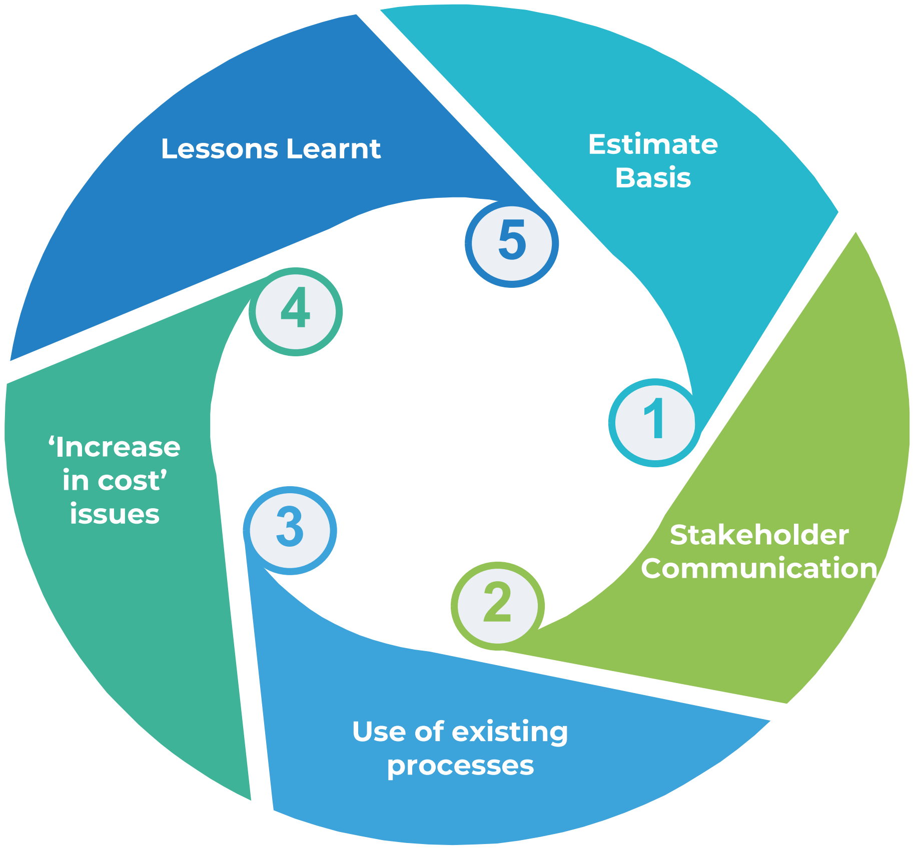
T&S Cost Publication Summary

	There is limited cost data publicly available	Most published information is linked to Government supported projects	The key elements of lifecycle costs are not clear	There is a mix of project archetypes globally
Summary	• Capex and Opex costs sit in a wide range • There is limited recent information published for large scale developments • Current evidence base is limited to high profile projects and Government publications	• Given commercial sensitivity of costing information, most published studies are driven by Government • While the published information is useful, it is region, location and project specific	• The underlying assumptions are not always apparent, and inflation and financing costs aren't often segregated/ reported • The general accuracy of costs are not often highlighted	• Projects are heavily influenced by the location of emitters, stores and utilisation • Perceived trends in region often have a number of "exceptions to the rule"

Country	Project	System Architecture	Capex Cost Estimate Accuracy	System Capacity	Project Life	Financing Costs	Year of Reporting	Unit Costs
UK	Hynet	• Onshore and Offshore Pipelines Repurposed & New build • Depleted Gas Store	• +/- 30% • Advanced Development (Pre-FID)	Up to 10MTPA	25	10% WACC	2022	**Tariffs:** £38.5/T – 1MTCO2 £17.5/T – 5MTCO2 £10/T – 10MTPA
Netherlands	Porthos	• Onshore and Offshore Pipelines • Depleted Gas Store	• Not Stated • Advanced Development (Pre-FID)	Up to 2.5 MTPA	15	Not Stated	2020	**Tariffs:** £31.93/t– 2.5 MTPA £44.73/t– 1.75 MTPA
Netherlands	Aramis	• Onshore and Offshore Pipelines (New build) • Depleted Gas Store	• +/- 25% to 35% • Advanced Development (Pre-FID)	Up to 21 MTPA	15	Not Stated	2024	**Tariffs:** £76.67/t Pipeline - 7.5 MTPA System Capacity £95.33/t Ship – 7.5MTPA System Capacity
Norway	Northern lights	• Liquid Shipped Gathering • Offshore pipeline • Aquifer store	• Not Stated • Advanced Development (Pre-FID)	Up to 1.5 MTPA	Not Stated	Not Stated	2020	**Tariff (assumed):** £45.89/t (transported and stored) - 0.8 MTPA
Canada	Quest	• Onshore new build pipelines and onshore store • Aquifer Store	• Operational	Up to 1.2 MTPA	25	Not Stated	2023	**Life of Project T&S Cost:** £15.29/t – 1.1 MTPA
Canada	Alberta Trunkline	• Onshore Pipelines and Onshore store • Depleted Oil Store	• Operational	Up to 14.6 MTPA	25	Not Stated	2023	**Life of Project T&S Cost:** £22.22/t- 1.62 MTPA

Communicating with Stakeholders

How do we communicate costs to avoid mismatched expectations?



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4. How are we working to avoid the "costs have gone up again" headlines?
5. Can we learn from other sectors?

Session 3: Realistic Financing Assumptions

3.1: Finance Costs Drive CCS Cost: What Factors Drive Finance Costs?

Finance Costs Drive CCS Cost
What Factors Drive Finance Costs?

IEAGHG Cost Network Meeting
Houston TX
March 5, 2025

Jeffrey D. Brown
+1 (425) 503-0714
jdb@b2e2llc.com
jdb79@stanford.edu

ENERGY FUTURES INITIATIVE

B2 E2
BROWN BROTHERS
ENERGY & ENVIRONMENT

Sections of Today's Discussion

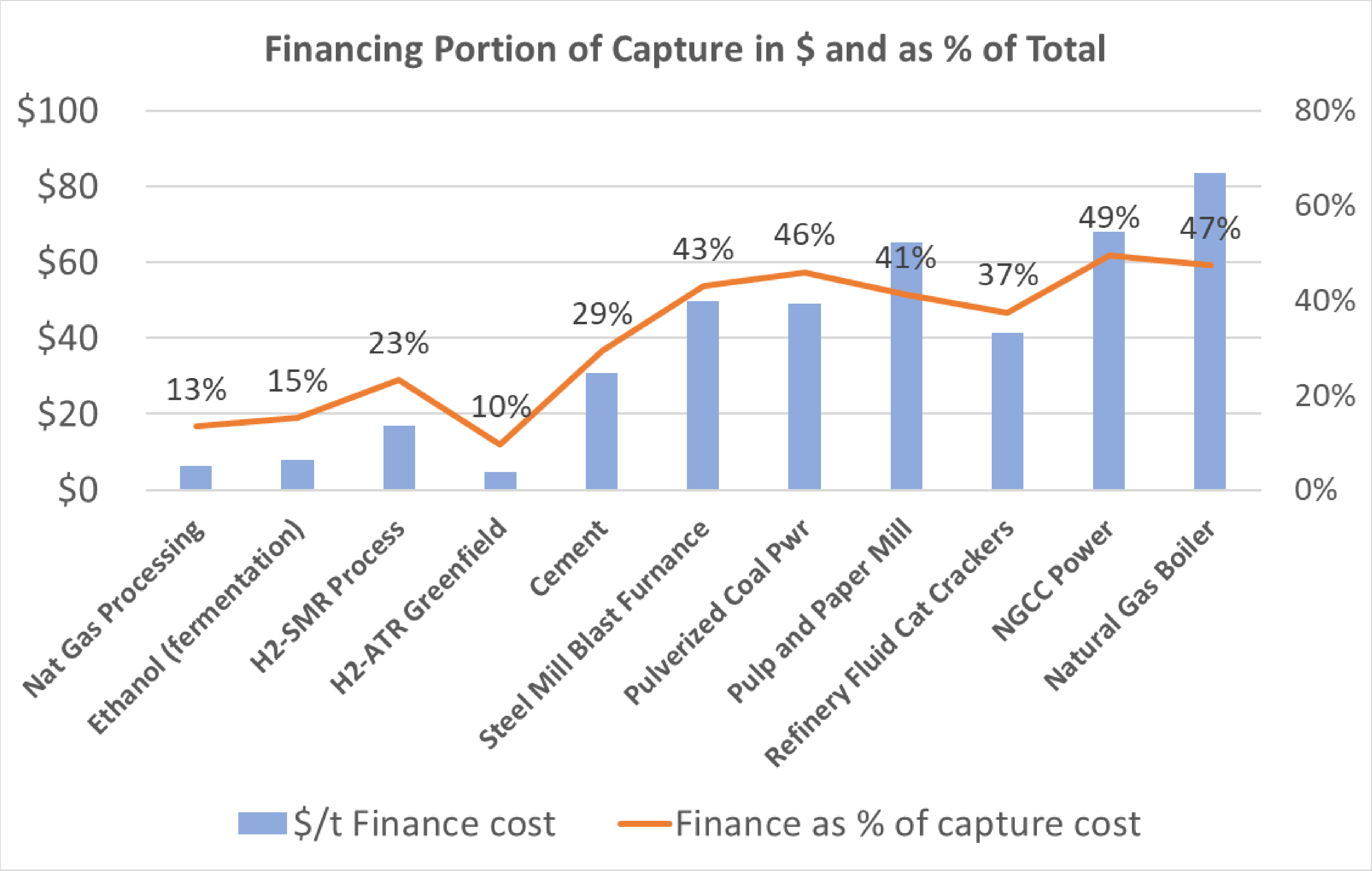
1. **Finance Costs Drive CCS Costs:** Roughly 50% of total cost per ton captured & sequestered.
2. **Increase in §45Q Eroded:** ~$50+/tonne worth of inflation, higher interest rates, & other factors wiped out the ~$35/tonne benefits of the IRA boost ($50/t → $85/t)
3. **Economics Still Challenged:**
   - A few low-cost/insignificant industries are feasible at $85/ton
   - CCS costs for industries/emitter types making up the bulk of stationary emissions are not close to this cost level—even for NOAK.
4. **Changes to 45Q:** What could swing the balance toward victory?
   - FOAK+: Stronger industrial policy, change "denial of double benefit", and fix Class VI backlog
   - NOAK: Significantly higher 45Q for 12 years
5. **Finance costs depend on who you are:** Access to cheap debt and ability to use all tax deductions makes a big difference.
6. **Power Sector is extra hard:** low dispatch rates and new EPA regs
7. **EOR makes financial and environmental sense, but is unloved**

Getting on the same page

- **Cost per ton**:
  - "Cost of capture" (in \$/t) is the cost you need to recover from revenues to pay for variable operating expenses, fixed O&M, & financing costs (e.g., mortgage).
  - "Cost of equipment" (in \$/t/yr) is the original investment divided by the CCS system's capacity to capture CO2 in one year. I.e., unit capex per 1 tonne captured in 1 year.
    - If Tundra cost is \$2 billion to capture 4 million t/y, \$2B÷\$4M= \$500 per-ton per-year
    - Rule of thumb: original cost of equipment (\$/t/yr) is about 2/3rds of "capture cost."
- **FOAK vs. NOAK**:
  - FOAK is 1st-of-a-kind of a CCS system, of a particular technology, deployed in a particular industry.
  - We'd call FOAK +next ~5-10 units the FOAK generation.
  - NOAK is "Nth"-of-a-kind" are the post-FOAK generation, i.e., known proved tech.
  - FOAK bound to be far higher cost of equipment (i.e., +~40%).
  - *Virtually all government, consulting, and techno-economic literature is for NOAK.*
- **Quality of estimates:** This industry has near-zero "as-constructed" experience (except for gas processing, SMRs), few full engineering studies, and federal grant funded FEED info is secret (for 5 years). Same w/ interest and equity costs. Same with tax credit valuations.
- **Operating rates:** "Expert" and NETL use high operating rates for cost-per-ton calculations (e.g., 85%). *Those numbers are dead wrong for power plants.*

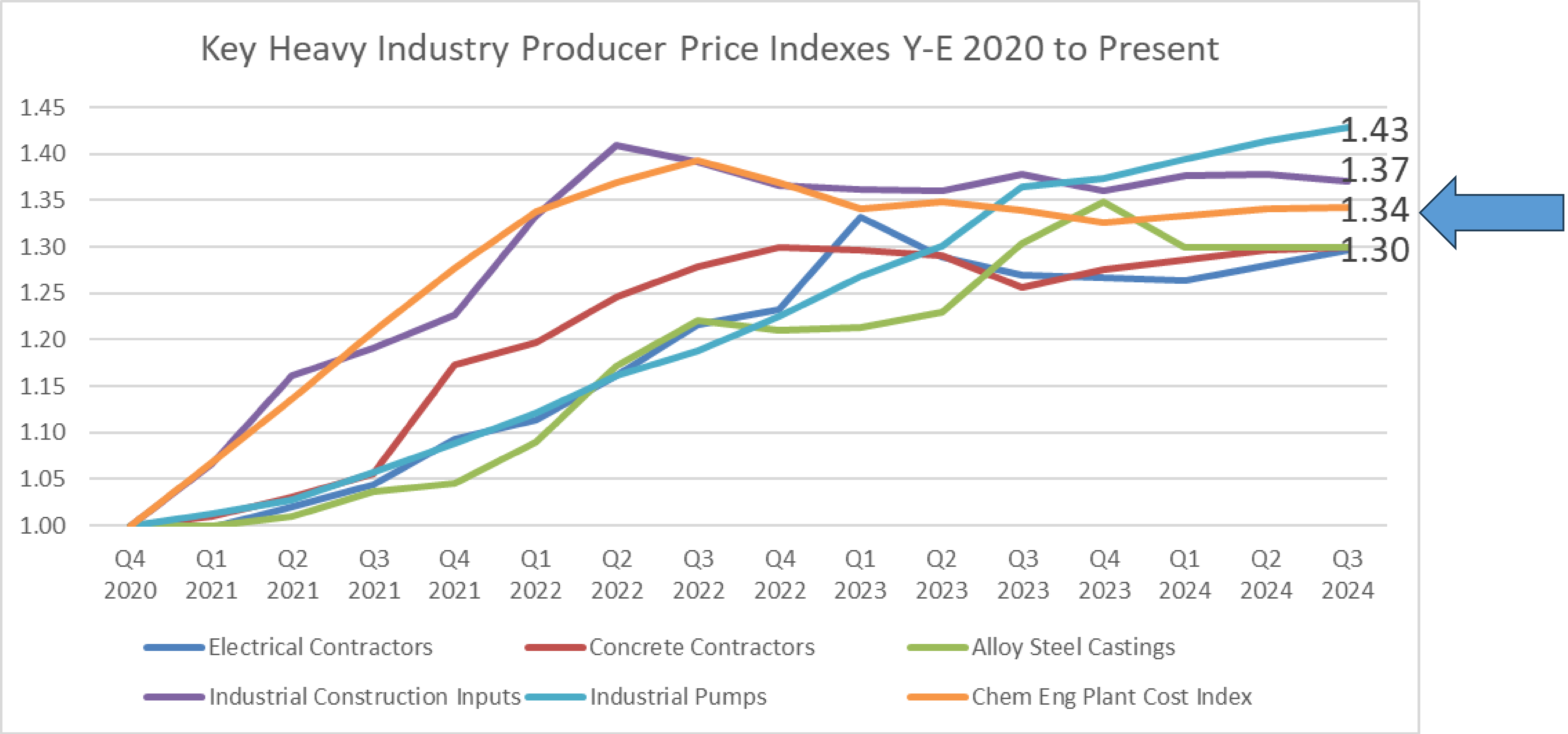
1. Finance Costs Drive CCS Costs

Financing 40-50% of Capture Cost in Target Industries

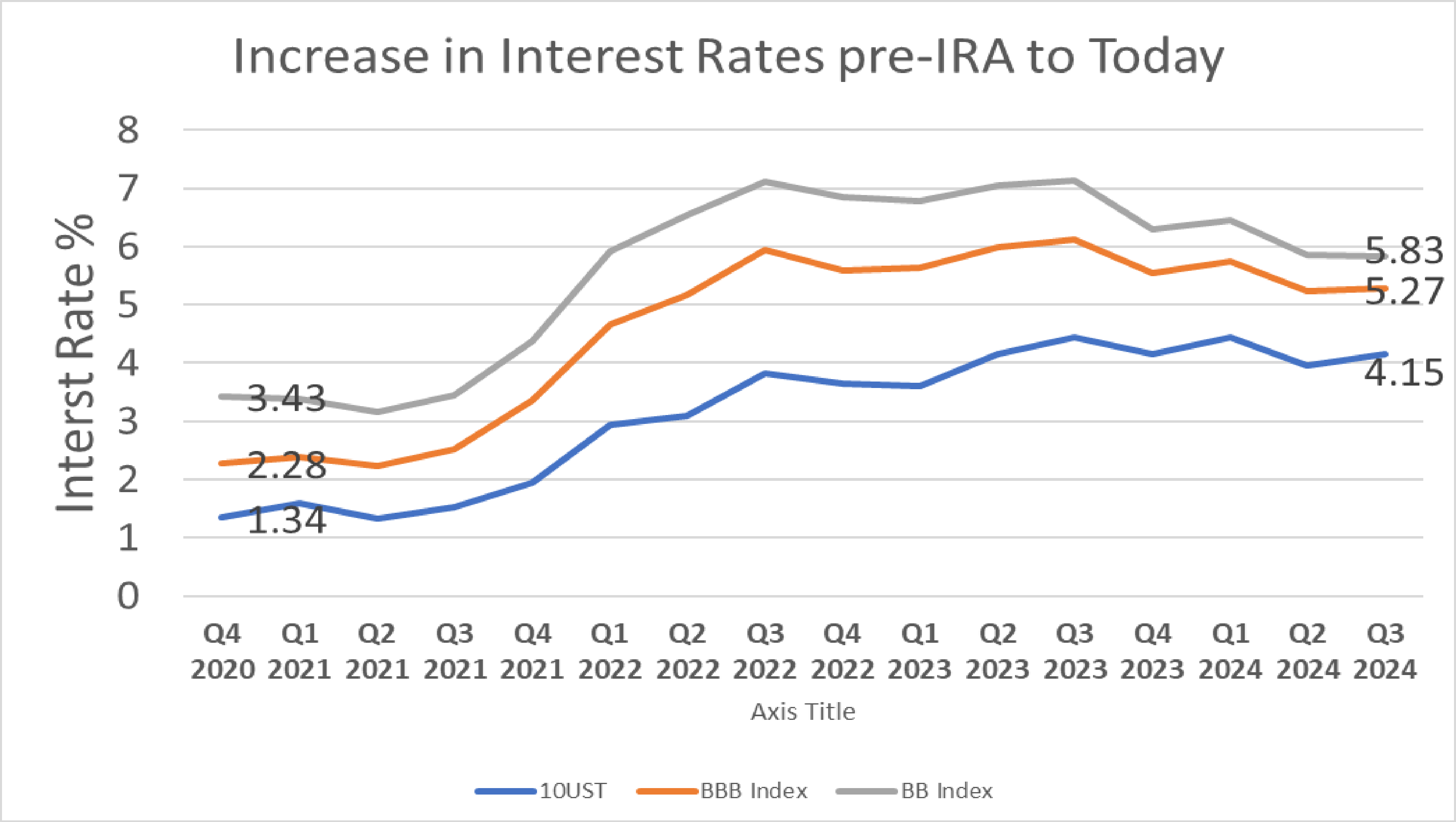


2. Inflation and Higher Rates Eroded IRA's Δ$35/tonne Increase to the §45Q Tax Credit [Now $85/tonne for Geologic Sequestration]

Heavy Industry Construction Inflation 30-40%



Debt: Interest Rates Up ~3% Across Credit Spectrum

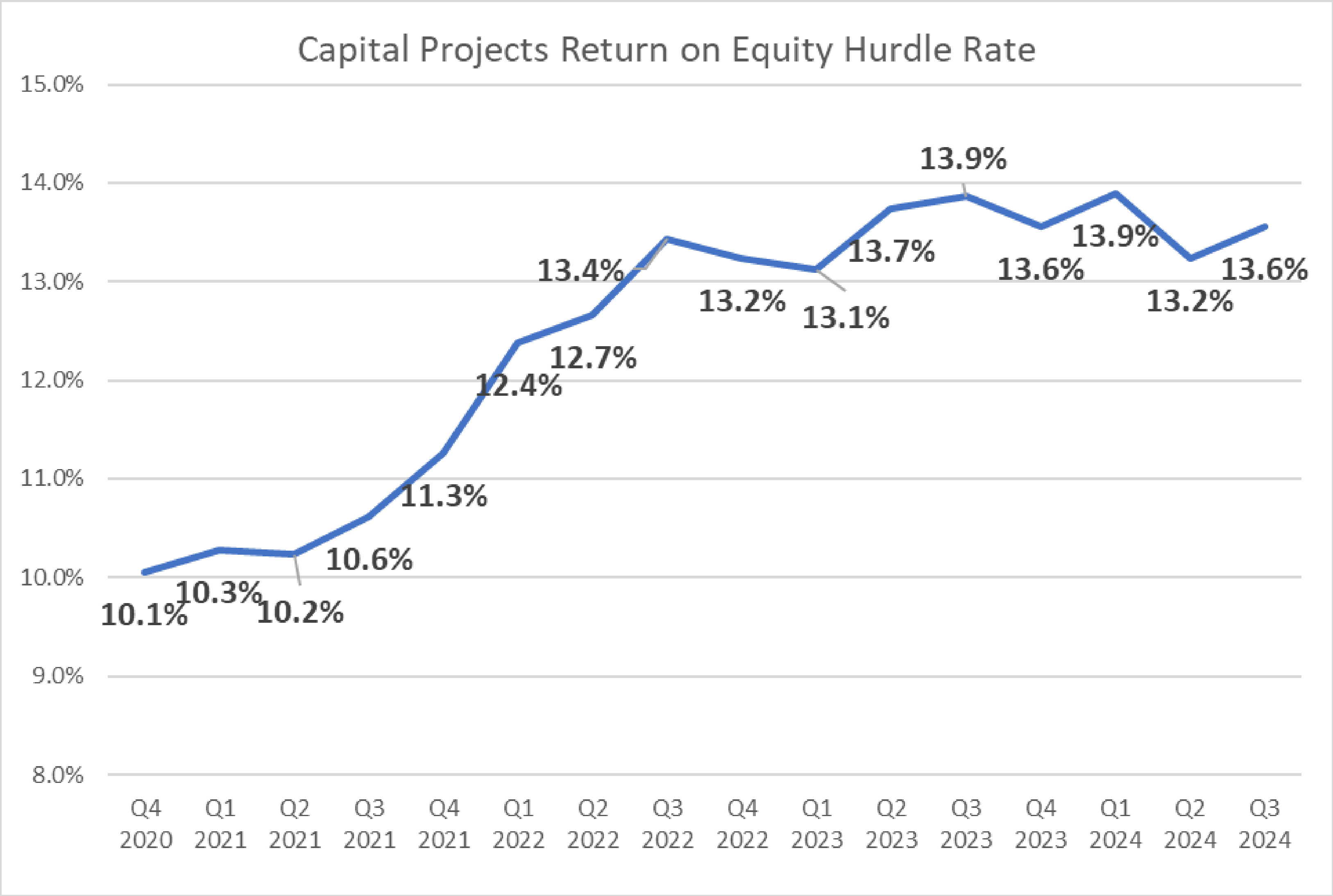


Interest Rates: All corporate and project debt bears an interest rate “spread” (extra % added to base U.S. Treasury “riskless rate.” Corporate debt rated from AAA (best) to BBB. BBB is lowest rated “investment grade” debt that can be acquired without special protections by conservative fiduciaries. BB is “sub investment grade”, lacking access to public debt markets, bearing higher rates, with short maturities. Note that the BB rates above are much better than those attainable by a CCS project financing—the BB rates here are for corporate “high-yield bonds” of established industrial companies.

Equity: Estimated Required Rate of Return for Internal Corporate Capital Investment y-e 2020 to date

Companies' internal equity target returns are non-public, however the formula used to estimate such targets here is based on a small premium (here 2%) above the Capital Asset Pricing Model public equity target returns. Up ~ 3.5% since 2020-Q4

Formula: [Risk free UST + (~5.5% * stock levered Beta)+2% project risk add-on. Beta used was 1.35%, from average of selected energy, midstream, chemicals, heavy construction, and oilfield services. **The GPI model runs use a target of 13.5%.**



§45Q Erosion: Example of y-e 2020 Capture Cost: "Representative Figures" *before* COVID Inflation, Rate Rise, Etc.

Cost Item	Units	X Input Cost	= Cost
Annual Financing Costs Full Corporate Taxpayer	$310[1]/tpy plant (NOAK)	8.48% per $tpy[2]	$26.29/t
Annual O&M	$310[1]/tpy plant	5% per $tpy	$15.50/t
Natural Gas per tonne	3 MMBtu/t	$3.32 per MMBTU[3]	$9.96/t
Parastic Energy per tonne	0.15 MWh/t	$71.8 per MWh[3]	$10.77/t
Transport and Sequester	1t sequestered/t	$15 per t captured	$15/t
			$78/t

[1]This figure was towards the middle of then-estimated greenfield emitter CCS NOAK capital costs across multiple CCS applications requiring capex for CO2 separation from flue gas cement, steel, coal, pulp, refinery cat crackers, NGCC, and gas steam boilers. ($190/tpy low and $508/tpy high).

[2] This figure represents a Capital Recovery Factor (covering annual rates on finance and repaying principal), that is roughly midpoint those of a full taxpayer and a standalone project with partial tax appetite via tax equity transaction.

[3] Gas and Electricity both from US EIA average price delivered to U.S. industrial customers for2021 average, from 2024 Monthly Energy Review.

Example of 2024 Capture Cost "Representative Figures" *after* COVID Inflation, Interest Rate Jump, Etc.-- $52/t Higher

Cost Item	Unit	X Input Cost	= Cost	Change
Annual Financing Costs Full Corporate Taxpayer	$498[1]/tpy plant	10.20% per $tpy[2]	$50.80/t	$25.5
Annual O&M	$498[1]/tpy plant	5% per $tpy	$24.90/t	$ 9.4
Natural Gas per tonne	3 MMBtu/t	$3.80 per MMBTU[3]	$11.40/t	$ 1.4
Electricity per tonne	0.15 MWh/t	$81.6 per MWh[3]	$12.24/t	$ 1.5
Pipe and Sequester	1t sequestered/t	$20 per t captured	$30/t	$ 15.0
			$129/t	$51.8

[1]This figure is towards the middle of 2024 estimated capital costs across multiple new CCS applications ($400/tpy low and $600/tpy high). The drivers of change were 1.34x inflation and addition of a 1.2x factor for retrofits (most projects in practice) vs. greenfield (the basis of most government and agency estimates). The $400-600 range excludes four industries that separate CO2 already but do not sequester; these are cheap and work at $85 today.

[2] This figure represents a Capital Recovery Factor (covering annual rates on finance and repaying principal) that is roughly midpoint those of a full taxpayer and a standalone project financing with partial tax appetite via tax equity transaction .

[3] Gas and Electricity both from US EIA average price delivered to U.S. industrial customers for 1st 8 months avg. 2024, from 2024 Monthly Energy Review.

Disaggregation of Main Drivers of the \$52/tonne Δ of Prior Page

Inflation (Capital and Energy)	$	22.2	43%	policy
Extra Cost of Higher Financing Rates	$	8.6	17%	policy
Extra Cost of Retrofit vs. Greenfield	$	11.2	22%	engineering methodology
Higher Pipeline and Storage Estimate	$	10.0	19%	policy
	$	52.0	100%	

3. NOAK CCS Costs of CCS for the Industries that Matter Remain Far Higher than §45Q Support

Falling Short

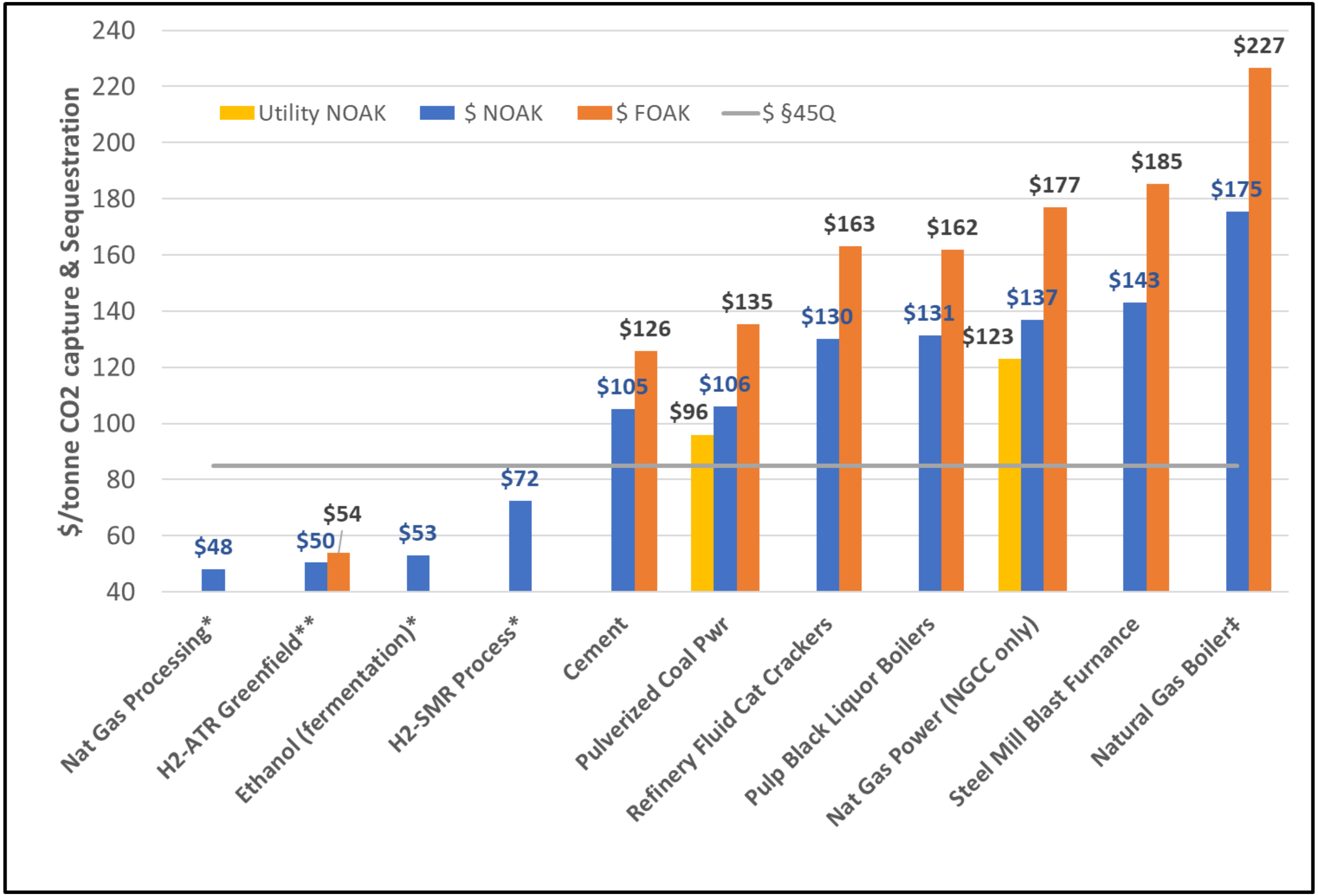
Notes:

"Capture Costs" include capture & compression plus assumed $30/tonne for transport/storage.

Because §45Q runs only 12 years, all debt and equity repayments must occur within 12 years.

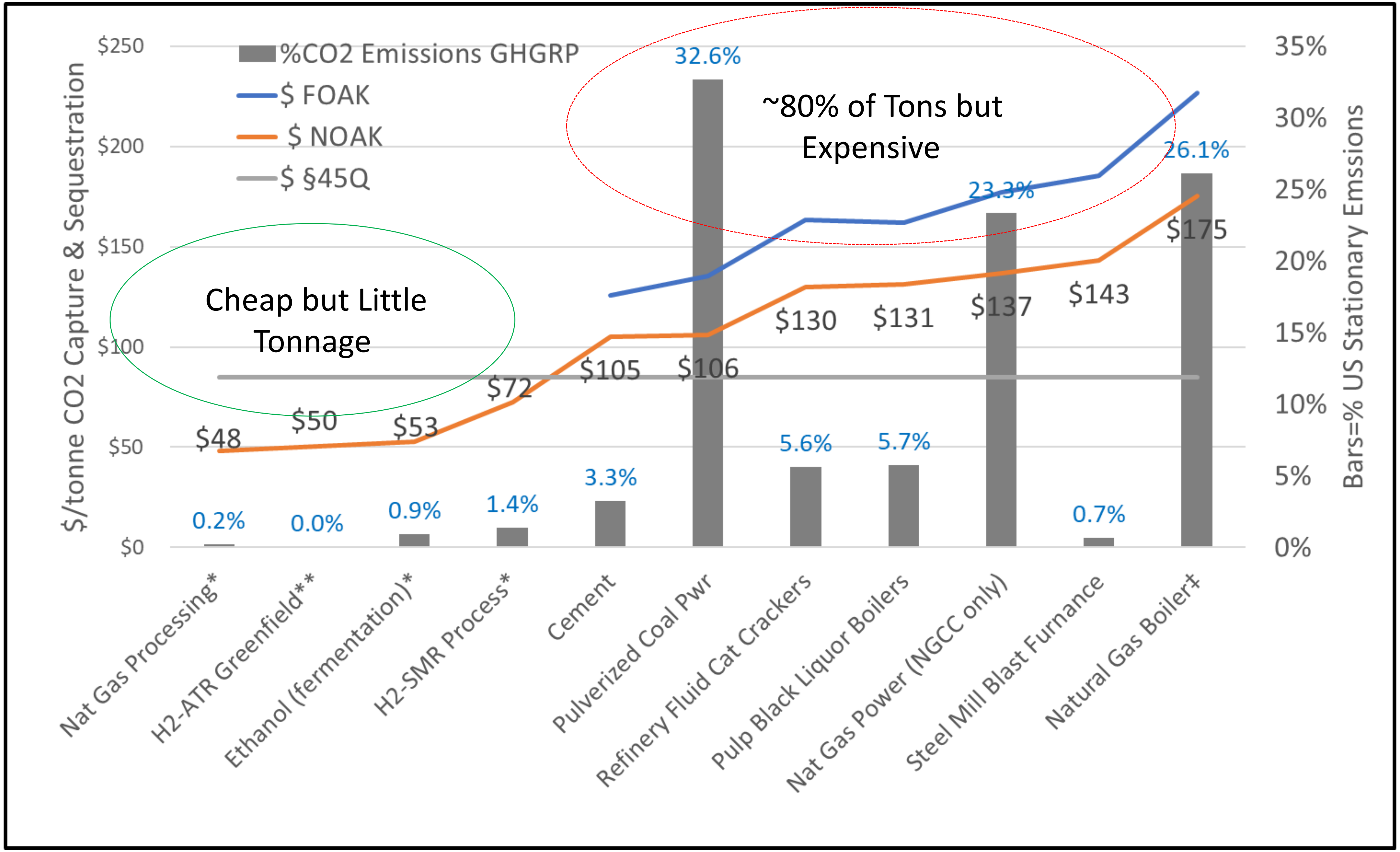
NOAK Financing Costs (i.e. Capital Recovery Factors) are 10.20%, which is a midpoint between corporate balance sheet/full taxpayer CRFs (~8.9%) & standalone project finance entities with partial tax appetite (11.30%)

Corporate debt assumed at 6% (UST+2%) vs. project debt at 7.5% (UST +3.5%)



*Already NOAK. **New, so no emissions. ‡ Highly approximate, no reliable cost studies.

Few Cheap Tons & Bountiful Expensive Tons



*No FOAK line because routinely generate pure CO2 and have been selling pure CO2 to oilfields for decades.

**Auto Thermal Reforming of methane to manufacture H2. Greenfield plants under development but no current emissions.

‡ No available public studies or real FEED/EPC data. This is a very rough estimate for boilers. Cheaper than NGCC because higher CO2 concentration, but also more expensive because scale is generally smaller than the ~1.6 million tpy of a base load 2x1 NGCC.

4. What Changes in Support Level Would Spark a Scale-up— in High Emitting/Expensive-to-Abate Sectors?

Two Sets of Changes Needed

1. Conscious, targeted industrial policies to drive down capture costs to NOAK levels & get rid of obstacles to pipelines and storage.

    - Change needed to IRA provisions that ban projects from receiving both a federal grant and a federal loan. This provision is counterproductive from a finance point of view, though on its face seemingly sensible. Projects need both debt and equity, and \$500 million-\$2 billion 1st-3rd of-a-kind projects don't have normal access to the debt and equity capital markets.
    - Much faster transition of Class VI siting authority from EPA to the states.

2. Build up the foundation of §45Q base support levels that would make NOAK projects feasible in the group of heavy industrial and power emitters that are responsible for ~80% of U.S. reported stationary CO_2 emissions.

    - While coal has been DOE focus for 15+ years, it is rapidly declining and new EPA regs will effectively put coal entirely out of business by 2037.
    - Natural gas emissions from two sources, industrial heat/CHP and NGCC combustion turbines together are nearly 50% of emissions.

Problematic Statutory Grant and Loan Constraints

1. To left, "denial of double benefit" language from IRA.
2. To right, termination of LPO loan authorization once three projects "for the same general purpose" are operating in the US.

(2) DENIAL OF DOUBLE BENEFIT.—Except as provided in paragraph (3), none of the amounts made available under this section for loan guarantees shall be available for commitments to guarantee loans for any projects under which funds, personnel, or property (tangible or intangible) of any Federal agency, instrumentality, personnel, or affiliated entity are expected to be used (directly or indirectly) through acquisitions, contracts, demonstrations, exchanges, grants, incentives, leases, procurements,

IRA §50141(d)(2) @ p.601/725

(b) An eligible Innovative Energy Project is a project that:

(1) Falls within a category set forth in section 1703(b) of Title XVII;

(2) Is located in the United States;

(3) Is at one location, except that the project may be located at two or more locations if the project is comprised of installations or facilities employing a single New or Significantly Improved Technology that is deployed pursuant to an integrated and comprehensive business plan. An Innovative Energy Project located in more than one location is a single Eligible Project;

(4) Deploys a New or Significantly Improved Technology; and

New or Significantly Improved Technology means

(1) A technology, or a defined suite of technologies, concerned with the production, storage, consumption, or transportation of energy, including of associated critical minerals and other components or other eligible energy-related project categories under section 1703(b) of Title XVII, and that is not a Commercial Technology, and that either:

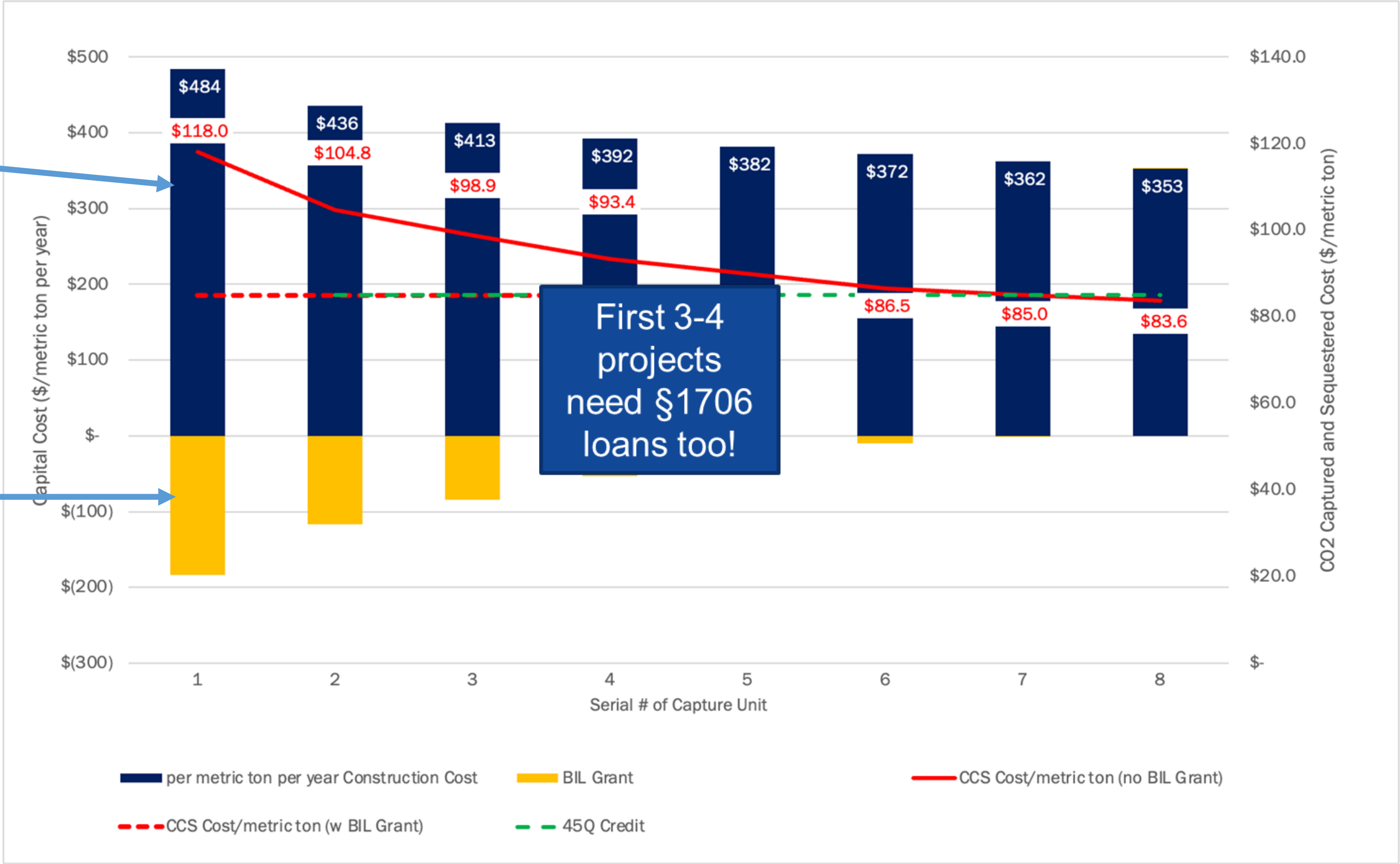
Commercial Technology means a technology in general use in the commercial marketplace in the United States at the time the Term Sheet is offered by DOE. A technology is in general use if it is being used in three or more facilities that are in commercial operation in the United States for the same general purpose as the proposed project, and has been used in each such facility for a period of at least five years. The five-year period for each facility shall start on the in-service date

https://www.ecfr.gov/current/title-10/chapter-II/subchapter-H/part-609

Driving Down FOAK Cost-of-Capture to NOAK Levels

First 3-4 projects need §1706 loans too!

Six plant grant package of ~$1/2 bn total



Class VI Backlog at EPA

Apparently the "8" Final permits issued include six recent ones (2 for Wabash and 4 for Elk Hills CRC). The three in final permit decision are for Oxy Low Carbon Ventures DAC project. 157 out of 161 wells waiting for EPA technical people to finish reviewing.

Projects Currently Under Review	Well Applications Currently Under Review	Final Permit Decisions Issued	% of Applications Received in Last 12 Months	Applications for which EPA is Waiting for Applicant Response	Applications Currently On Applicant Requested Hold
56	161	8	35%	53	3

Metrics for Well Applications Currently Under Review (by Review Phase)

Well Applications in Completeness Review Phase	Well Applications in Technical Review Phase	Well Applications in Prepare Draft Permit Phase	Well Applications in Public Comment Period Phase	Well Applications in Prepare Final Permit Decision Phase
5	152	1	0	3

https://awsedap.epa.gov/public/single/?appid=8c074297-7f9e-4217-82f0-fb05f54f28e7&sheet=51312158-636f-48d5-8fe6-a21703ca33a9&theme=horizon&bookmark=6218ffed-bb6e-42e4-a4f1-52d87e036a1b&opt=ctxmenu

Break-even Increase in §45Q

- Here we are using example of a 12-year 45Q payment and raising the level of the 45Q (in $/t captured) to meet debt service payment obligations and get to a 13.5% after equity return on project for the owner.
- Even with financing completely paid off in 12 years, the capture operations will cease after 12 years because there is zero policy support to cover ~$55 of Fixed and Variable O&M for capture and another $30/t of transport and sequestration expense

	Profitable Corporation (can use O&M, depreciation, interest deductions)	**Standalone Project/Tax Equity** (higher debt cost, less efficient use of deductions)
$400/tpy Lower End of NOAK Equipment Cost	**$109**	**$118**
$600/tpy Higher End of NOAK Equipment Cost	**$140**	**$153**

$130

Key assumptions: O&M is 5% of original capital investment cost, sequestration is $30/t, debt rate is 6% balance sheet/7.5% project with 12-year level amortization, with a minimum Debt Service Coverage of 2.0x (money available to pay mortgage is twice as big as the mortgage, establishing a safety margin demanded by lenders).

Break-even §45Q plus an 8-Yr. Operating Supplement

- **Here we added a post-45Q supplement at $85/ton to cover ~$84/t O&M at the high-end $600/tpy cost. The project runs 20 years, so cost/ton to Federal government < 45Q payment.**
- **A project will now capture an extra 8 years of emissions supported by the $85/t operating subsidy, i.e., $45/t less than the initial 12 years @ $130/t (average). Thus, the levelized cost of subsidy paid per tonne by the Federal government drops by about $15/t.**

	Profitable Corporation (can use O&M, depreciation, interest deductions)	**Standalone Project/Tax Equity** (higher debt cost, less efficient use of deductions)
$400/tpy Lower End of NOAK Equipment Cost	**$106** ($96/t to Feds)	**$117** ($107/t to Feds)
$600/tpy Higher End of NOAK Equipment Cost	**$139** ($122/t to Feds)	**$155** ($134/t to Feds)

$129 ($115/t Feds)

5. Why Does it Matter who Owns a Project?

CCS Projects Generate Large Depreciation and Interest Tax Deductions With No way to Use Them

- If the project is owned by a major corporation, e.g., Exxon, CF Industries, Air Products, Oxy the deductions will reduce taxes owed by the parent corporation. That benefit means the project has an extra source of equity income that lowers the §45Q level needed.
- If a standalone project, e.g., a greenfield blue ammonia plant, combines the product-making emitter with the CO2-capturing CCS, the product sales revenues may enable the project to use up the deductions.
- If neither, project may—or may not—successfully convince tax-paying investors to become equity partners.
- If none of the above, the deductions are "wasted."

The Break-even §45Q for a High-Cost Project Rises Sharply as Ability to Use Tax Expenses Falls

	Annual Tax Benefits to Three Owner Types		
Year	Corporate Full Taxpayer	Project w/ ~140/t sales revenues	Project with zero sales revenues
1	$ 45.7	$ 29.6	$ -
2	$ 60.6	$ 29.6	$ -
3	$ 44.3	$ 29.6	$ -
4	$ 34.5	$ 29.6	$ -
5	$ 34.3	$ 29.6	$ -
6	$ 26.8	$ 29.6	$ -
7	$ 19.3	$ 29.6	$ -
8	$ 19.0	$ 29.6	$ -
9	$ 18.8	$ 29.6	$ -
10	$ 18.5	$ 29.6	$ -
11	$ 18.2	$ 29.6	$ -
12	$ 17.9	$ 29.6	$ -
Sum of Tax Benefits	**$ 357.9**	**$ 355.3**	$ -
NPV to C.O.D.	**$ 203.7**	**$ 171.3**	**$ -**
NPV as % Project Cost	**34%**	**29%**	**0**
Needed 45Q	**$ 140.0**	**$ 150.0**	**$ 174.0**

6. Why are Power Plants so Hard & What Would Make a Difference?

What if Gas and Coal CCS Projects were Mandated by Regulatory Commissions?

- **Cost of Funds (Rates of Interest/Equity):**
  - Our average 6 ¾% interest rate assumption → **5% for utility debt**
  - Our required 13.5% after-tax equity rate of return → **10% for utility equity** (rate case rate of equity return).
- **Implication for Capital Recovery Factors (Rates + Amortization/Return of Capital) for a full taxpayer, NOAK:**
  - Our midpoint CRF for 2024 (12-yr life) is 10.20%.
  - Using 5% debt/10% equity the **utility CRF (12-yr life) drops to 8%.**
  - The utility CRF would be even lower if a 20-year financing period were used (5 1/2%)!
- **Lower 12-yr CRFs for a balance sheet financed/regulated project would reduce capture costs (*assuming 85% capacity factor*):**
  - NGCC NOAK 12-yr cost of capture @ 85% NCF of \$137/t →**\$123/t**.
  - Coal NOAK 12-yr cost of capture @ 85% NCF of \$106/t → **\$96/**t.

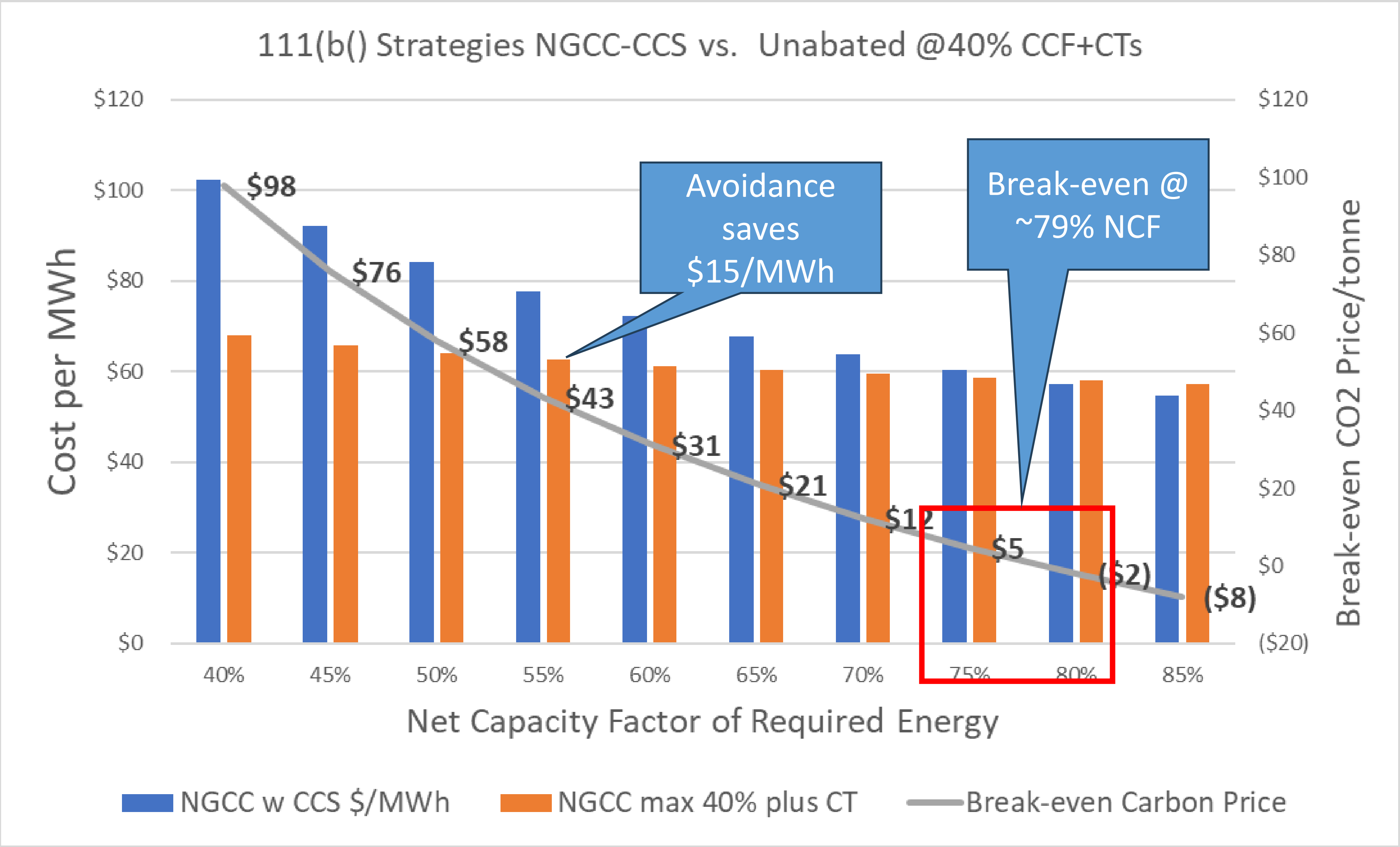
Challenges Facing Power Plants: Low NCFs

- NETL and other expert studies calculate capture cost for NGCCs and coal plants using an 85% Net Capacity Factor. I.e., plant is running at max capacity for 85% of all hours in the year. *Note: NETL's last study assumed >4 million tonnes/year captured, far larger than older concept of stack-gas bypass at ~1.6 million tonnes/year, leading to theoretical scale economies.*
- As a factual matter, only a handful of unabated NGCCs or unabated coal plants run at or near 85% NCFs. (3,000MW coal >85%; 1,500MW gas > 85%). Twice as many plants run <50% NCF as run at 50-85% NCF. **Absent state or federal policy changes, CCS-abated plants will also run at low capacity factors → far fewer tons to spread costs over.**
- Policies: Include **CCS as eligible for states' RPS**; require some % of low-carbon MW to meet states' utility reliability requirements.
- If plant is owned by a regulated utility, in the rate base, benefitting from its low capital cost, low NCFs still have a rate impact.

	NGCC Power Plant (Ratebased)	Coal-Fired Power Plant (Ratebased)
85% NCF	**~$123/tonne** CO_2 (retrofit) • $38/tonne > §45Q @ $85/t • Rate impact of **+$13/MWh**	**~$96/tonne** CO_2 (retrofit) • $11/tonne > §45Q @ $85/t • Rate increase of +10**/MWh**
40% NCF	**~$212/tonne** CO_2 • $127/tonne > §45Q @ $85/t • Rate impact of **+$45/MWh**	**~$162/tonne** CO_2 • $77/tonne > §45Q @ $85/t • Rate impact of **~$73/MWh**
Tonnes/Mwh captured	0.35	0.94

Easy to Avoid Triggering New EPA 111(b) Regs for Greenfield NGCCs

- New (a.k.a. greenfield NGCCs required to abate emissions to CCS levels (90% capture) if NGCC runs >40% NCF.
- But utility (and its regulators) may place zero financial value on reduced GHG emissions.
- If so, instead of a greenfield NGCC-CCS, it is likely cheaper to (i) build a greenfield unabated NGCC and (ii) run old simple-cycle turbines more frequently to avoid exceeding 40% on the unabated NGCC.
- A carbon price would meaningfully change result. (Declining grey curve starting at a $98 carbon price w/ 40% NCF, breaking even to zero carbon price between 75% and 80%.



What Would Help? Method Used [Backup Info]

- On the preceding pages 21 & 22, we used low equipment costs of $400/tpy and high equipment costs of $600/tpy. (Average = $500/tpy)
- For accurate assessment of policy/financing interactions, we ran full, multi-year corporate cash flow models. We *assumed* prevailing corporate debt interest rates (public), project finance debt interest rates (non-public, but can be estimated), corporate balance sheet investment hurdle rates for equity (non-public, but can be estimated), and project finance required equity returns (non-public).
- We then iterated (i.e., "solved for") various policies (dollar value of 45Q, length of 45Q, % ITCs) that would satisfy the requirements of those debt and equity funding sources. The 10.20% is the midpoint of those detailed runs.

**Technically: Post-tax, leveraged, Internal Rate of Return on original Equity investment. Tested case for a Corporate Owner that can fully use all tax deductions/credits in the year generated, with I.R.R. calculated over the life of §45Q collection period. Also tested a case for a standalone project that has no other businesses that generate significant federal taxable income.*

3.2: Insights from Barclays (file redacted at speaker's request)

Session 4: Basis for CCS Costs Internationally

4.1: CCS Costs: Key Learnings from Emissions Reduction Alberta's Carbon Capture Kickstart (CCK) Program

CCS Costs: Key Learnings from Emissions Reduction Alberta's Carbon Capture Kickstart (CCK) Program

March 5, 2025

INTERNATIONAL CCS KNOWLEDGE CENTRE

Shannon Timmons

Director, Technical Services

Accelerating the path to net-zero emissions

The International CCS Knowledge Centre is leading the world to a sustainable future by sharing insights and expertise on carbon capture and storage (CCS) and other solutions to address climate change.

We are independent, trusted advisors with unparalleled experience developing CCS projects, fostering collaboration and the exchange of knowledge to cut greenhouse gas emissions and achieve global net-zero goals.

Agenda

- Background
- Levelized Cost of Capture and Levelized Cost of CO_2 Avoided
- Methodology and calculation approach
- Results
- Cost reduction considerations
- Conclusions

Background

INFORMATION CURRENT AS OF JULY 1, 2024.

CCK program launched in 2022, funded by ERA in collaboration with a parallel program funded by NRCan.

11

Support 11 FEED studies to advance CCS projects in Alberta, targeting operational status by 2030.

\$40M for 11 FEED/pre-FEED studies

24 MT annual reductions -> approaching 10% of Alberta's GHG emissions

27

Covers 27 facilities in oil & gas, power, cement, forestry, and fuels & chemicals

Project details anonymized; data grouped into oil & gas, power generation, and materials production sectors.

Effect of Incentives on Technology Selection

- CCK program projects aiming for 2030 GHG reductions primarily chose liquid amine technology, with limited evaluation of lower-TRL options.
- Maximize benefit of CCUS tax credit and minimize technical risk.
- Incentives in Canada target capital costs, no incentives for operating expenses.
- Investment in next-gen lower TRL carbon capture could reduce costs and expand applications over a longer term.
- Longer term, a phased approach that balances cost and technology readiness could be undertaken.

LCOC & LCOA

The **Levelized Cost of Capture (LCOC)** and the **Levelized Cost of CO_2 Avoided (LCOA)** is the average dollar price per tonne of CO_2 required during the plant's operational life to meet all capital, operational, and maintenance costs.

LCOC considers all CO_2 captured, which includes CO_2 produced from the host facility flue gas, and any CO_2 produced due to the operation of systems that support carbon capture (ie: CO_2 from an auxiliary boiler or a combined heat and power plant)

LCOA considers the amount of CO_2 that is reduced, or "avoided", in the host facility's CO_2 emissions before and after the implementation of carbon capture.

Program	Current Program Emissions ($MtCO_2e/yr$)	Program Captured Emissions($MtCO_2e/yr$)	Program Reductions ($MtCO_2e/yr$)	% of Baseline Emissions Reduced
Total	29.4	29.6	25.3	86

Why are the LCOC and LCOA Important?

- The LCOC and LCOA is an important metric in determining whether or not to move forward with a project. Using the LCOC and LCOA to assess a project is a fundamental step taken in analyzing CCS projects.

- Allow for comparison of different capture technologies and projects. It allows for these comparisons regardless of unequal life spans, differing capital costs, size of the projects, and the differing risk associated with each project.

Methodology and Calculation Approach

Calculator was developed based on the NETL Levelized Cost of Electricity Method*

Scope of study was capture only, excluded the transportation and storage.

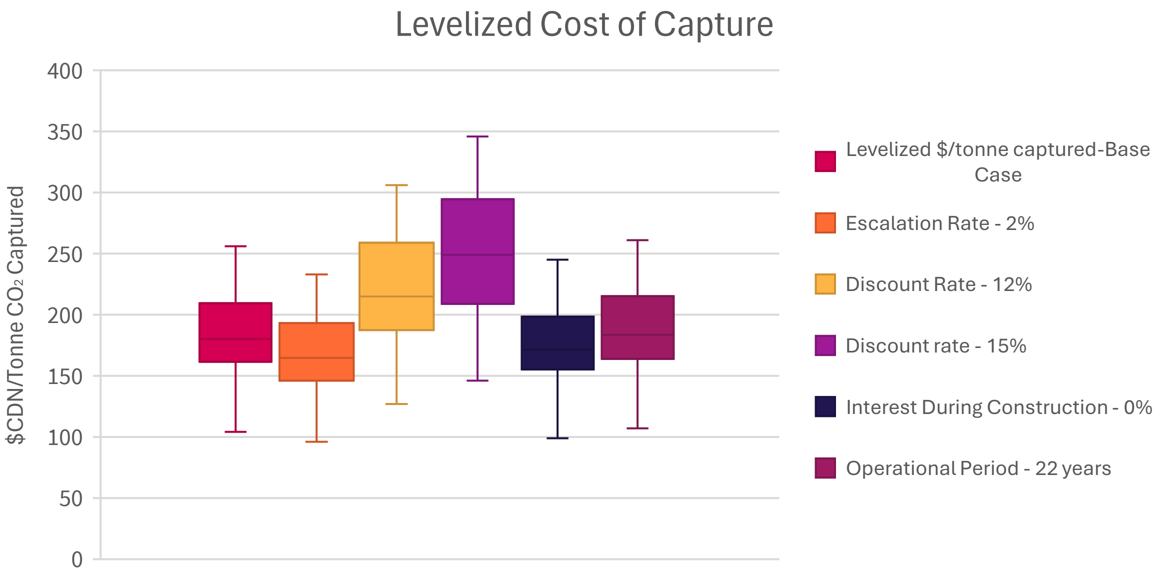
Important that the boundary limits were consistent.

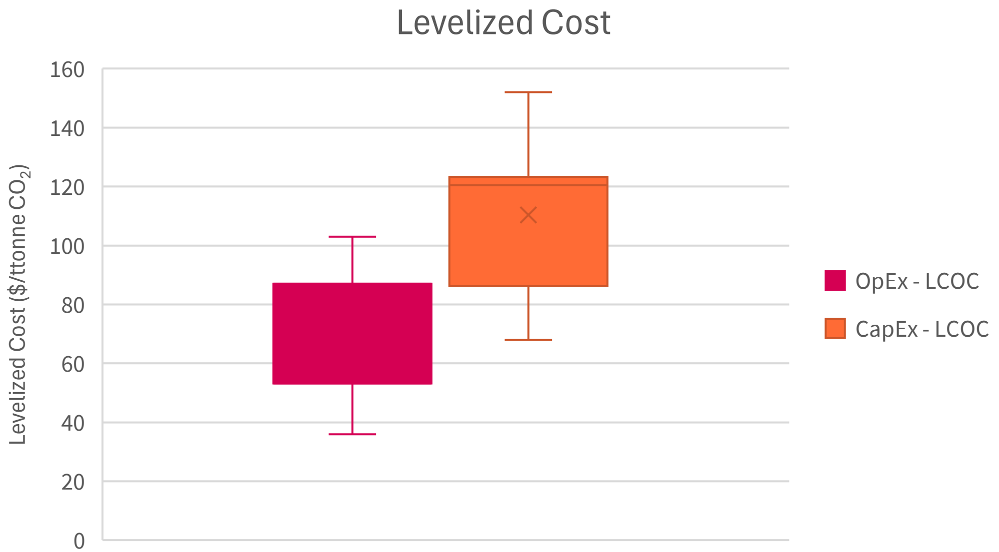
KEY COMPONENTS OF BASE CASE:

- Construction of the capture plant was set to begin in 2028 and finish commissioning by the end of 2030.
- Capital cost distribution 2028/2029/2030 – 20%, 50%, 30%.
- Escalation of capital costs – 3%.
- Escalation of fixed and variable O&M costs - 3%.
- Discount Rate (defined as the weighted average cost of capital) - 8%.
- Operational Period - 25 years.
- Proponent inputs: Overnight CapEx and OpEx, and CO_2 captured and avoided volumes.

*QUALITY GUIDELINES FOR ENERGY SYSTEM STUDIES Cost Estimation Methodology for NETL Assessments of Power Plant Performance, Sept 2019

Levelized Cost of Capture





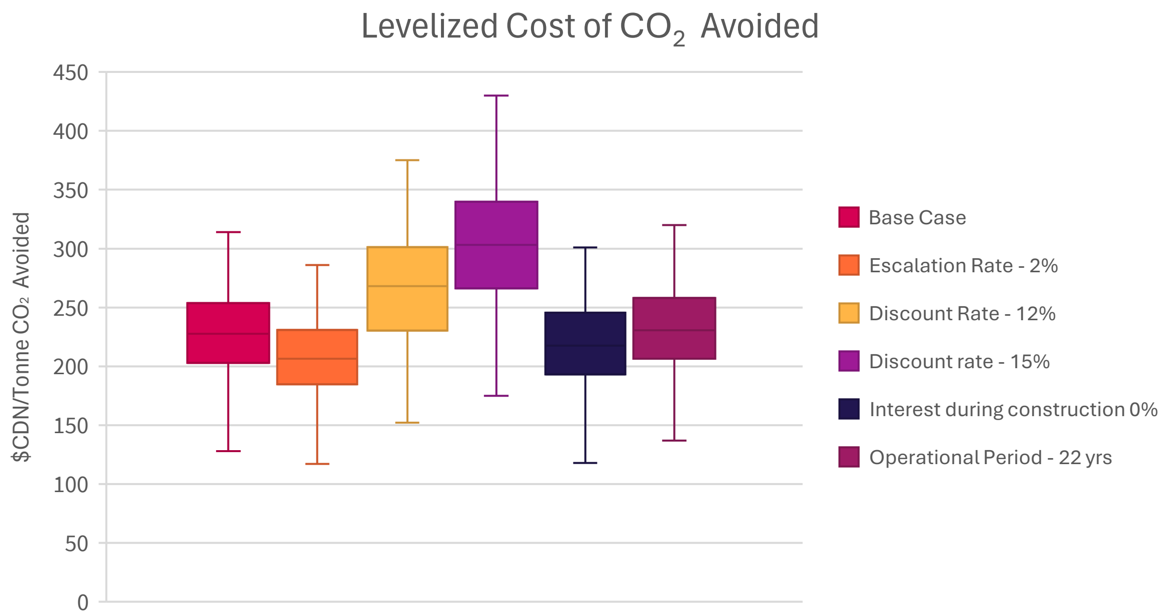
BASE CASE:

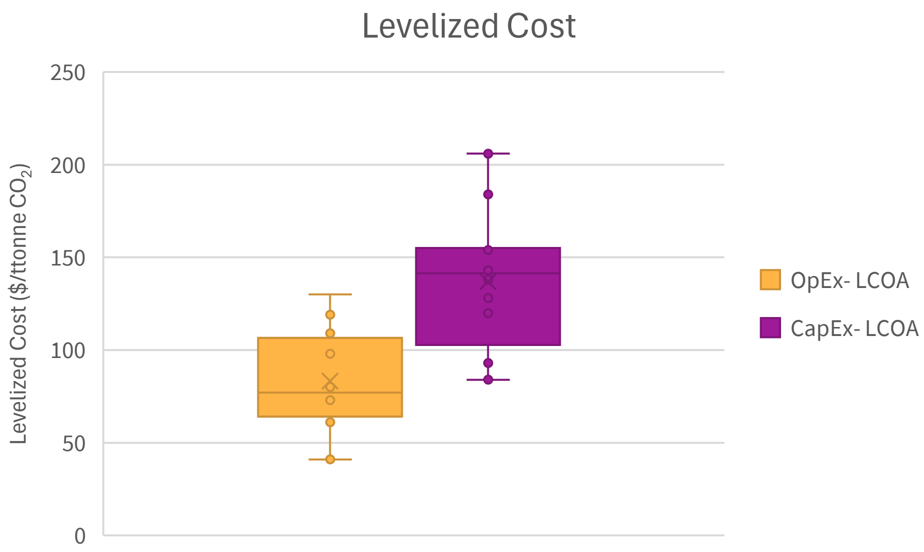
- Levelized OpEx = \$36 – 103 CDN/tonne CO_2
- Levelized CapEx = \$68 - 152 CDN/tonne CO_2
- LCOC = \$104 – 256 CDN/tonne CO_2
- Using user inputs: LCOC = \$126 – 282 CDN/tonne CO_2

- Discount rate has a large impact on LCOC and LCOA.
- Levelized cost was made up of 62% CapEx, and 38% OpEx.

From NETL Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity: NGCC at 90% capture: \$93 - \$101 CDN (2024)

Levelized Cost of CO_2 Avoided



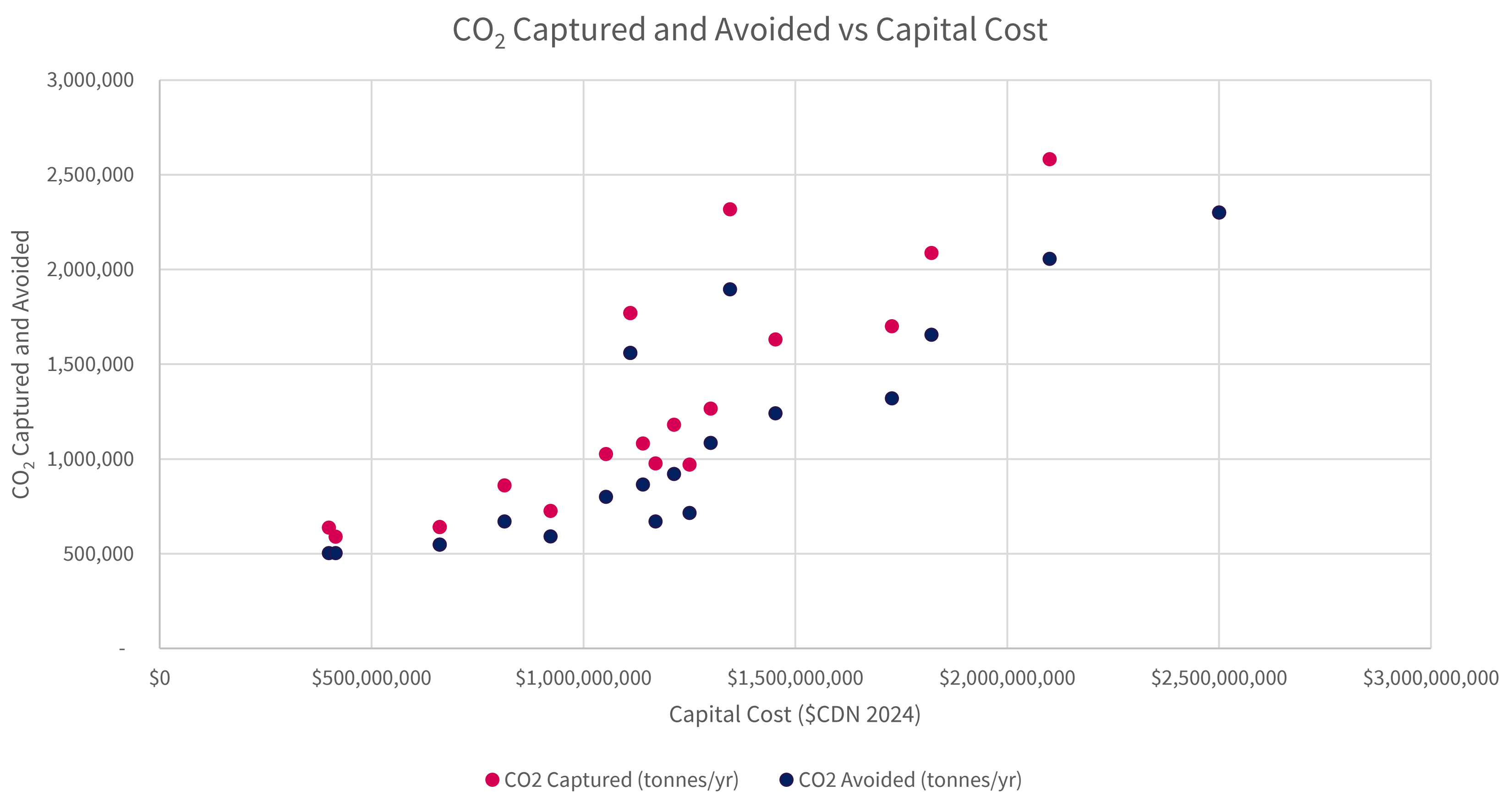


- The levelized cost of CO_2 avoided was approximately 20% higher than LCOC.

BASE CASE:

- Levelized OpEx= $41 – 130 CDN/tonne CO_2
- Levelized CapEx= $84 - 206 CDN/tonne CO_2
- LCOA = $124 – 314 CDN/tonne CO_2

CO_2 Capture and Avoided Volumes vs Capital Cost



Cost Breakdown

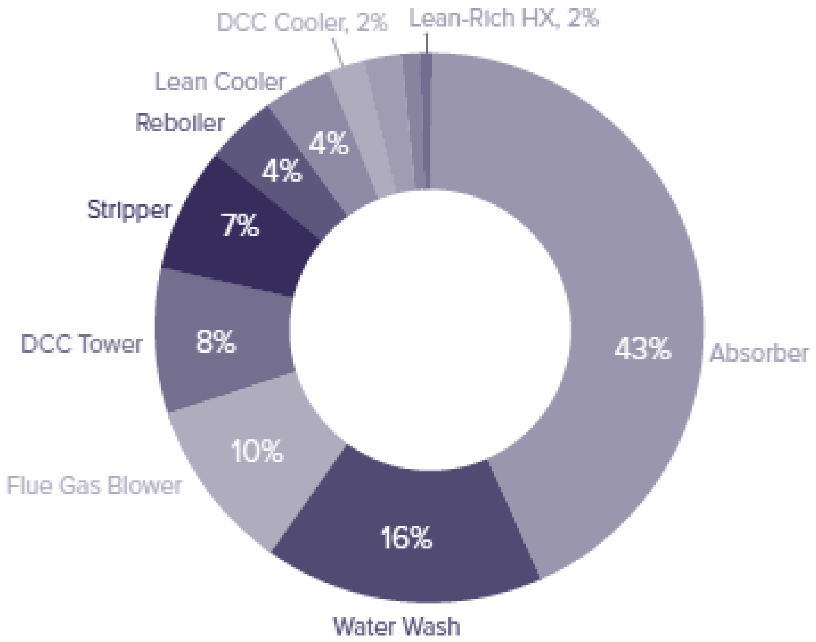


Figure 1 – Breakdown of capital costs of a typical 90% capture MEA plant.

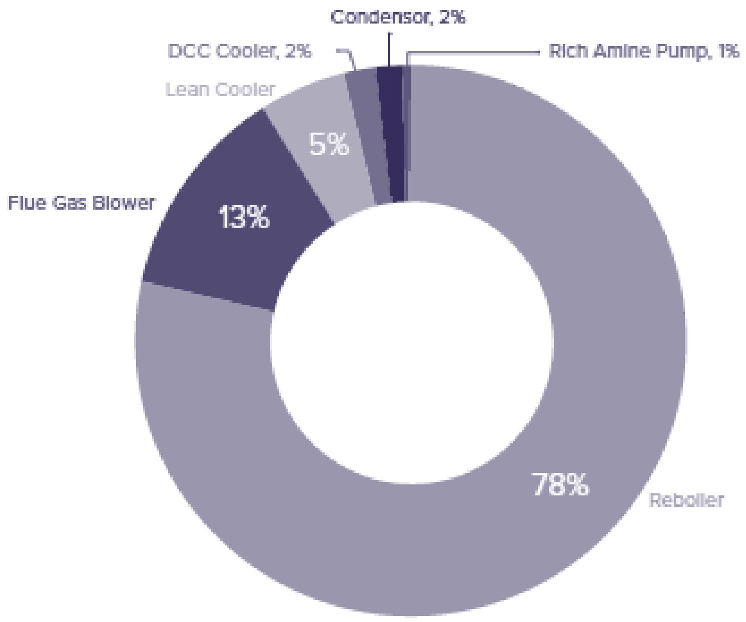


Figure 2 – Breakdown of variable operating costs of a typical 90% capture MEA plant.

Source: Advancements in CCS Technologies and Costs Report Jan 2025, GCCSI

Cost Reduction Considerations

Flue gas characterization of the flue gas for CCS applications

Evaluation of pretreatment of flue gas to optimize the performance of the carbon capture system

Sufficient redundancies built into the capture system

Evaluating utility usage and costs

- Influences technology selection
- Electric vs steam driven compression
- Air cooling vs water cooling vs hybrid cooling
- Combined heat and power plant for steam and power requirements
- Optimizing the operating conditions of the regenerator and CO_2 compressor

Modularization

Flue gas recirculation

Conclusions

A LCOC and LCOA calculator was developed and will be available for public use.

LCOA is approximately 20% higher than LCOC. Discount rate has a significant impact on LCOC and LCOA.*

OpEx accounts for 38% of LCOC, CapEx account for 62%.*

Many different cost reduction strategies and techniques are being evaluated at the project level to optimize CapEx and OpEx.

Through this initiative, knowledge has been shared from multiple projects, while maintaining individual project confidentiality.

Upon completion, all projects will publish public reports summarizing FEED outcomes, including costs and emissions reductions.

*Based on results from the calculator.

Questions?

INTERNATIONAL CCS KNOWLEDGE CENTRE

Thank You

Visit our website for more information:

ccsknowledge.com

Contact us by email:

info@ccsknowledge.com

Follow us on X:

@ccsknowledge

INTERNATIONAL
CCS KNOWLEDGE
CENTRE

4.2: Costing CCS for a Modelling Study

a) Costing CCS for a modelling study

B) Modelling Study Results

Dr Geoff Bongers

Gamma Energy Technology

Adjunct Professor @ University of Queensland

Costing CCS for a modelling study

Methodology based on the Australian Power Generation Technology report (2015).

The source data and its granularity has fundamental impact on how to translate the data.

https://www.powerfactbook.com/downloads/energy-reports

Costing CCS for a modelling study

Factors considered

IF and when the base data allows…
then we use all the options…
else is just 1 &2

1. Currency exchange rate
2. Labour productivity factors
3. Crew rates
4. Material cost factors

	Hunter Valley vs. USGC			
Discipline	**Labour productivity factor**	**Crew rate factor**	**Material cost factor**	**Currency exchange rate (A$:US$)**
Civil	1.40	1.49	1.20	1.30
Electrical bulks	1.40	1.52	1.16	1.30
Electrical equipment	1.40	1.70	1.08[a]	1.30
Insulation	1.40	1.65	1.02	1.30
Instrumentation and controls	1.40	1.70	1.08[a]	1.30
Mechanical equipment	1.40	1.87	1.08[a]	1.30
Piping and valves	1.40	1.80	1.07	1.30
Concrete	1.40	1.50	1.50	1.30
Structural steel	1.40	1.55	1.13[b]	1.30

Costing CCS for a modelling study

Currency ☹

Australian to United States Dollar

- Pick a number… any number

- P.S. I’m an Australian who can’t afford US beer this week… just say’n

Costing CCS for a modelling study

Regional Examples

Factor	Hunter Valley (reference)	vs. Hunter Valley Queensland	Victoria	Western Australia (south-west)
Labour productivity	1.00	1.21	0.93	1.00
Weighted average crew rate	1.00	0.92	1.07	0.89
Material cost				
Civil	1.00	1.22	1.00	1.29
Concrete (complete)	1.00	1.14	1.06	1.14
Balance of equipment and materials	1.00	1.02	1.00	1.00

Crew rate factors	vs. Gulf Coast cities	vs. US average
Gulf Coast cities	1.00	0.51
US average	1.96	1.00
Sydney	1.84	0.94
Hunter Valley (see Section 19.8)	1.73	0.88

Costing CCS for a modelling study

CAPEX of key plant

Capex represent the average over the build period in the model to 2050.

Plant	Australian model (GenCost)		Japan model (Lazard)
	AU$/kW (raw data)	US$/kW (using 1.3 AU$/US$)	US$/kW
Nuclear	8,952	6,886	11,200
Onshore Wind	2,028	1,560	1,248
Utility PV	946	728	883
Coal-CCS	8,954	6,888	5,953
Gas-CCS	3,740	2,877	2,136

Data Sources

- GenCost (Australia)
  - Each year, CSIRO and the Australian Energy Market Operator (AEMO) collaborate with industry stakeholders to update GenCost. This leading economic report estimates the cost of building new electricity generation, storage, and hydrogen production in Australia out to 2050.
  - https://www.csiro.au/en/research/technology-space/energy/gencost
- Lazard LCOE+, 2023 (Japan)
  - Lazard regularly produce LCOE estimates for generation. We used the capex and opex data that went into those calculations, but not the LCOE itself.

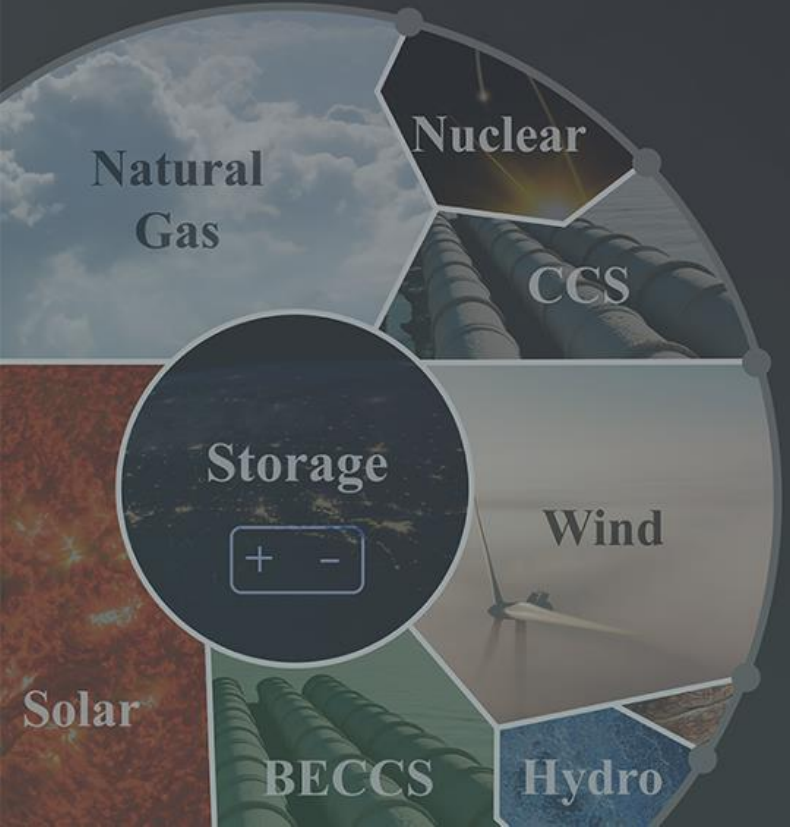
    https://www.lazard.com/research-insights/2023-levelized-cost-of-energyplus/

Dr Geoff Bongers
Gamma Energy Technology
Adjunct Professor @ University of Queensland

Mr Andy Boston
Red Vector

The Role of Low Emissions Dispatchable Power Generation in the Lowest Cost Net Zero System

Australia and Japan Case Studies IEA/COM/22/292



Project Overview

Organisations Involved

ieaghg

- The International Energy Agency Greenhouse Gas R&D Programme
- One of the IEA's Technology Collaboration Programmes
- Formed in 1991
- Funded by its 37 members
- Assesses the role of technologies in reducing greenhouse gas
- Employs the best academic institutions and technical consultancies from around the world to undertake detailed techno-economic assessments

REDVector

- Founded 2016 by Andy Boston
- Background in renewable development and power market optimisation
- Helps clients understand the future of energy in a decarbonised world
- Developer of MEGS (Modelling Energy and Grid Services)
- Technoeconomic modelling
- Optimised energy grids
- Founding partner of Heuristic Games used by universities and utilities for education and training
- Developed Modelling.Energy alongside Gamma Energy

Gamma Energy Technology
EXPERIENCE THINKING INNOVATION

- Founded in 2013 by Prof. Geoff Bongers
- Background in Mining, Aluminium and Energy
- Risk reduction for company processes and procedures
- Establishes and executes successful communication strategies with multiple stakeholders
- Crafting and leading the strategic direction of organisations
- Analysis of impact of decarbonisation on energy
- Developer and host of energy system primers: The Power Factbook

Scope of Work

Task 1: Literature Review

Task 2: Scenario Building and Modelling of Interdependencies

- Develop a methodology for scenario building
- Model interdependencies between power generation with CCS and other generation
- Use an energy system modelling tool that includes dispatchability and energy storage timescales from seconds to seasons.

Task 3: Sensitivities

- Reflect different degrees of intermittency of the system
- The extent of storage capacity may also be important

Task 4: Conclusions and Recommendations

The interdependency of dispatchable power plants with other power generation technologies is of primary interest

MEGS

Study used MEGS which was written to explore these issues:

- Can easily generate 100's of scenarios
- Takes constraints from second by second balancing into the modelling
- Specifically models storage over timescales of hours to months

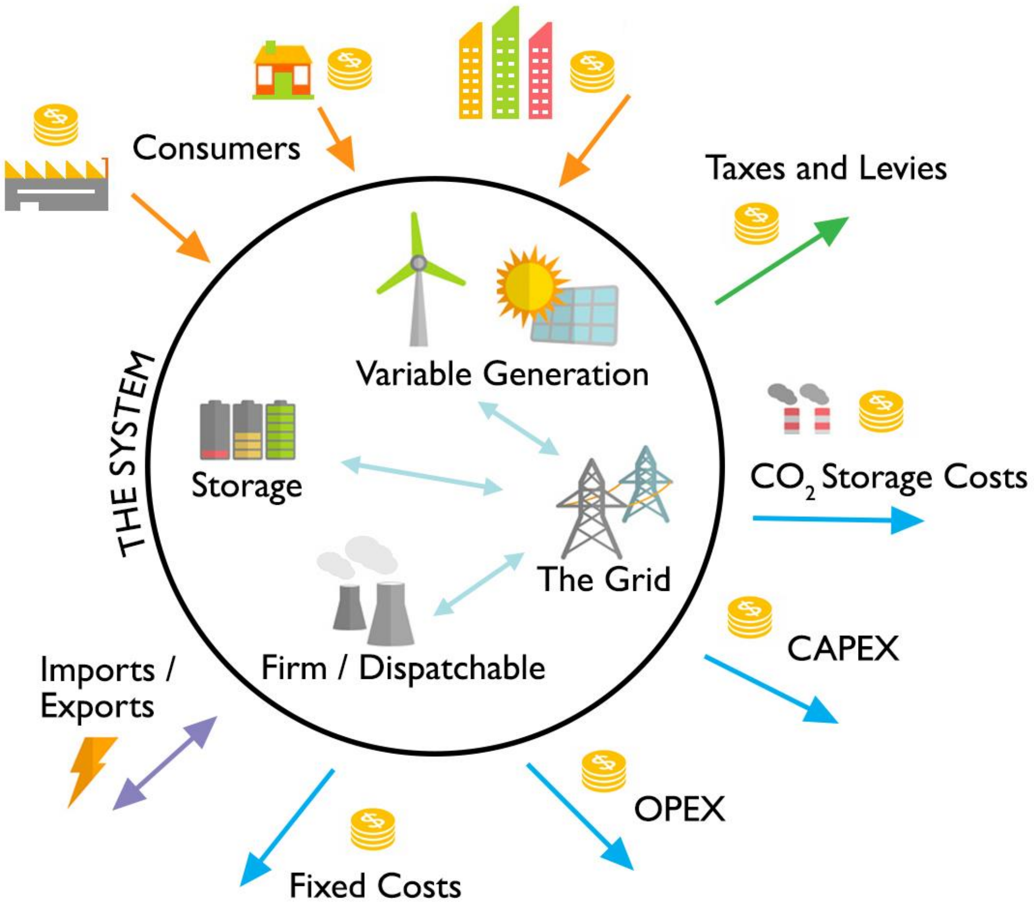
Each scenario explored different degrees of intermittency and storage. In addition, sensitivities explored:

- Hydrogen storage in Japan
- Nuclear renaissance in Japan
- Renewables push in Australia
- Peaking options

Total System Cost

- Power generation, storage and transmission assets are those shown within the ‘system’ circle, these are the physical elements of the system.
- Costs refer to any payments (blue & green arrows) that leave the electricity system
- The price paid by consumers (orange arrows) must cover all of these outgoings and hence is equal to the **Total System Cost**.

Whole System Model	Annual Energy Balance	MEGS	5 Minute / Hourly Scheduling	DC Flow Model	AC Transient Electrical Network Model
Broad Models					Detailed Models
Small No. of Scenarios Complex techno-economic models. Economics: whole energy system (heat, transport, power).	**Many Annual Scenarios** Simple spreadsheet solutions, includes economics.	**100s of Scenarios** Interconnect capabilities. Includes economics and system stability. Medium resolution	**A Daily to Yearly Resolution** Includes economics and unit dynamics (ramping, on-times etc).	**Simple Point in Time** Good estimate of system strength. Interconnect capabilities.	**Single Point in Time** Represents electrical engineering excellently: system fault stability, inertia requirements.



MEGS: Modelling Energy & Grid Services

MEGS is written to quickly see the effect of solutions on Total Systems Cost.
We use it to explore 1000's of scenarios for a decarbonised future and the here-to-there pathway

- Energy must balance. — **Conservation of Energy**
- There is sufficient supply of reserve and response services. — **Managing imbalances**
- There is sufficient inertia. — **Stability: time to react**
- There is sufficient reliable capacity to meet peak demand. — **Keeping the lights on!**

Whilst minimising short run cost

- **Fuel**
- **Carbon Storage**
- **Variable**
- **Start-up**

And optimising storage

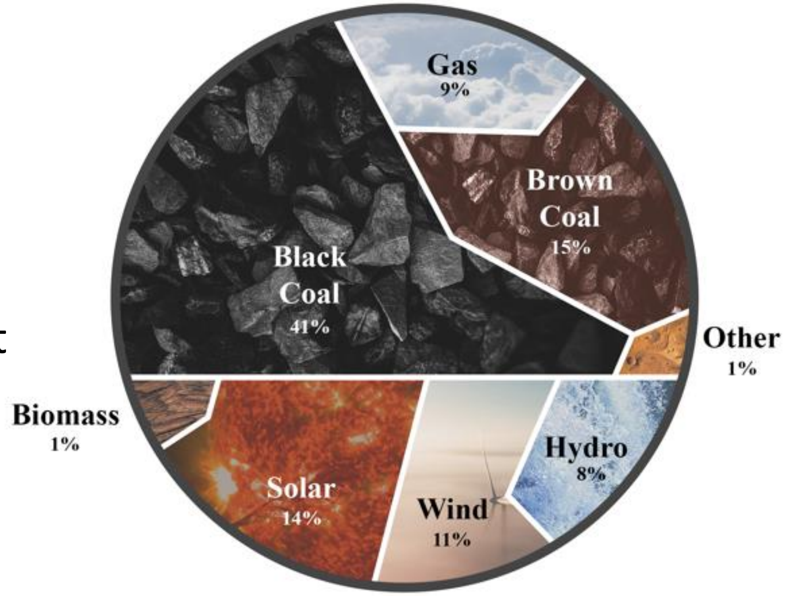
Adjusts capacity to maintain Loss of Load Hours

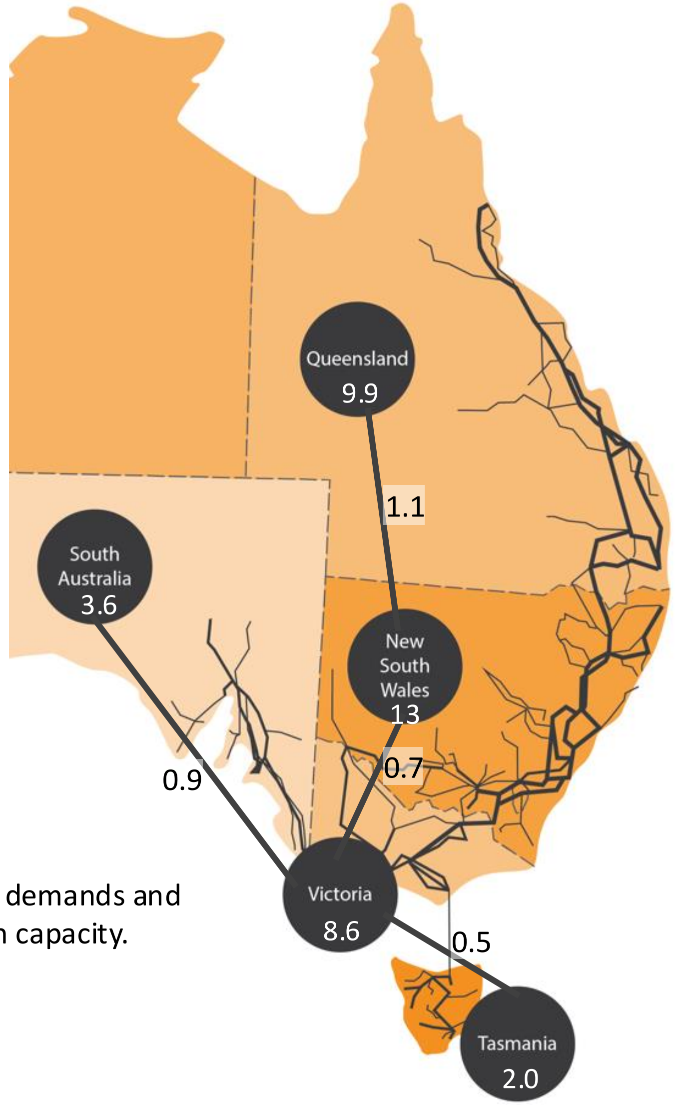
Australia

Australian National Electricity Market

Transmission:
- Five weakly interconnected regions
- All regions are interconnected by less than 25% of peak demand
- New interconnections to SA are being built and new DC cable to TAS proposed

Generation:
- Backbone of coal (56%)
- Renewables growing slowly (34%)
    - PV is growing, a lot is rooftop
    - Hydro is unlikely to expand much
    - Wind growth has slowed recently
- Gas important for peaking (9%)





Map illustrates peak demands and average transmission capacity.

NEM - Effect of CCS

Zooming in and excluding certain portfolios shows effect of constraining the system

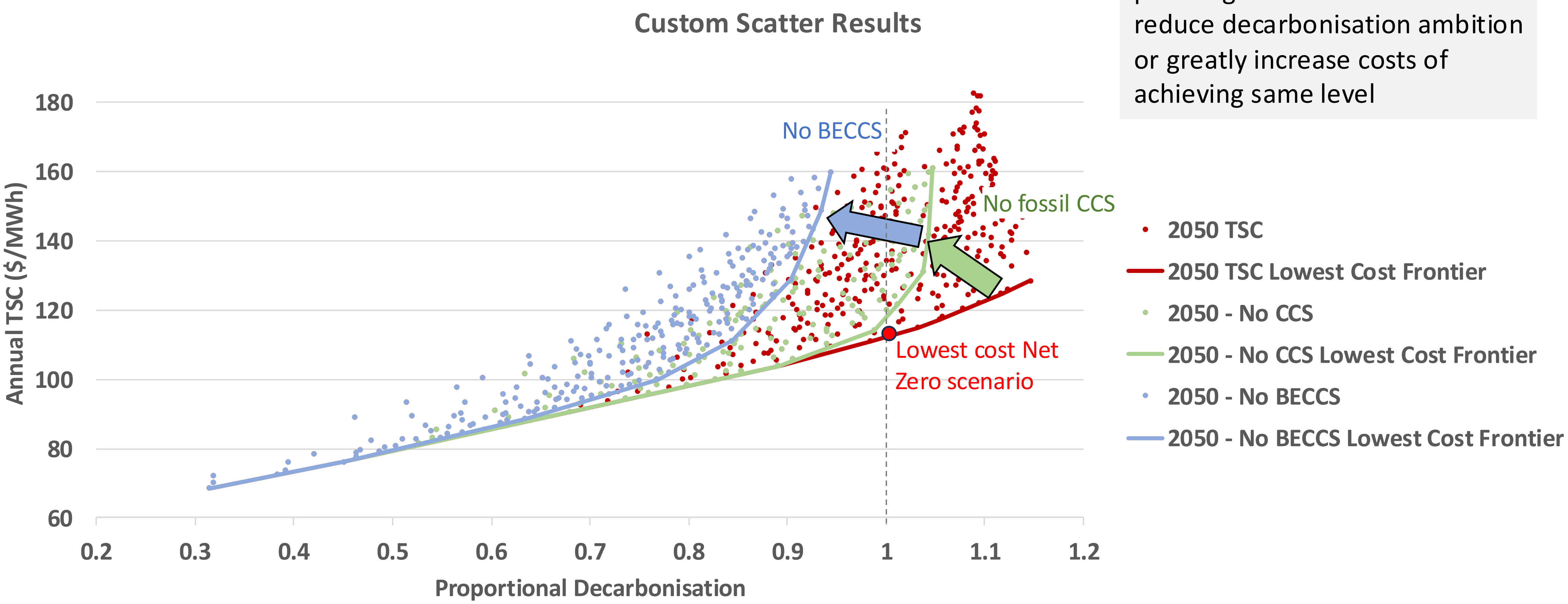
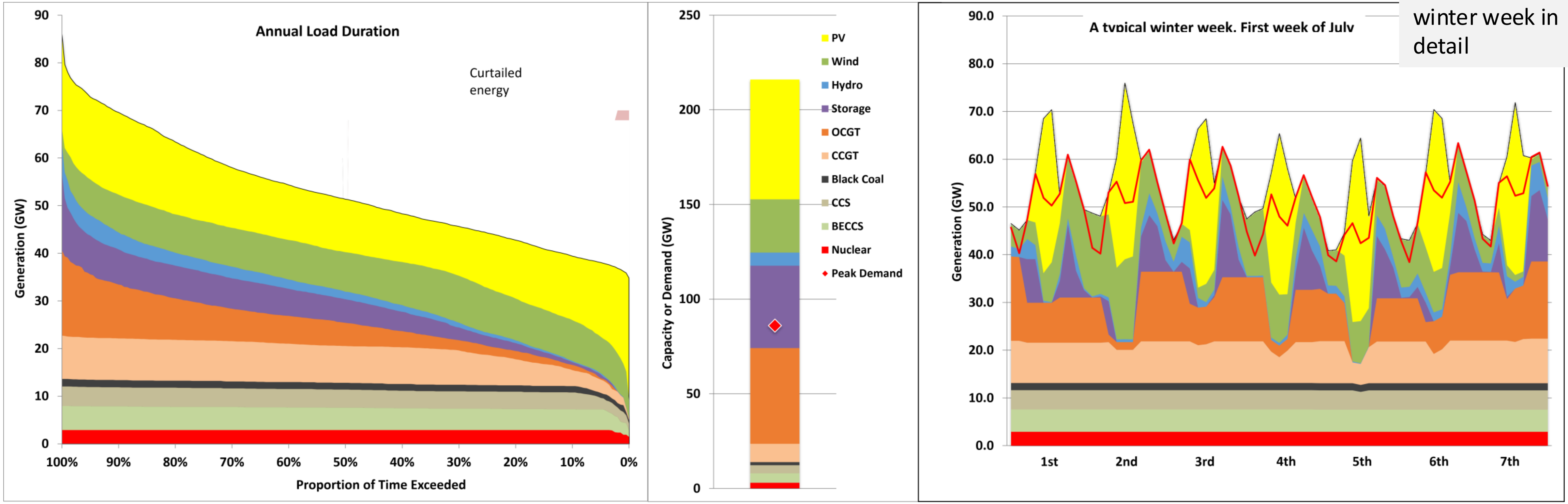


Chart shows effect of not pursuing fossil CCS or BECCS is to reduce decarbonisation ambition or greatly increase costs of achieving same level

Lowest Cost Net Zero Scenario

July 1-7, a winter week in detail



½ Renewables
¼ Firm Low Carbon Capacity
¼ Fossil Peaking (with BECCS soaking up the emissions)

Gas or coal CCS?

Two options for new fossil CCS are considered:

- CCGT with post combustion capture
- Supercritical coal with post combustion capture

LCOE can only be used to compare two options that deliver identical services, a safe assumption in this case. Gas is economic if price < 17.7 $/GJ

Cost and efficiency estimates for coal-CCS seem poor

- GenCost estimates that coal-CCS will cost nearly 2½ times the cost of gas-CCS.
- AEMO ISP assumes full load efficiency of just 25%, down from 41% for unabated coal.

Alternative scenario: coal-CCS capex 25% lower, Load factor 10% pts higher, coal efficiency 5% pts higher: Gas switching cost is then 11.3 $/GJ

Gas switching cost is probably around 11-18 $/GJ

Base Assumptions:

- WACC = 9%,
- Load Factor = 75% (from MEGS)
- CO_2 burial cost = 15$/t
- Capture Rate = 95%
- CO_2 Cost for slippage = 475 $/t

Base Scenario	**New CCGT-CCS**	**New Supercritical Coal-CCS**
CAPEX ($/kW)	3757	8965
Fixed ($/kW/yr)	17	81
Non fuel Variable OPEX ($/MWh)	7.5	8.2
Efficiency	40%	25%
Fuel Cost ($/GJ)	**17.7**	2.1 (62 $/tce)
LCOE ($/MWh)	[illegible]	**251**

Calculate

Implies

Match

Japan

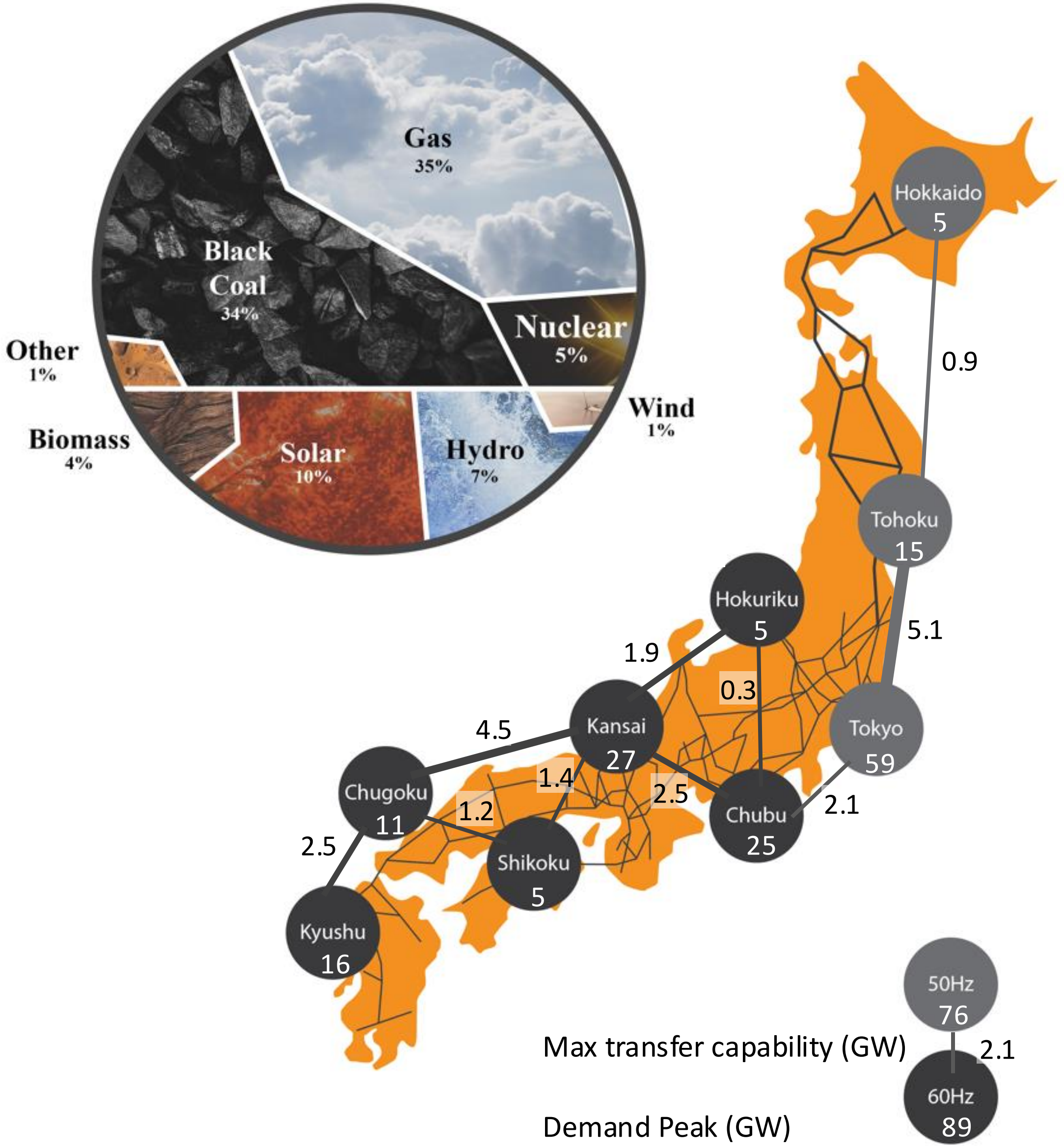
Japanese Electricity System

Transmission:

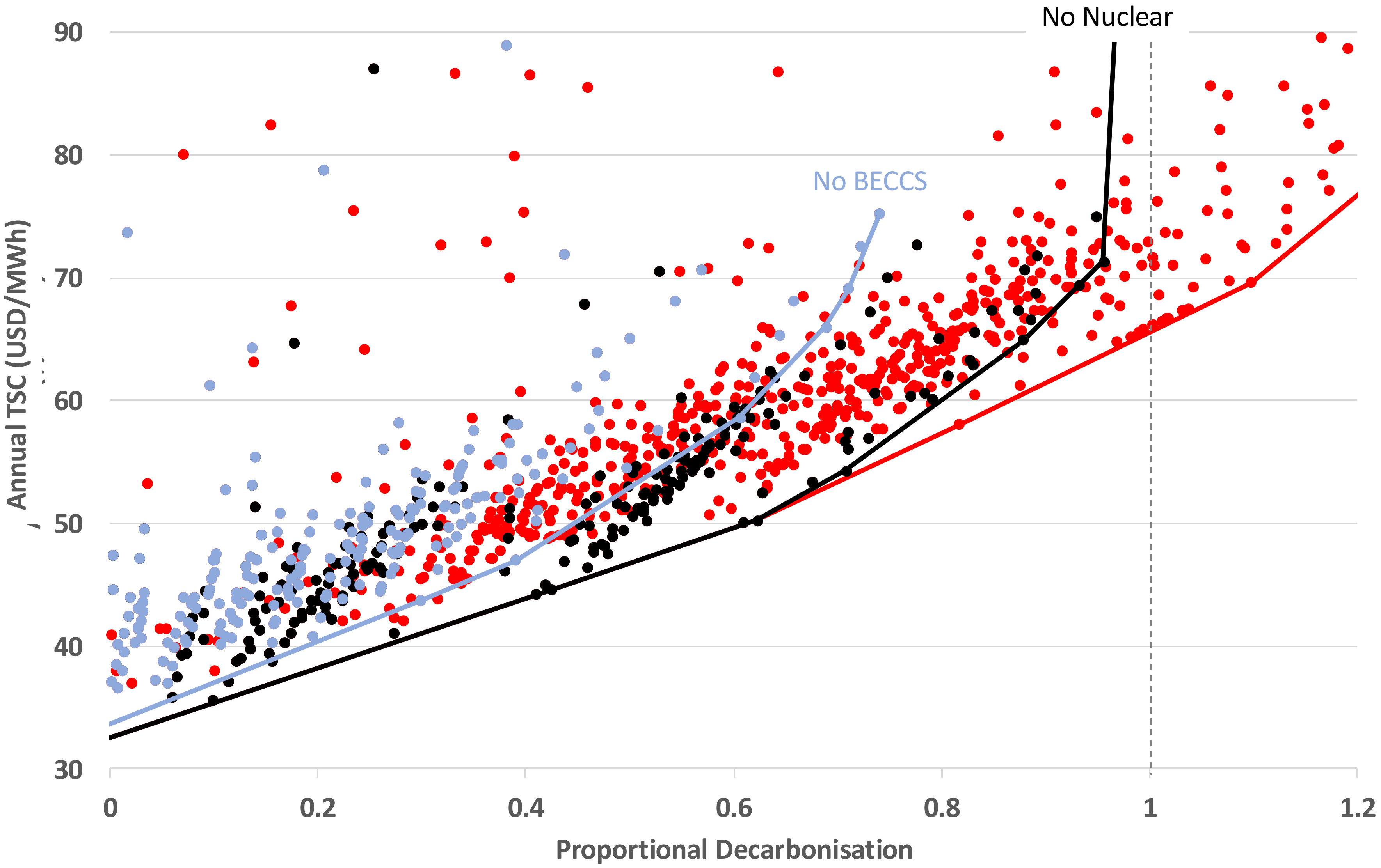
- Nine weakly interconnected regions (although not as weak as Australia)
- Five regions are interconnected by less than 25% of peak demand
- The interconnection between the two synchronous regions is very limited

Generation:

- Dominated by imported fossil generation (71%)
- Nuclear is making a comeback
  - 12 reactors have restarted
  - 5 have passed their review
  - 10 are under review
- Renewables deliver 22% of energy
  - PV is most important and growing
  - Hydro is legacy and unlikely to expand much
  - Wind is very small due to land use restrictions



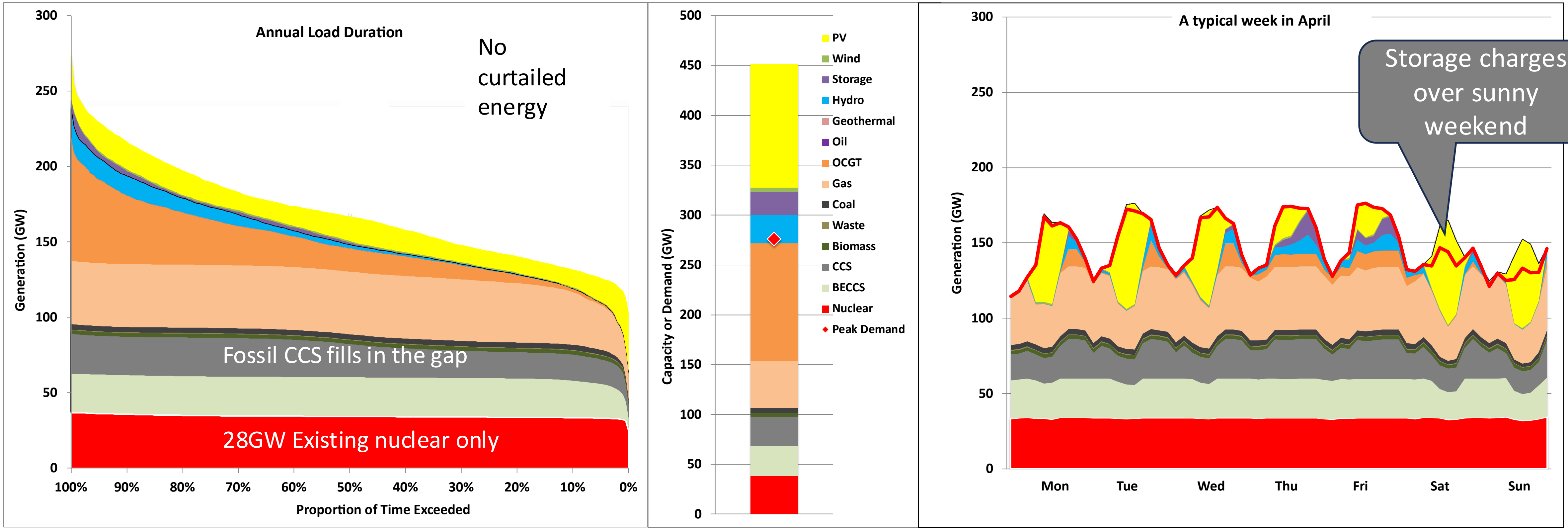
What If Key Technologies Were unavailable?



- While each “dot” or scenario is a competent grid they are not all the same cost.
- Omitting scenarios with nuclear results in more expensive solutions from about 60% decarbonisation.
- Disallowing BECCS costs more from the beginning of the decarbonisation journey!

No New Nuclear Optimal Scenario

For this scenario is was assumed that only existing nuclear was part of the solution
The lowest cost scenario was re-run at 2.5 hour resolution



Existing nuclear and Fossil CCS work together near baseload
Gas is mid-merit and peaking.
PV storage and hydro make a small but significant contribution

Emissions of 294 M tonnes are counteracted by BECCS capture and burial of 294 M tonnes

Summary

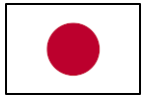
Summary and Remaining Questions

Summary

MEGS has been used to model the Australian NEM and Japanese electricity systems.

- More than 1,000 scenarios for each system satisfying the 2050 demand
- Examined combinations of Wind, Solar, Battery, Hydrogen storage, Fossil-CCS, BECCS, Nuclear and Gas
- All scenarios have a clear lowest cost frontier that gets increasingly steep as Net Zero is approached
- Net Zero cannot be achieved with renewables alone
- A lowest cost solution without BECCS is very expensive

- The lowest cost NEM has about half the energy coming from renewables, a quarter from peaking plant and a quarter from firm low carbon capacity such as nuclear, fossil-CCS and BECCS
- Delivering a 90% renewable grid in 2040 and only then lifting restrictions on CCS and nuclear raises cost by AU$10/MWh



- Hydrogen storage is very uneconomic Removing the nuclear option could cost Japan around US$10/MWh
- Lowest cost scenario has half the energy coming from firm low carbon capacity such as nuclear

Related literature: https://modelling.energy/publications

Session 5: Storage Cost Reduction

5.1: The "S" in CCUS: Cost Drivers for Onshore CO_2 Storage

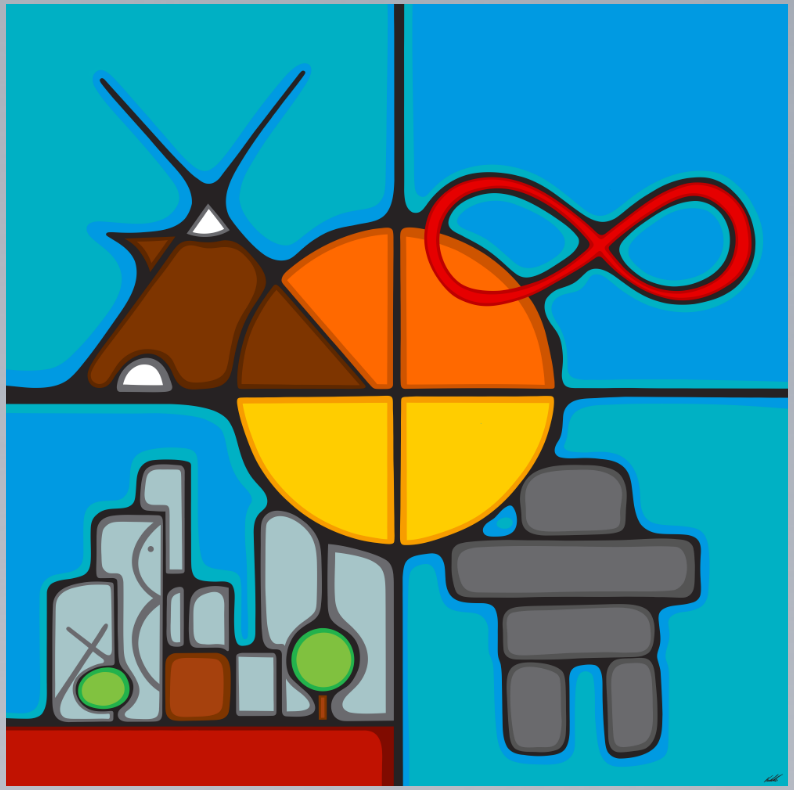
The "S" in CCUS

Cost Drivers for Onshore CO_2 Storage

Candice Paton | Vice President, Corporate Affairs
cpaton@enhanceenergy.com | www.enhanceenergy.com

enhance

Land Acknowledgement



Four Connections, by Kenneth Letander (Ojibway), licensed by Enhance

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 of Alberta, Districts 5 & 6.

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

Alberta Carbon Trunk Line Project/ Enhance Clive Sequestration Facility

With over 6.5 million tonnes of CO_2 permanently stored, the Enhance Clive Sequestration Facility is a world-class, safe and trusted CCUS project in Alberta, Canada.

With Enhance's storage, capture from two large emitter partners and common transportation infrastructure, the Alberta Carbon Trunk Line Project is one of the world's most successful CCUS projects to date.

1.5 MTPA

enhance

How much does it cost to store CO_2 in your project?

Hello, Enhance team! We're so excited to talk to you about our upcoming capture project. We'd love for you to store our CO_2.

Super! Tell us more about your project. What will your capacity needs be? When will your project be online?

We're going to be online in 2035, and have between 100,000 TPA and 1 MTPA. **But what we really need are your T&S costs so that we can get to our FID…**

…

enhance

ARTICLE 8: OBLIGATIONS

1. The Agreement Holder shall, in accordance with any relevant Enactments:

(a) pay all fees as may be prescribed by or under any relevant Enactments. Without limiting the generality of the foregoing, this includes payments into the Post-closure Stewardship Fund for all carbon dioxide injected into any part of the Location under this agreement;

(b) be responsible for the development of all carbon sequestration activities within the Location;

(c) establish rates to Clients which are fair and provide for reasonable cost recovery to the Agreement Holder for the relevant infrastructure services and activities. The Agreement Holder shall further provide information to enable Clients and Alberta to understand how rates are set;

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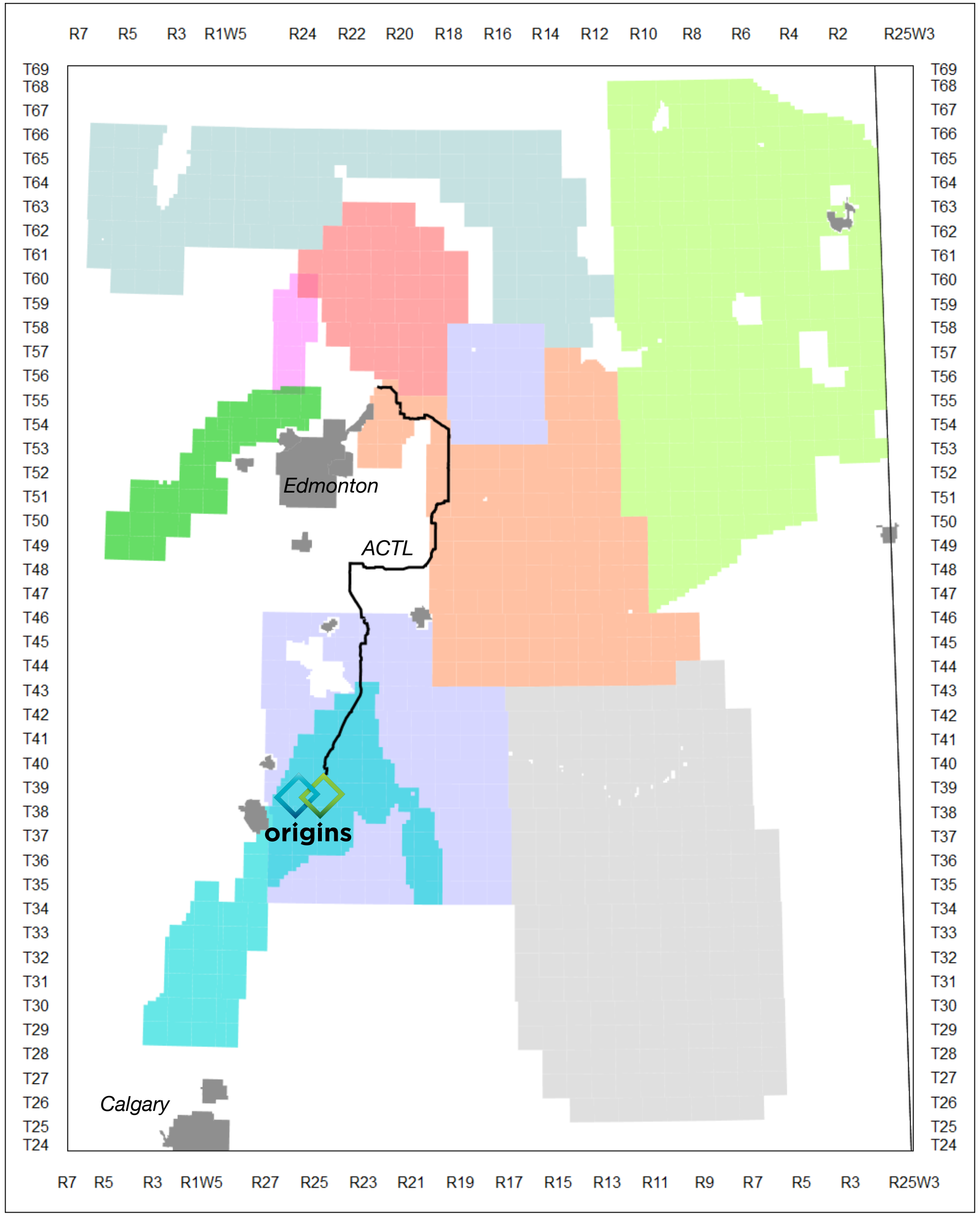
Reference: Government of Alberta: Carbon Sequestration Tenure

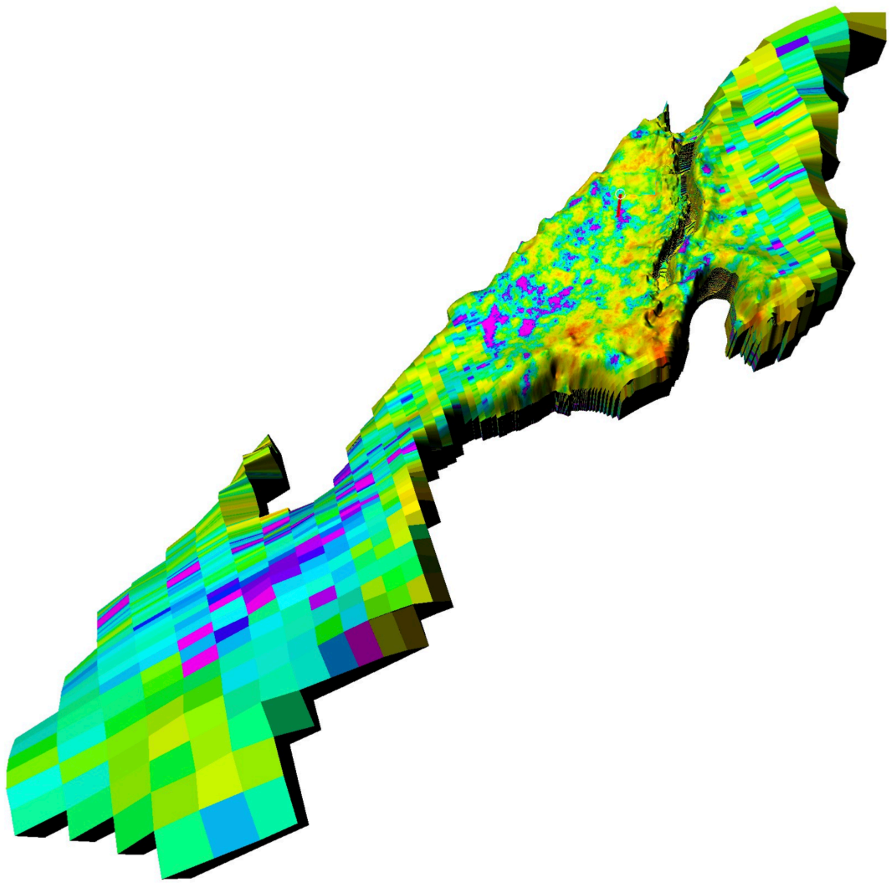
origins

Four key considerations for site selection:

- Containment
- Capacity
- Injectivity
- Induced Seismicity



1 Capacity



- What are the capacity requirements and where does your estimate of capacity come from?
- What is the long term outlook for the project? Do you need certainty this year… and for the next 49?
- What requirements might your jurisdiction impose on pore space? Royalties, etc. How is your commercial arrangement structured to accommodate future charges?

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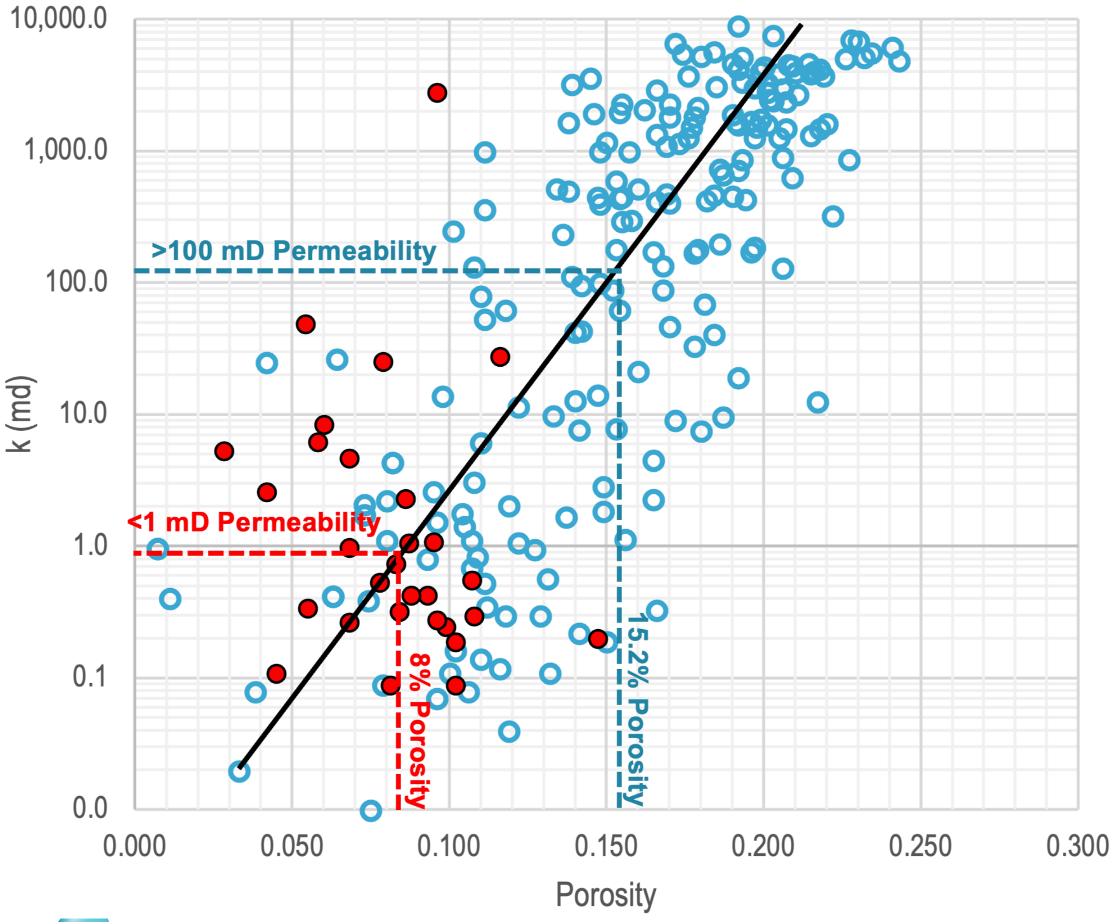
2 Injectivity



- How many wells are we drilling?
- Commercial agreements to share subsurface risk:
  - Availability: best efforts or "store-or-pay"
  - Contingency and maintenance considerations

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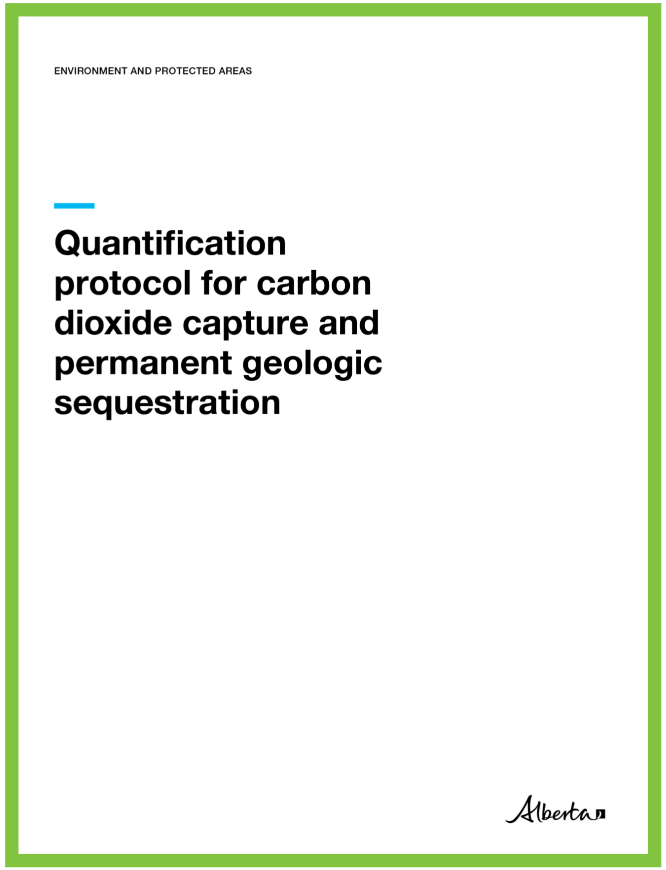
3 Containment


ENVIRONMENT AND PROTECTED AREAS

Quantification protocol for carbon dioxide capture and permanent geologic sequestration

Alberta

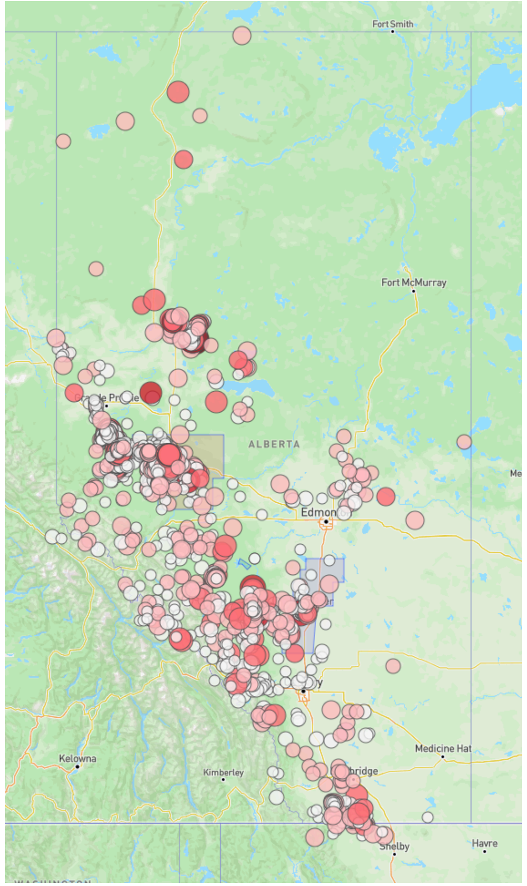
- Alberta CCS Protocol
  - Definition of a reversal:
    - The AER determines a loss of containment has occurred
    - The loss of containment cannot be remedied
    - An expert investigation determines … [CO_2] will reasonably leak into the atmosphere within 100 years of the occurrence…
  - Flexibility mechanisms
    - 3-year rolling average on injected CO_2
    - Increased discount factor

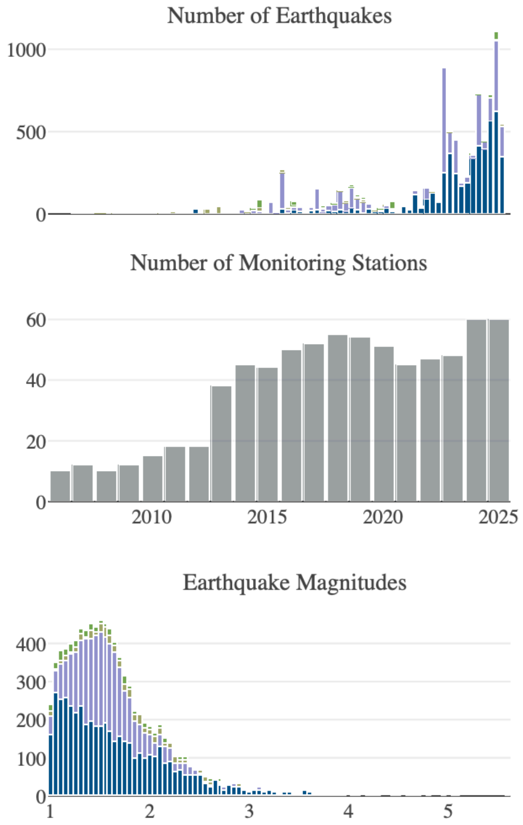
Liability

enhance

- Reference: Open Alberta: Protocol for Carbon Dioxide Capture and Permanent Geologic Sequestration

4 Seismicity





- What will the regulator require for monitoring of seismic activity?
- What are the consequences of any known or suspected induced seismicity?

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- Reference: [Alberta Geological Survey Earthquake Dashboard]

Framework

- Does a utility/tariff model for sequestration always make sense? Not necessarily.
- Effective costing of sequestration requires a discussion of risk and shared liability/obligation between capture, transport and storage partners.
- Flow-through and variability on costs that remain uncertain are difficult risks for non-operating entities to shoulder.
- Projects need to de-risk costs to get to FID – how does a sequestration partner provide appropriate costs?
  - Evaluation activities: technical work to de-risk “the Big 4”
  - Misalignment between the parties storing CO2 and generating credits: who is exposed to increased costs, who is exposed to the benefits?
  - Certainty in the regulatory system supporting CCS
  - Strong partnerships to find the balance of risk-sharing: best-efforts or performance guarantees (both capture and sequestration), take-or-pay models, rate-of-return models, credits and reversals

What are we hearing??

	Pipeline/Compression	Sequestration
Scope/Materials	Well-defined, low variability between projects, gated development process	Uncertain until technical evaluation is complete, can be highly variable between projects/areas
Injectivity/Allocation	Known quantities enter and exit the system, can be allocated using measurement	Known quantities enter the system, allocation must be done using data from upstream partners, first-in first-out methods required in the case of reversals
Capacity	Rate capacity is designed, but cumulative capacity is not an issue	Rate capacity is uncertain until technical evaluation is complete, cumulative capacity is similar to reserves, ultimately not known for years down the road
Tolls/Rates	Simple methodologies with flow-through costs, often transparent	May require bespoke methodologies based on shared risk between partners. Uncertain until technical evaluation and regulatory frameworks are set. Can change if government policies change.

enhance

- 15-year company history
- Founding partner of the ACTL Project
- Operator of 50% of Canada's CCS/ CCUS capacity
- Over 6.5 million tonnes permanently sequestered
- Carbon utilization and storage is our business

5.2: CCUS: Cost of Drilling in North Dakota

Critical Challenges. Practical Solutions.

Energy & Environmental Research Center (EERC)

CCUS
Cost of Drilling in North Dakota

8th IEAGHG CCS Cost Network Workshop

Houston, Texas

March 6, 2025

Wes Peck

Assistant Director for Subsurface Strategies

MAJOR COST DRIVERS OF A CCUS WELL

- Site preparation
- Mobilization
- Long-lead-time items (e.g., casing)
- Drilling
- Characterization

SITE PREPARATION

- Site selection
- Landowner agreement ($-$$)
- Site surveys
- Building the site
  - Pad and roadway

MOBILIZATION

- Distance.
- Number of loads.
- Time of year.

LONG-LEAD-TIME ITEMS

- Casing
  - Carbon steel (standard)
  - CRA material
- Wellhead
- Auxiliary gauges
  - Downhole gauges
  - Fiber optics
- Cement
  - Class G
  - Corrosion-resistant specialty blends

DRILLING

- Number of days and daily operating cost
- General drilling contractor (GDC)
- Rig
- Drilling fluid
  - Type and amount
- Rentals
  - Tank farm, housing, lights, loader, and others

CHARACTERIZATION

- Coring
  - Whole core – formation of interest as well as ~50 ft of overlying and underlying rock
  - Sidewall
- Logging
  - Advanced suite of geophysical logs
- Formation testing
  - Formation pressure testing
  - Fluid sampling
  - Stress testing
  - Injection test

WELL COST SCENARIOS
BASED ON NORTH DAKOTA CCS PROJECTS

COST SCENARIOS

- Scenario 1: One formation versus multiple formations of interest
- Scenario 2: Depth
- Scenario 3: Stratigraphic test well with intent to transition to a Class VI injection/monitoring well versus P&A stratigraphic test well
- Scenario 4: Completion

SITE PREPARATION AND RIG MOBILIZATION

Site preparation

- Landowner lease agreement
- Site surveys
- Building the site (pad, roadway, liner)

• Cost range

- $500,000–$1,400,000

Rig mobilization

- Distance
- Number of trucks needed
- Weather and road restrictions

• Cost range

- $350,000–$850,000

SCENARIO 1: ONE FORMATION VS. MULTIPLE FORMATIONS

One Formation		Three Formations	
Site preparation	$650,000	Site preparation	$650,000
Casing – combo of 13Cr (600’) and carbon steel	$430,000	Casing – combo of 13Cr (1800’) and carbon steel	$530,000
Rig mobilization	$500,000	Rig mobilization	$500,000
Drilling to 7000’	$3,800,000	Drilling to 7000’	$5,340,00
Characterization -Logging -Whole core (400’) -Formation testing and sampling	$880,000	Characterization -Logging -Whole core (400’) -Formation testing and sampling	$1,250,000
Total Cost 1 Formation	**$6,260,000**	**Total Cost 3 Formations**	**$8,270,000**

SCENARIO 2: 7000 FT VS. 14,000 FT

Depth 7000’		Depth 14,000’	
Site preparation	$650,000	Site preparation	$650,000
Casing – combo of 13Cr (600’) and carbon steel	$430,000	Casing – combo of 13Cr (600’) and carbon steel	$820,000
Rig mobilization	$500,000	Rig mobilization	$500,000
Drilling	$3,800,000	Drilling	$4,680,000
Characterization -Logging -Whole core (400’) -Formation testing and sampling	$880,000	Characterization -Logging -Whole core (400’) -Formation testing and sampling	$1,220,000
Total Cost TD @ 7000’	**$6,260,000**	**Total Cost TD @ 14,000’**	**$7,870,000**

SCENARIO 3: FUTURE CLASS VI VS. STRATIGRAPHIC TEST WELL P&A

Future Class VI Injection/Monitoring Well		Stratigraphic Test Well P&A	
Site preparation	$650,000	Site preparation	$650,000
Casing – combo of 13Cr (600') and carbon steel	$430,000	P&A	$270,000
Rig mobilization	$500,000	Rig mobilization	$500,000
Drilling to 7000'	$3,800,000	Drilling to 7000'	$3,800,000
Characterization -Logging -Whole core (400') -Formation testing and sampling	$880,000	Characterization -Logging -Whole core (400') -Formation testing and sampling	$800,000
Total Cost Future Class VI	**$6,260,000**	**Total Cost P&A**	**$6,020,000**

SUMMARY OF SCENARIOS 1–3

Cost Component	One Formation of Interest (TD at 7000')		Three Formations of Interest (TD at 7000')		Total Depth to 14,000'		Stratigraphic Test Well P&A	
Rig Mobilization	$	500,000	$	500,000	$	500,000	$	500,000
Site Preparation	$	650,000	$	650,000	$	650,000	$	650,000
Casing – Combination of 13Cr and Carbon Steel *P&A for Column 5	$	430,000	$	530,000	$	820,000	*$	-
Drilling	$	3,800,000	$	5,340,000	$	4,680,000	$	3,800,000
Characterization	$	880,000	$	1,250,000	$	1,220,000	$	800,000
Total	$	6,260,000	$	8,270,000	$	7,870,000	$	6,020,000

COST: CASING AND CEMENT VARIABILITY

- CRA casing (7” 32#) example
  - Carbon steel ~$50/ft
  - 13Cr ~ 2.5X
  - S13Cr ~10X–12X
  - 15–17Cr ~11X–13X
  - 22–25CR ~12X–20X
  - G3/Hastelloy ~22X–25X
- Cement
  - Class G ($105/bbl)
  - Latex blend ($200-$250/bbl)
  - Resin (~$2000/bbl)

SCENARIO 4: COMPLETION COST

- Tubulars
  - 6800’ of 4.5” 13Cr
  - ~$400,000
- Workover, cleanout, and installation
  - $15,000 a day
- Injection test
  - ~$1,000,000 per horizon
- CRA-resistant packer
  - ~$280,000
- Wellhead
  - ~$400,000
- Downhole gauge/monitoring
  - ~$600,000

ESTIMATED CCUS WELL COST COMPARISON

Cost Component	One Formation of Interest (TD at 7000')	Three Formations of Interest (TD at 7000')	TD at 14,000'	Stratigraphic Test Well P&A
Drilling	$ 6,260,000	$ 8,270,000	$ 7,870,000	$ 6,020,000
Completion	$ 2,940,000	$ 5,120,000	$ 3,530,000	$ -
Total	$ 9,200,000	$ 13,390,000	$ 11,400,000	$ 6,020,000

Wes Peck
Assistant Director for Subsurface Strategies
wpeck@undeerc.org
701.777.5195

Energy & Environmental Research Center
University of North Dakota
15 North 23rd Street, Stop 9018
Grand Forks, ND 58202-9018

www.undeerc.org
701.777.5000

THANK YOU

Critical Challenges. Practical Solutions.

EERC | UND UNIVERSITY OF NORTH DAKOTA

Critical Challenges. Practical Solutions.

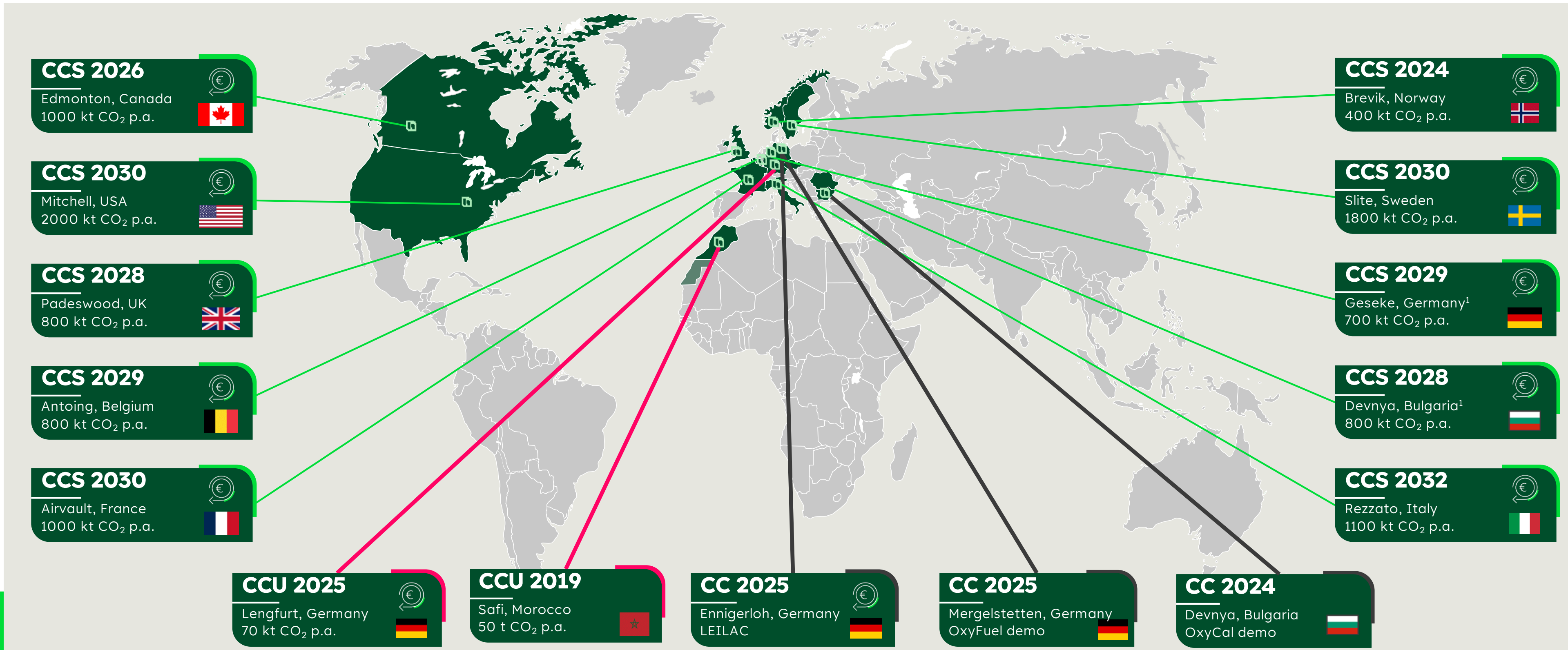
5.3: Levelised Cost of CO_2 Storage

Levelized cost of CO2 Storage

Houston| IEAGHG | Jan Theulen & Ole Engels
March 05, 2025

Heidelberg Materials

The published CCUS portfolio of Heidelberg Materials



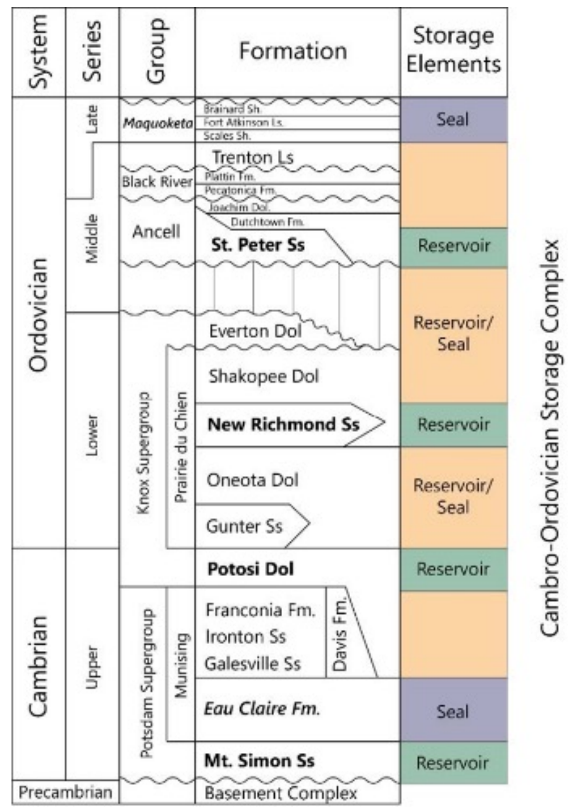
We will capture 10 Mt CO_2 cumulatively and invest 1.5b€ by 2030

€ Subsidies required

1 - EU funded projects

CCUS at Heidelberg Materials is not anymore a paper exercise!

2D seismic acquired in 2024 – Mitchell/Indiana

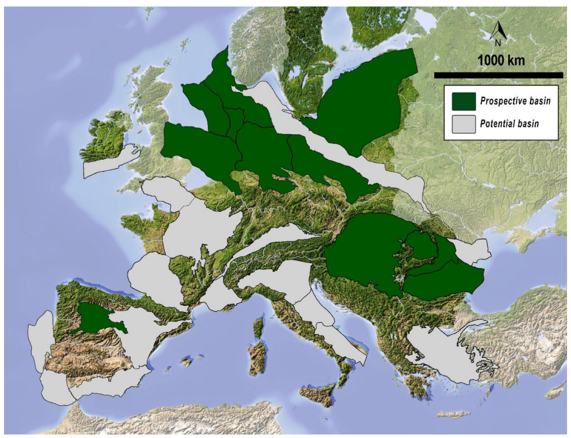


CCUS at Heidelberg Materials is not anymore a paper exercise!

2025 - Ongoing exploration drilling operations – as we speak!

CO2 Storage is not built equal – Properties matter

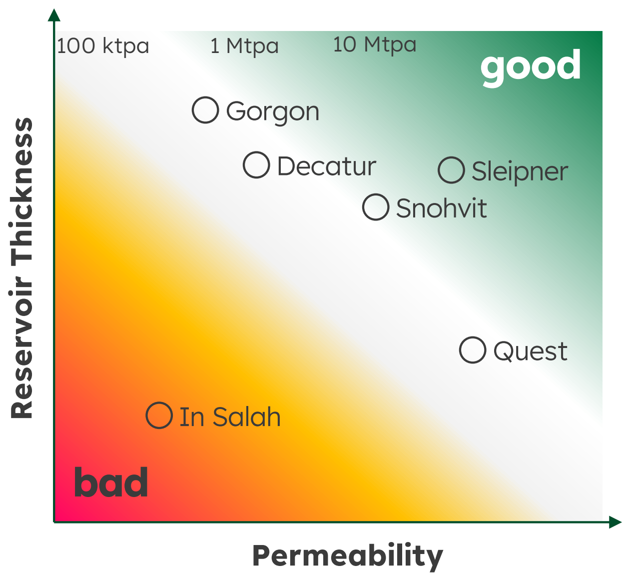
Capacity



Europe (ex UK) 72 GtCO2

Source: Global CCS Institute

+ Injectivity



Storage Properties can drive significant economic opportunities

- A combination of storage capacity and injectivity
- Storage efficiency
- Storage depth
- Multiple horizons

CO2 Storage – Cost Modeling Exercise

	High	Low
Injectivity (per well)	1.5 MTPA	0.2 MTPA
Storage Capacity	150 MT	50 MT

Not included in the "storage"-scope:

- Receiving terminal or ship-unloading facilities
- Trunkline from terminal to injection wells

Onshore

Devex:
- G&G studies
- Seismic
- Appraisal wells
- Legacy wells

Capex:
- Injection & Monitoring wells
- Interconnecting pipelines
- Boosters
- Surface utilities (power, water, control equipment)

Opex:
- Energy consumption
- MMV
- Liability costs

Offshore

Devex:
- See onshore
- Platform designs

Capex:
- See onshore
- Platforms adjustments

Opex:
- See onshore

Levelized Cost of Storage

Onshore vs Offshore Storage [€/t CO2]

Green = ONSHORE

Blue = OFFSHORE

To learn details from this slide pls contact:
Jan.Theulen@HeidelbergMaterials.com
Ole.Engels.Ext@HeidelbergMaterials.com

Key Observations:

- Real-world data
- Offshore with a 4x premium over onshore storage *(however best offshore storages close to cost of inefficient onshore stores)*
- Attractive onshore business models
- Maintainability & Control
- Environmental & Social considerations

All calculations:

8% WACC + 15 yrs depreciation

YR 2022 cost basis

Key take aways

- **We are constructing** CCS and CCU projects, some of them are end-to-end
- **We have invested** into building our CO_2 Storage knowledge, and our learnings help us to proactively drive our bottom line
- **We are excited** about a future growing acceptance of Onshore Storage options, worldwide

Breakouts

Breakout 1: International CCS Drivers

6.1: International Drivers For CCS

MARCH 2025

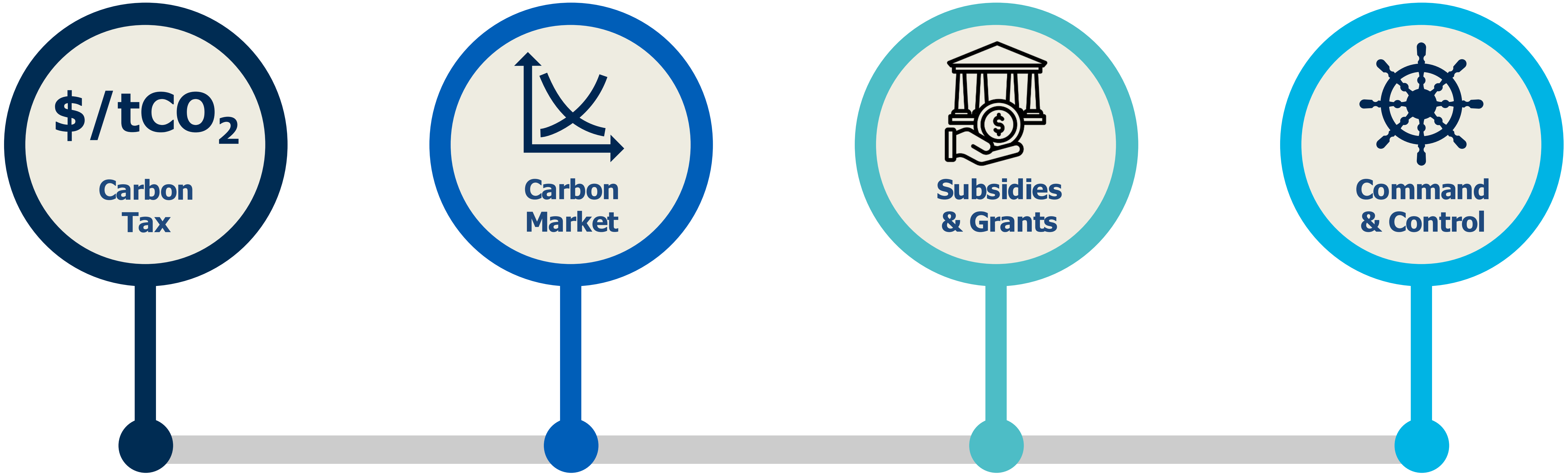
INTERNATIONAL DRIVERS FOR CCS

GLOBAL CCS INSTITUTE

DRIVERS

CCS is a vital and cost-effective abatement technology.

But to adequately define its economic value compared with freely emitting CO_2 requires intervention through policy and regulation.



EFFECTIVENESS OF DRIVERS

Carbon Markets

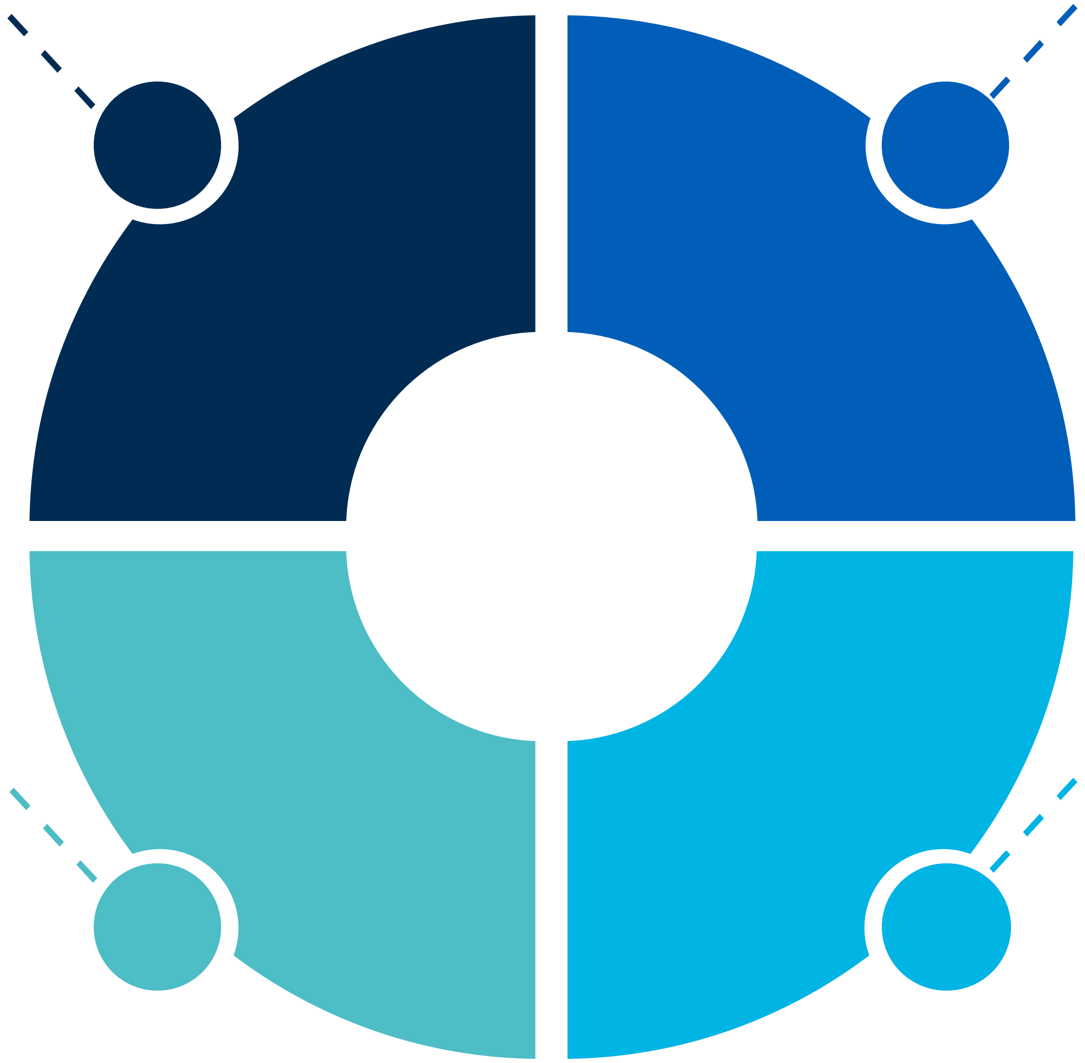
+ More efficient allocation of demand
+ Incentivises innovation
- Free allowances dilute price
- Exemptions are common

Subsidies & Grants

Tends to improve the chance of successful FID +

Can reduce costs of borrowing for projects +

Shifts risk to public sector ~



Carbon Tax

+ More certain carbon price
+ Incentivises innovation and efficient demand allocation
- Less responsive to underlying market

Command

Tend to have higher compliance & emissions mitigation +

Compliance costs -

Potential inefficiencies compared with market mechanisms -

TOOLS DEPLOYED - USA

IRA(*) – 45Q, 45V, and 45Z – Tax credits

Title 17 Clean Energy Financing(*) – Loan Guarantees

Office of Clean Energy Demonstrations(*) – Grants

State-based **Low Carbon Fuel Standards** – Carbon Markets

(*) – Potentially changing or already changed

TOOLS DEPLOYED - CANADA

CCUS Investment Tax Credit – Tax credits

Alberta Carbon Capture Incentive Program – Grants

Federal and State Carbon Pricing(*) (eg TIER) – Carbon Markets

(*) – Potentially changing

TOOLS DEPLOYED - EUROPE

EU ETS – Carbon Market

EU Innovation Fund – Direct financial support

Direct Investment – Northern Lights, Porthos

Carbon Border Adjustment Mechanism(*) – Carbon Duty on imports in certain cases (transition period until 2026)

(*) – Potentially changing

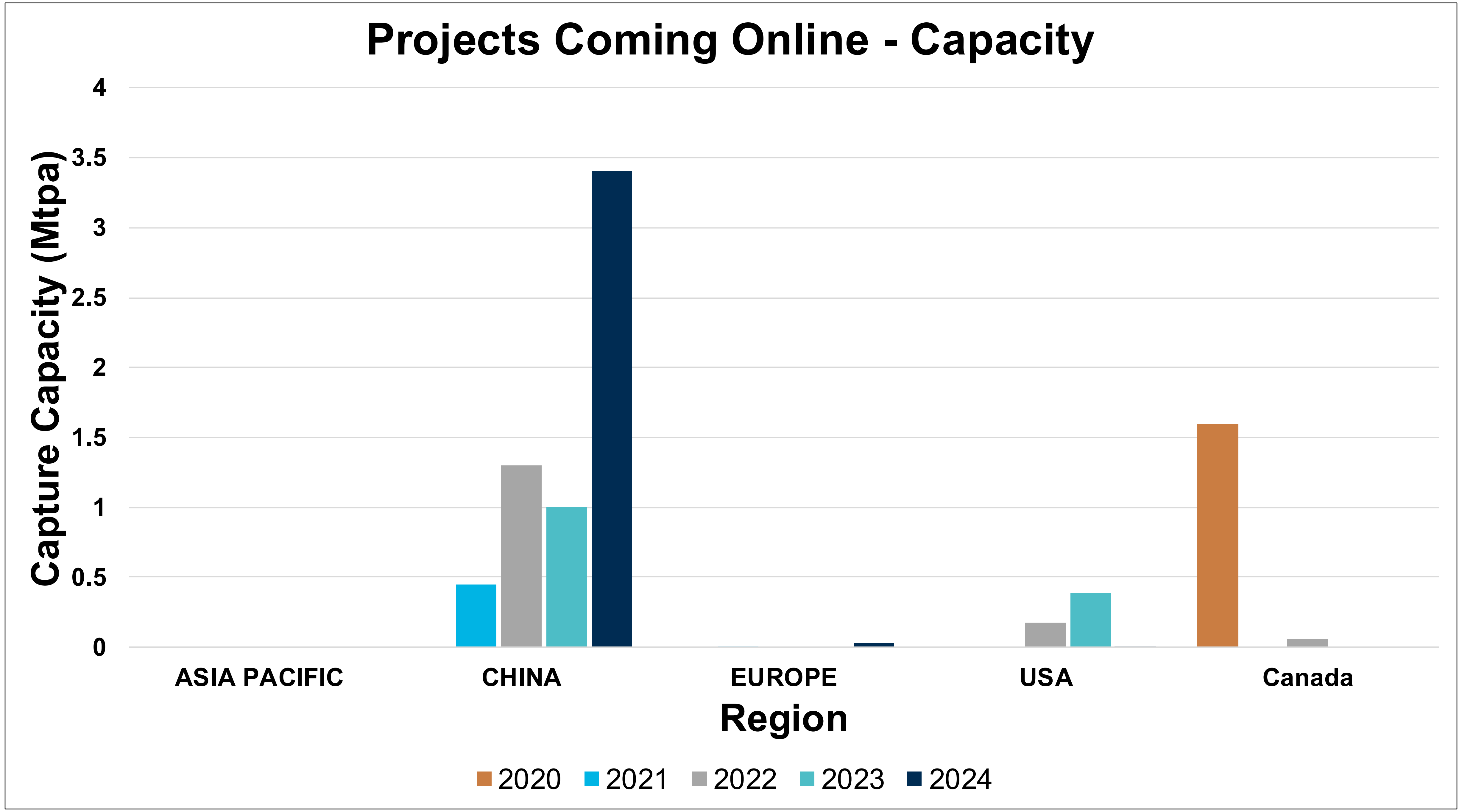
TOOLS DEPLOYED – ASIA PACIFIC

Carbon Markets or Tax – Japan, Australia, South Korea, Singapore, China, New Zealand

State Owned Enterprises – Japan, Malaysia, Singapore, China

Grants – Japan, South Korea

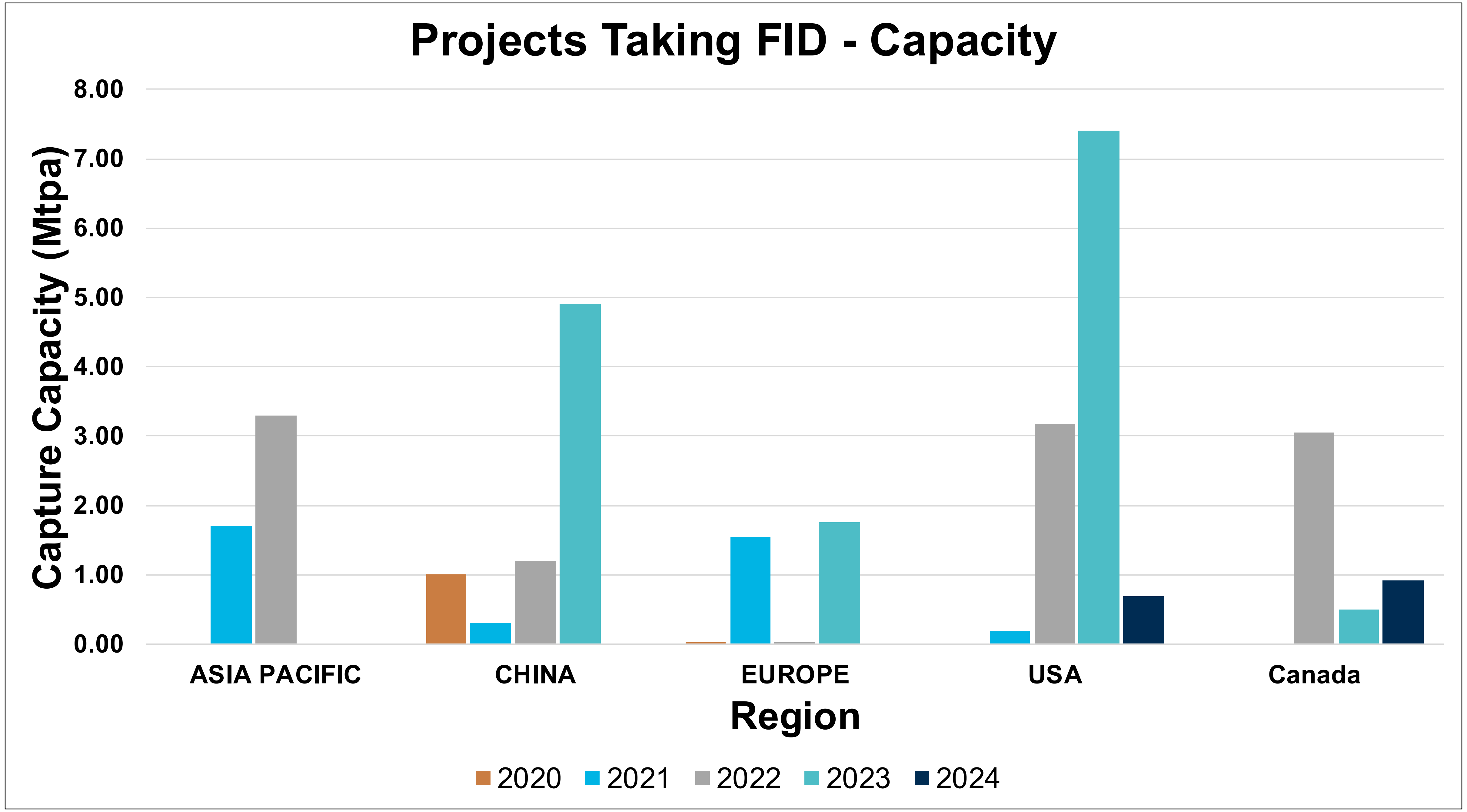
HAS THIS WORKED? – OPERATIONAL



July 2024 Data

Missing:
Moomba CCS
(1.7 Mtpa)

HAS THIS WORKED? – FID



July 2024 Data

Missing:
Net Zero Teesside (2 Mtpa)

Celsio (0.4 Mtpa)

Greensand (0.35 Mtpa)

& others – Feb Data imminent

QUESTIONS – DRIVERS FOR CCS

What **has been working well** in your region?

What **has not been working well** in your region?

How do countries best **create long-term certainty**?

What **role should the private sector play** in driving CCS deployment?

THANK YOU

GLOBAL CCS
INSTITUTE

Breakout 2: Moving Towards 100% Capture

7.1: Net Zero Teesside

Topical background slides for high capture session
j.gibbins@sheffield.ac.uk

https://www.bbc.com/news/articles/c9deq8enxljo

Home News Sport Business Innovation Culture Arts Travel Earth Audio Video Live

Jason Arunn Murugesu
BBC News, North East and Cumbria

The power station is planned for the Teesworks site, near Redcar

The Court of Appeal has heard there is a "tension" in the government's decision to approve a new "net zero" gas power station.

'Inconsistency'

Barrister Catherine Dobson, representing Dr Boswell, had **previously told** the High Court the environmental consultant had exposed "a large double-counting error" regarding how the power station's greenhouse gas emissions would be calculated.

She said the final assessment - that it may contribute more than 20 million tonnes of "carbon dioxide equivalent" into the atmosphere over its lifetime - was "significantly greater" than previously estimated.

Ms Dobson told the Court of Appeal that the government had accepted Dr Boswell's calculations and had acknowledged the project's lifetime emissions could cause "significant adverse" effects.

Nevertheless, the government had granted permission for the scheme, insisting it would help the UK reach its goal of hitting **net zero by 2050**.

She said there was an "inconsistency" in this argument and the government had not given a "coherent explanation".

She said the government had an "obligation" to reach a "reasoned conclusion" on the project's environmental impact and had so far failed to do so.

'Question of judgement'

Barrister Rose Grogan, representing DESNZ, described the case brought by Dr Boswell as the "epitome of a legalistic obstacle course-type" challenge.

She said the government accepted that the plant would produce greenhouse gas emissions that caused a "significant adverse" impact, but that this alone did not prevent it from approving such schemes.

"This is a question of judgement," she said.

"Fossil fuel remains part of the government's energy mix," she said. "It's part of the transition to a low-carbon economy... but it needs to be low carbon through the deployment of CCS [carbon capture and storage]."

The case continues.

https://www.bbc.com/news/articles/ce8vz9v6492o

On the case's second day, Ms Grogan continued to argue that the former secretary of state for energy security and net zero had acknowledged the "significant" carbon emissions the project would cause in her decision making process.

She said the minister was "entitled" to look at all types of factors when making the verdict.

In aiming to achieve net zero by 2050, Ms Grogan said the government had to balance "energy security" needs with possessing an "energy mix" which enabled back-up fuels if renewables were "not operational".

- Obvious question – this plant is funded by a Dispatchable Power Agreement – how will it dispatch?
- One suggestion is 200 warm starts and 50 cold starts per year, < 3000 hrs/yr with future renewables
- Helps a lot with upstream emissions, but plant needs to be able to handle capture during SUSD
- Dispatch/load factor not mentioned at all by the BBC correspondent in the court!
- Plant is quoted at up to 2 $MtCO_2$/yr elsewhere so numbers appear to be close to 100% load factor

February 2025

The Seventh Carbon Budget

Charts and data

https://www.theccc.org.uk/publication/the-seventh-carbon-budget/

Annual capacity factors implied by data for Figure 7.5.3

Annual capacity factors	2023	2030	2035	2040	2045	2050
Nuclear	79%	85%	83%	83%	83%	82%
CCS Biomass			68%	84%	88%	88%
Offshore wind	38%	45%	42%	45%	46%	47%
Onshore wind	24%	29%	29%	32%	33%	33%
Solar PV	10%	10%	10%	10%	10%	10%
Low-carbon dispatchable		46%	28%	27%	18%	14%
Unabated gas	28%	9%	5%	5%	2%	
Other generation	45%	44%	44%	44%	46%	47%

Table 2 Summary of cumulative GHG emissions from the Onshore and Offshore elements of the Proposed NZT – NEP Developments

DEVELOPMENT	PHASE	GHG EMISSIONS (TCO_2E)
Onshore Construction and Operation	Construction (4 years)	76,012
	Operation (25 years)	16,782,184
	Total Onshore	**16,858,196**
Offshore Construction and Operation	Construction (3 years)	324,699
	Operation (25 years)	30,988
	Decommissioning	1,721
	Total Offshore	**357,408**
Carbon capture *(NZT only)*	Carbon captured	-53,364,418
	T&S unavailability	3,592,523
	Overall carbon storage	**-49,771,895**
Whole life GHG emissions		**-32,556,291**

3.1.10 The net lifetime emissions impact of the Proposed Development and the proposed NEP development is therefore a net emissions reduction of over 32 $MtCO_2e$, relative to a without-project baseline, which is reasonably assumed to be an unabated Combined Cycle Gas Turbine of similar size and running hours.

https://infrastructure.planninginspectorate.gov.uk/wp-content/ipc/uploads/projects/EN010103/EN010103-002834-NZT%20DCO%209.53%20-%20Applicants%20Response%20to%20CEPP%20Letter%20Dated%2030%20May%202023%20-%20SoS%20RFI%204%20Aug%202023%20v3.pdf

Table 1 GHG emissions from the construction and operational phases of the Proposed Development

ONSHORE GHG EMISSIONS	ACTIVITY	GHG EMISSIONS (TCO_2E)
Construction	Embodied carbon of materials and products	64,170
	Material and product transport	2,974
	Electricity use	176
	Onsite fuel use	3,755
	Waste disposal	65
	Worker commuting	4,873
	Total construction emissions over construction duration	**76,012**
	Annualised	***19,003***
Operation	Electricity usage	11,779
	Uncaptured direct emissions from combustion of natural gas	5,929,380
	Well to Tank emissions from upstream supply of natural gas	10,101,668
	Waste disposal	308,892
	Workers commuting	7,922
	Materials	392,506
	Materials transport	30,037
	Total operation over 25 year period	**16,782,184**
	Annualised	***671,287***
Total Onshore GHG Emissions		***16,858,196***

https://infrastructure.planninginspectorate.gov.uk/wp-content/ipc/uploads/projects/EN010103/EN010103-002834-NZT%20DCO%209.53%20-%20Applicants%20Response%20to%20CEPP%20Letter%20Dated%2030%20May%202023%20-%20SoS%20RFI%204%20Aug%202023%20v3.pdf

CO_2 capture on the power plant

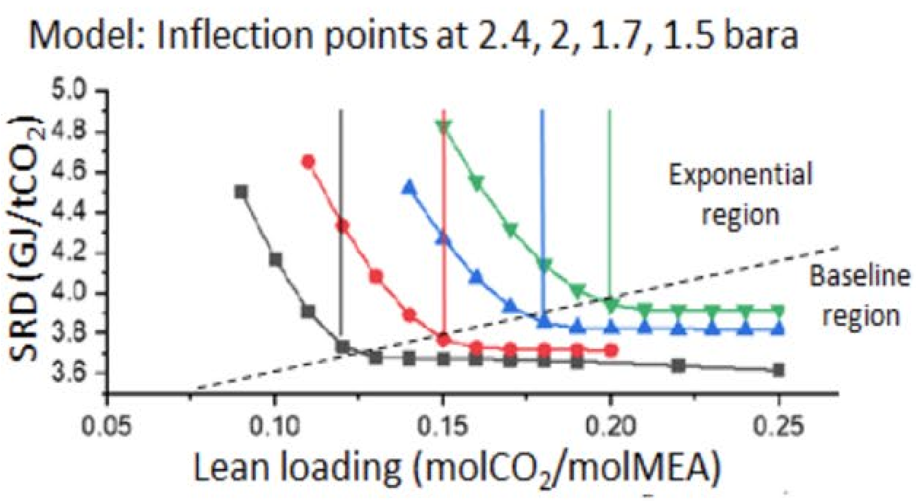
Uncaptured total	5,929,380
T&S unavailability	3,952,523
Captured	53,364,418
Total CO_2	59,293,798

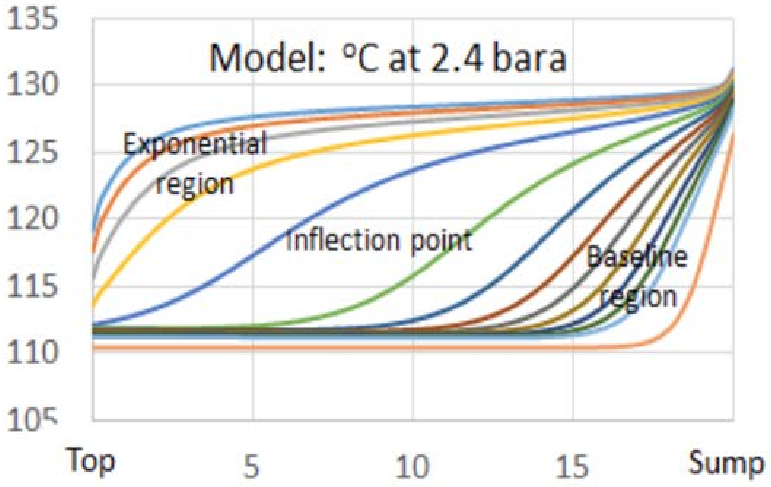
10% not captured

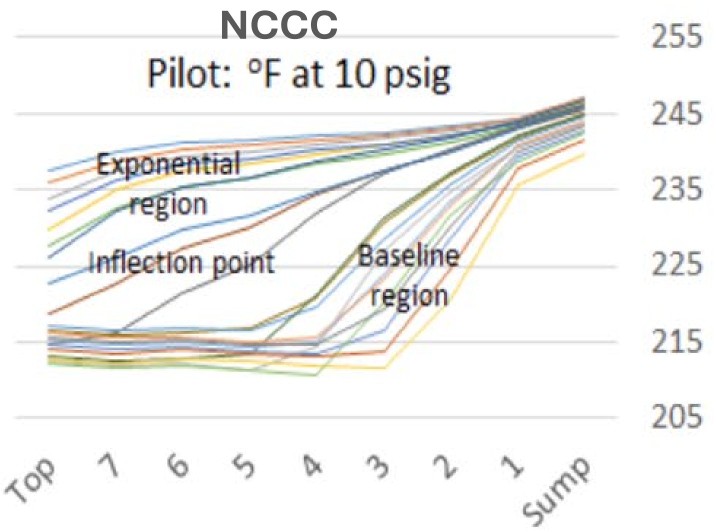
6.67% 'T&S unavailability' (this may be SUSD-related since, under the Dispatchable Power Agreement, if T&S is actually unavailable but the power/capture is available then the project still gets paid while not operating)

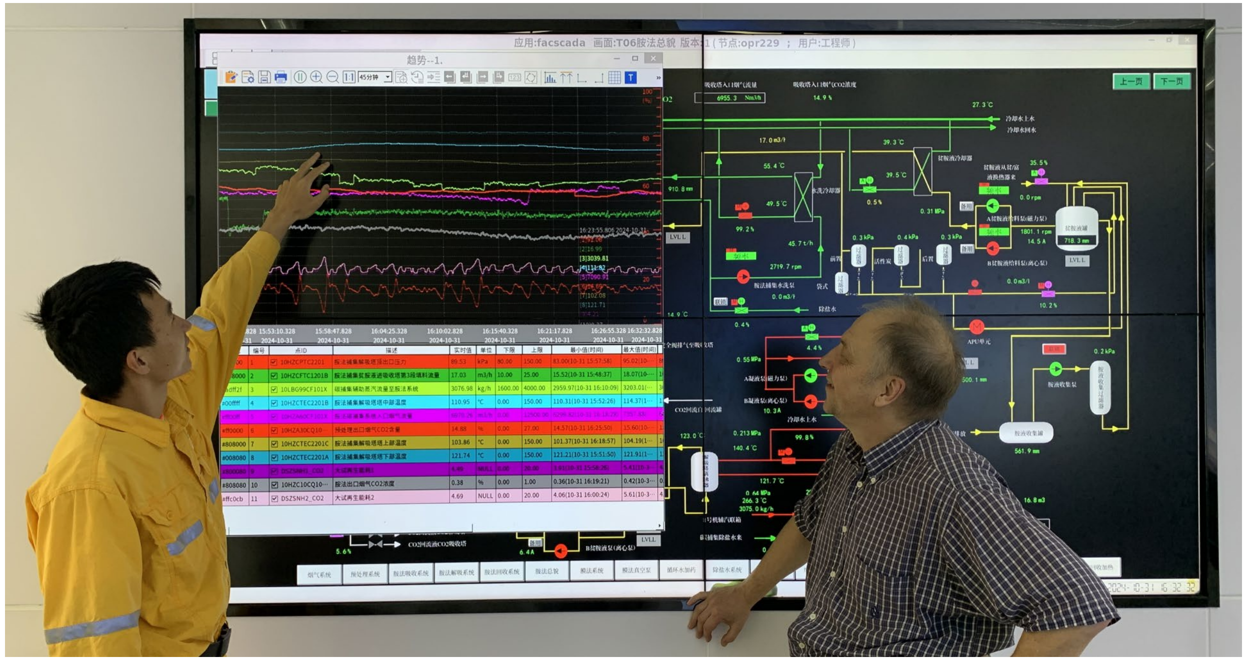
3.33% residual emissions. i.e. average capture rate of 96.7% of added CO_2

Getting the lowest possible lean loading without any extra specific reboiler duty (SRBD



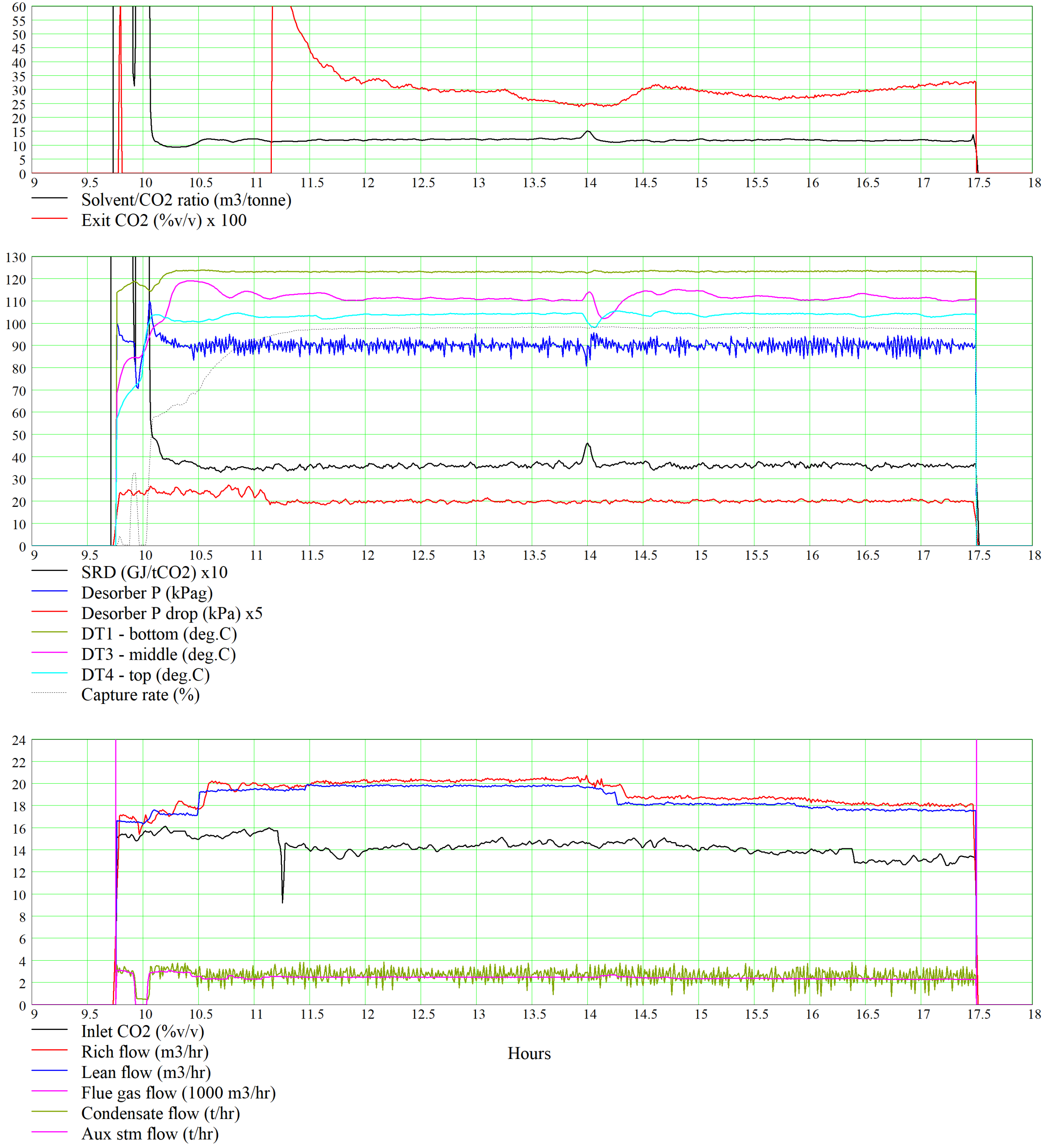






Haifeng 40 tpd pilot tests
Guangdong, China
October 2024

Haifeng 40 tpd pilot tests
Guangdong, China
1 November 2024



7.2: Moving Towards 100% Capture – Is It Possible and Is It Worth It?

Moving towards 100% capture – is it possible and is it worth it ?

Ryan Cownden, Mathieu Lucquiaud, Jon Gibbins
University of Sheffield, UK

8th IEAGHG CCS Cost Workshop, 6 Mar 2025

Contents

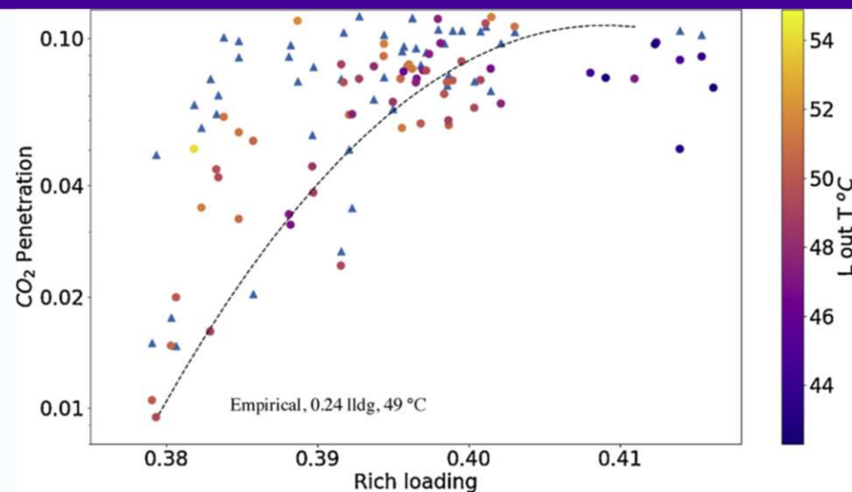
- Recent pilot-scale high capture demonstrations
  - Coal power and CCGT
  - Open-source solvents – MEA, PZ, CESAR-1
- Life cycle emissions for CCGT
- High capture cost studies
- Caveats and closing remarks
- All capture rates in this presentation are gross capture
  - % of total CO_2 in flue gas
  - Includes atmospheric CO_2
  - Coal power, ~99.8% ≈ 100% fossil-CO_2 capture
  - CCGT, ~99.2% gross capture ≈ 100% fossil-CO_2 capture

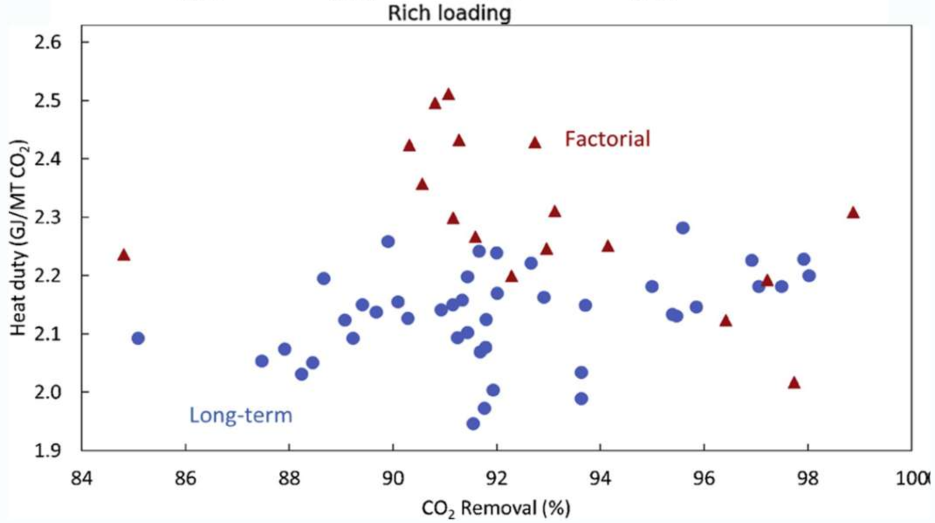
High capture with PZ

Coal-fired plant @ NCCC, 2018

- 4-6m PZ
- Absorber: 12m of M252Y
- Regen: 4m of RSR#0.5/0.7
- 68 steady-state points
- Up to 99% gross capture
- <5% increase in SRD from 90-99%

Gao et al (2019): doi.org/10.1016/j.ijggc.2019.02.013

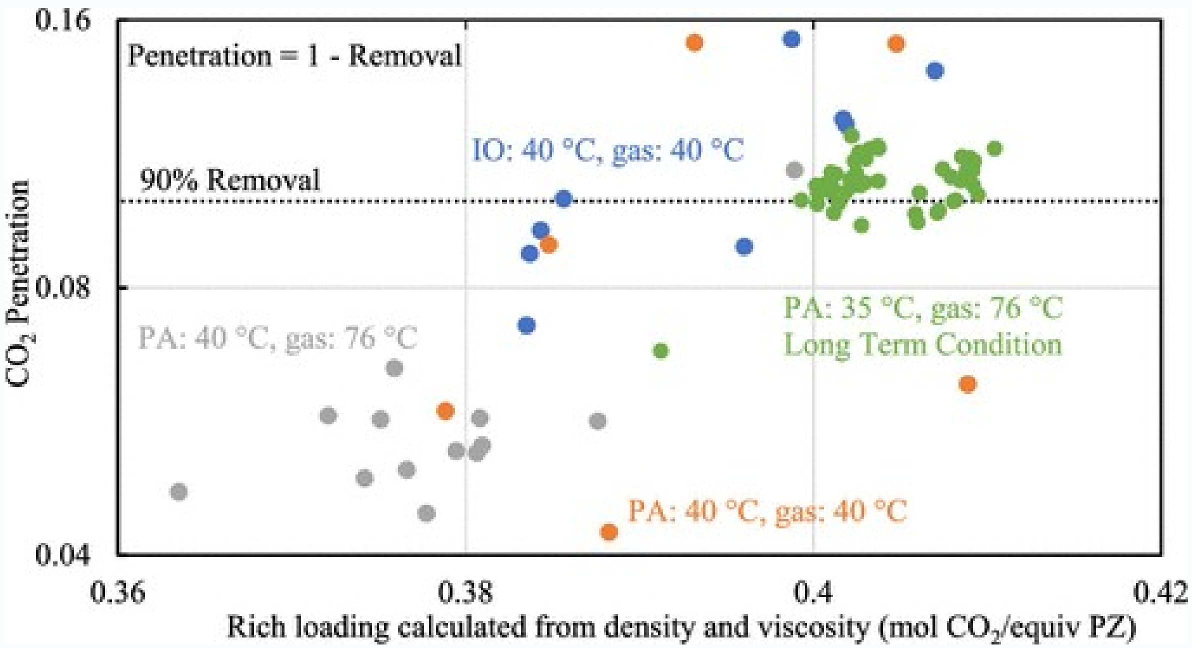




High capture with PZ

Simulated CCGT@ NCCC, 2019

- 4-6m PZ
- Exhaust CO_2 4.0-4.3% dry
- Absorber: 12m of M252Y
- Regen: 4m of RSR#0.5/0.7
- 80 steady-state points
- Up to 96% gross capture
- Lean/rich loading similar to coal



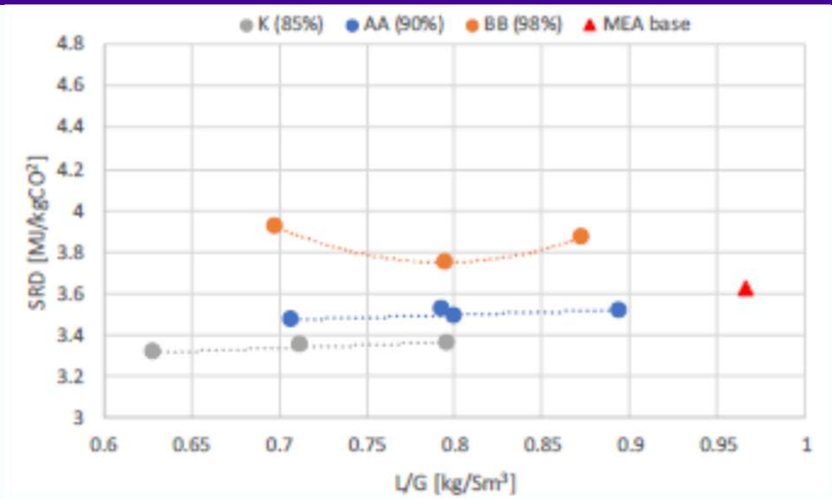
Gao et al (2020): DOI: 10.1021/acs.iecr.9b05733

High capture with CESAR-1

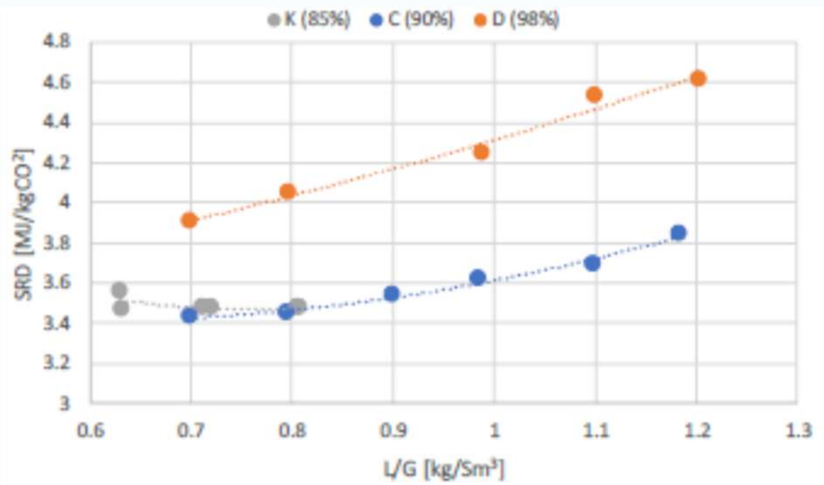
CCGT@ TCM, 2019

- 27%wt AMP, 13%wt PZ
- Exhaust CO_2 ~3.5% wet
- Absorber: 12-24m of 2X
- Regen: 8m of 2X
- 1500 h
- Up to 98% gross capture
- +7-10% in SRD from 90-99%

24m:



18m:

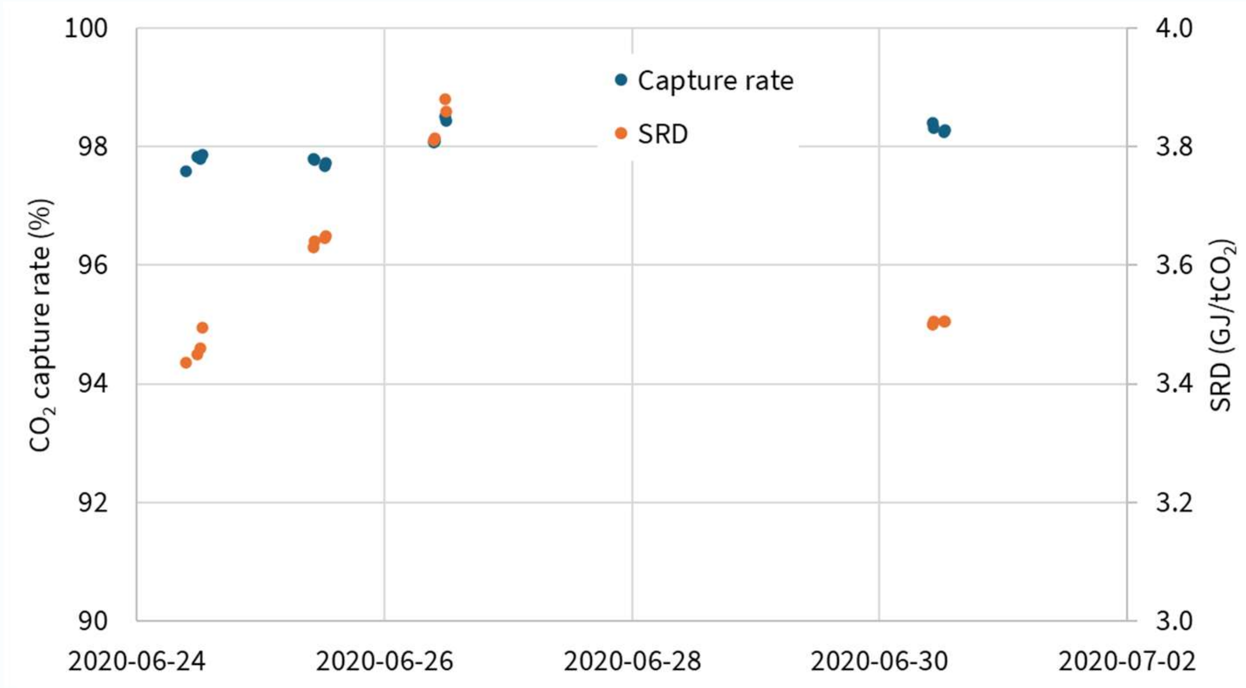


Benquet et al (2021): http://dx.doi.org/10.2139/ssrn.3814712

High capture with CESAR-1

CCGT@ TCM, 2020

- 27%wt AMP, 13%wt PZ
- Exhaust CO_2 ~5% dry
- Absorber: 24m of 2X
- Regen: 8m of 2X
- 7 d steady-state run
- 98% gross capture
- SRD: 3.4-3.9 GJ/tCO_2



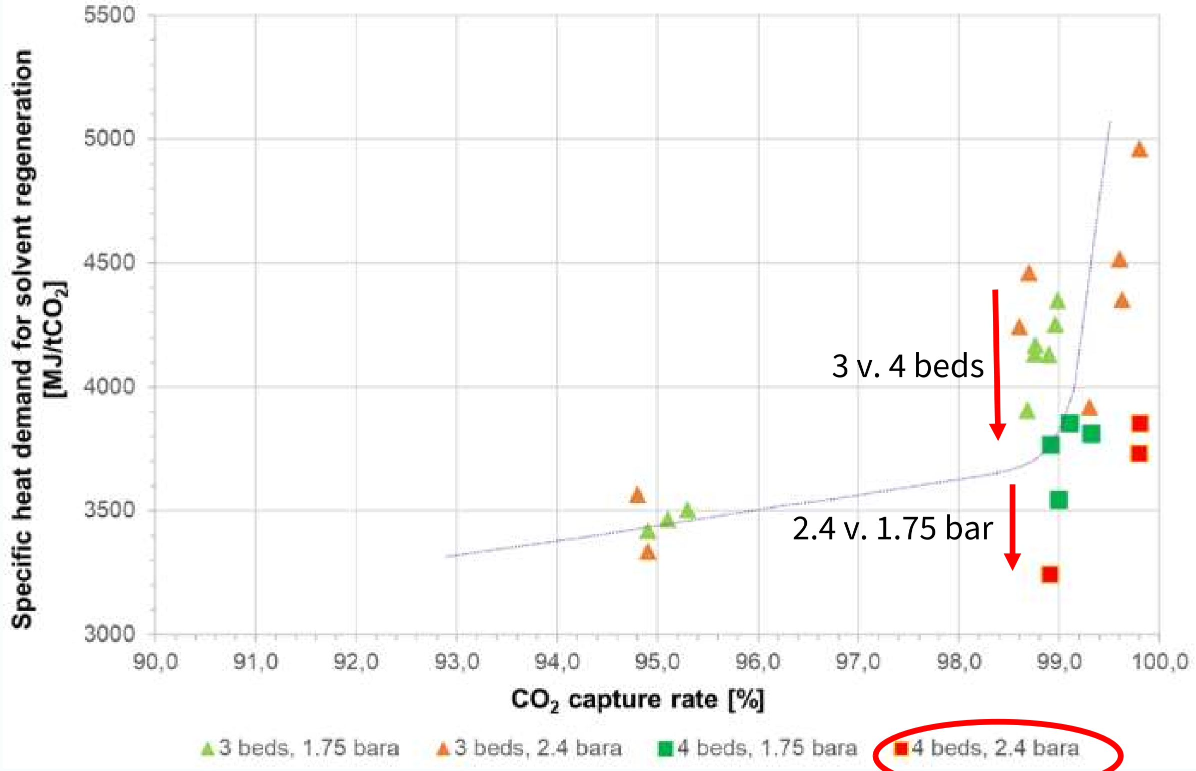
Hume et al (2021):
https://hdl.handle.net/11250/2786512

University of Sheffield

High capture with CESAR-1

Coal-fired @ Niederaussem, 2023/2024

- 27%wt AMP, 13%wt PZ
- Exhaust CO_2 ~14-16% dry
- 2 x 2-month tests
- Up to 99.8% gross capture
- SRD: 3.3-5.0 GJ/tCO_2

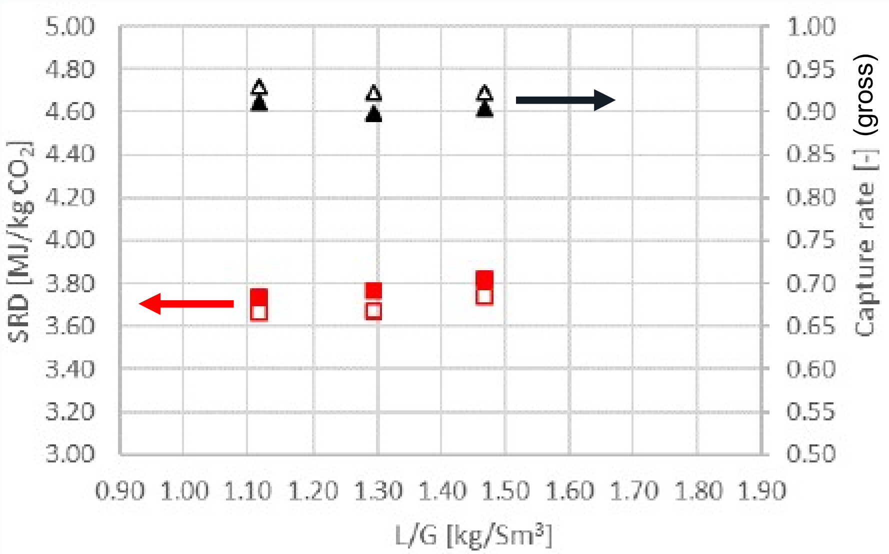


Moser et al (2024):
http://dx.doi.org/10.2139/ssrn.5016144

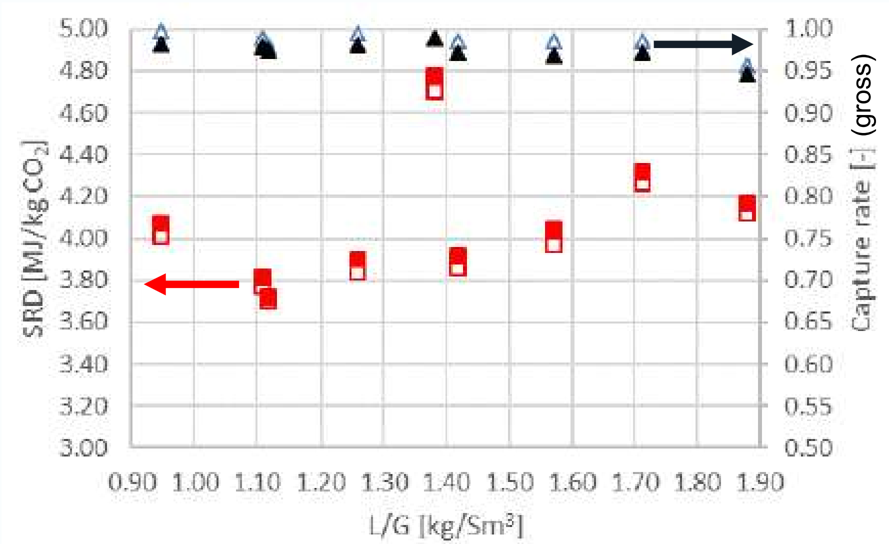
High capture with MEA

CCGT @ TCM, 2018

- 34-38%wt MEA
- Exhaust CO_2 ~4% wet
- Absorber: 24m of 2X
- Regen: 8m of 2X



59,000 Sm^3/h, ~92% gross capture



67,000 Sm^3/h, ~98% gross capture

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Shah et al (2021): dx.doi.org/10.2139/ssrn.3821061

High capture with MEA

Coal-fired @ Haifeng, 2024

- ~35%wt MEA
- Exhaust CO_2 ~14% dry
- Absorber: 15.9 m (MCC)
- Regen: 8.5 m (MCC)

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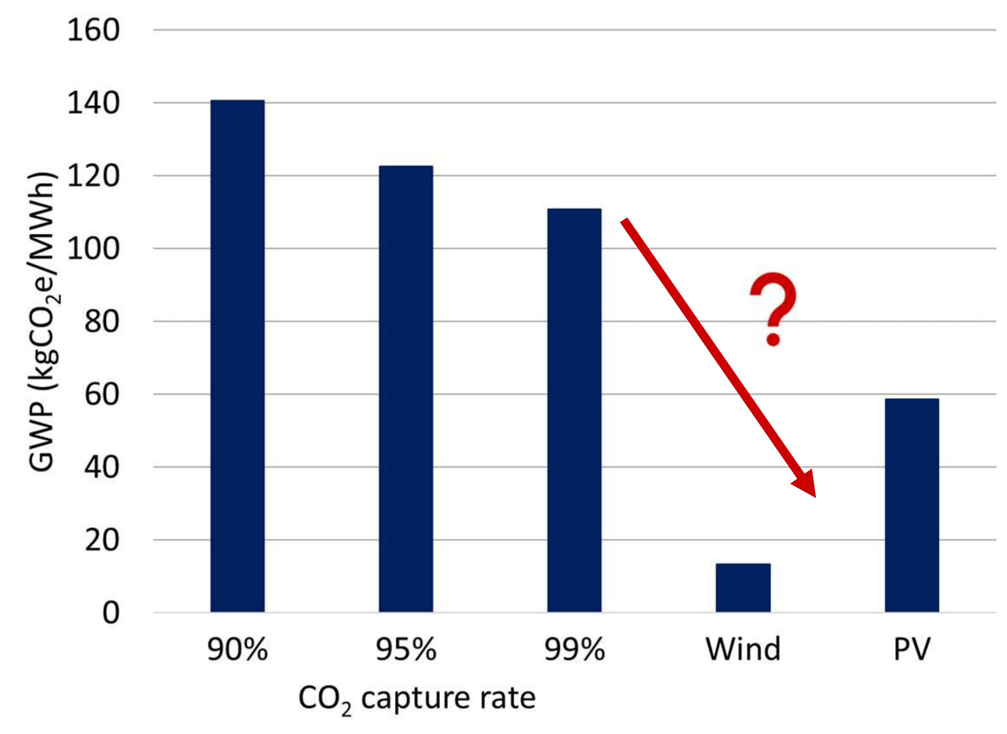
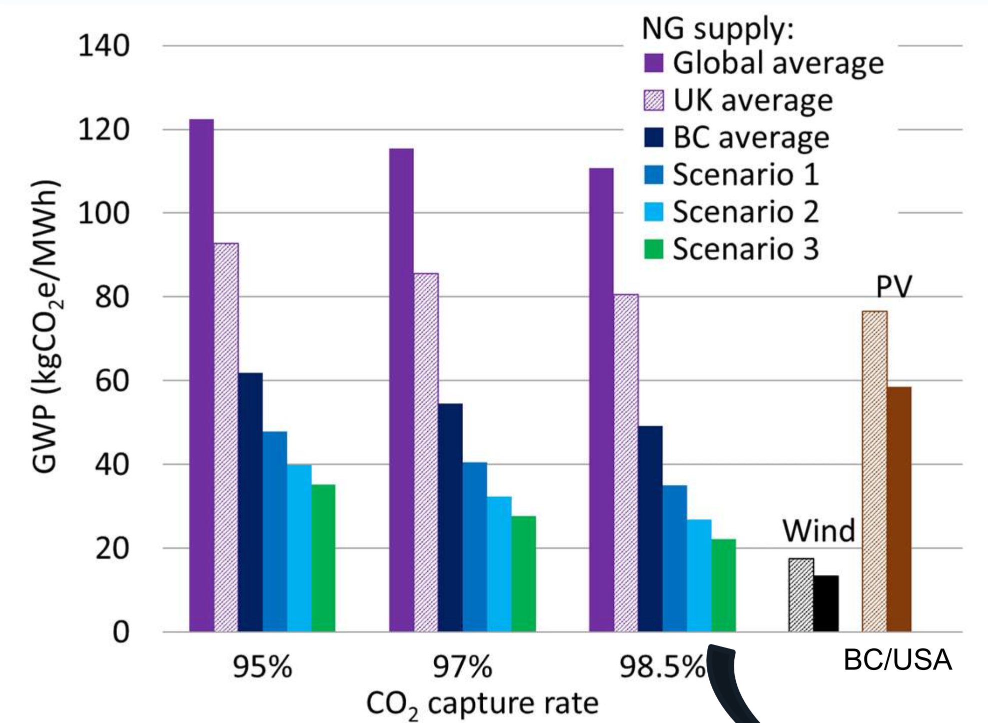
CCGT life cycle emissions

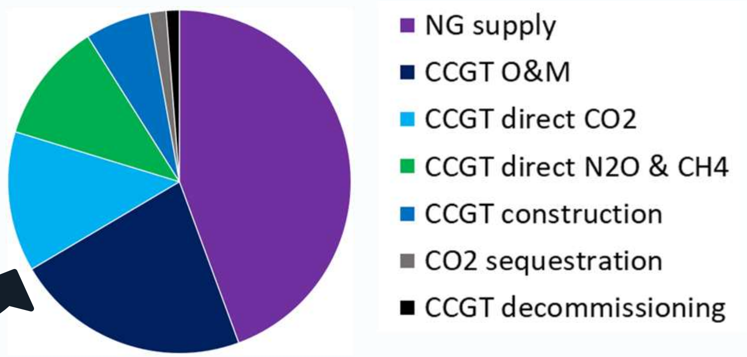
CCGT with CCS and global average NG supply



Baseload CCGT w/CCS GHG emissions



Low-emission NG supply
- BC: British Columbia, Canada
- #1: low-emission processing plant
- #2: electrify compressor drives
- #3: 2030 fugitive methane target
- UK domestic: ~BC
- Norway: ~#1-2



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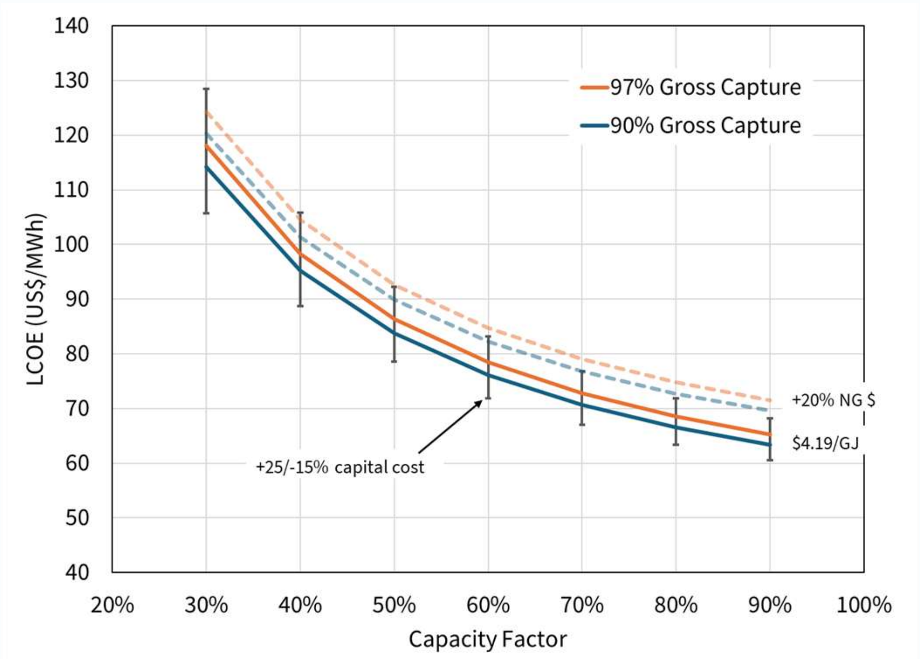
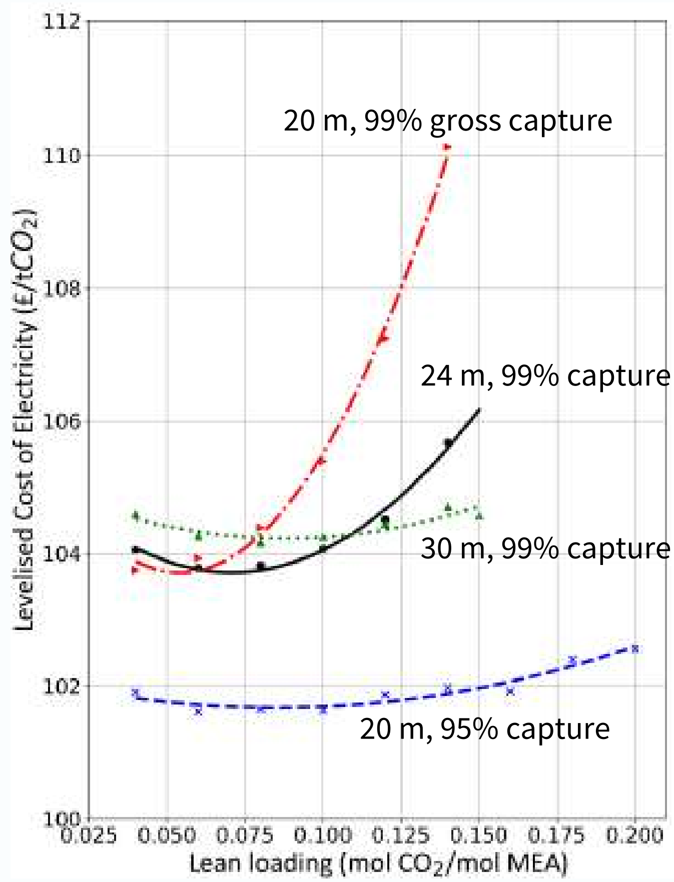
Cownden & Lucquiaud (2024): DOI: 10.1021/acs.est.4c02933

Impact of capture rate on cost

CCGT with CCS

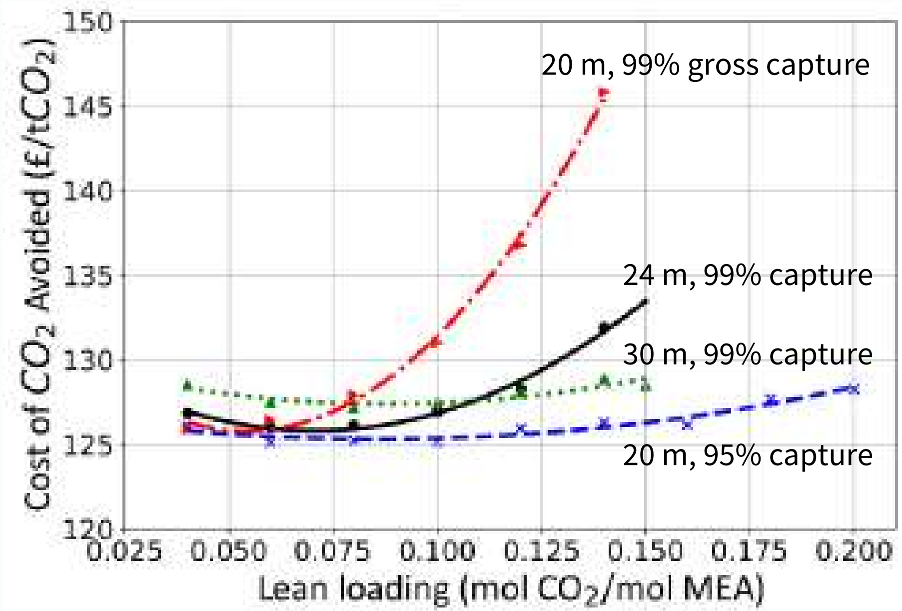




Based on data from NETL 2022 baseline study (DOE/NETL-2023/4320)

Mullen & Lucquiaud (2024): https://doi.org/10.1016/j.egyr.2024.04.067

Cost of avoided CO_2



Mullen & Lucquiaud (2024):
https://doi.org/10.1016/j.egyr.2024.04.067

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Caveats

- Long term testing needed – 12+ months continuous
  - Solvent degradation with high reboiler temperature
  - Solvent reclaiming/management
  - Air emissions (with degraded solvent)

- Need demonstration/design of high capture over life cycle operations
  - Plant availability - reliability/redundancy
  - Sequestration availability
  - Startup/shutdown emissions
  - Transient response
  - Off-design operation

Is it worth it?

- From whose perspective?

- Compared to what alternative?
  - High-permanence CDR?
  - Not operating?

- What is the value?
  - Social cost of CO_2 emissions - NPV of predicted economic losses?
  - Risk management to achieve net-zero – uncertain future cost of CDR?
  - Avoided carbon taxation/fees?
  - Market opportunity - life cycle emissions comparable to renewable energy?
  - Business insurance against future social/political/regulatory changes?
  - Social licence to operate?

Questions?

racownden1@sheffield.ac.uk

7.3: 100% Capture of Fossil CO_2: Should We Do It?

100% capture of fossil CO_2: Should we do it?

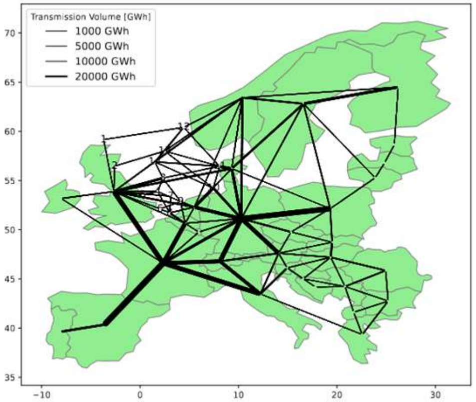
Simon Roussanaly[a], Shamim Homaie[b], Rahul Anantharaman[a], Asgeir Tomasgard[b], Truls Gundersen[b], Andrea Ramirez[c]

[a]SINTEF Energy Research, Norway
[b]NTNU, Norway
[c]TU Delft, The Netherlands

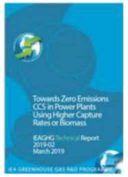
*Corresponding author: simon.roussanaly@sintef.no

SINTEF

In the power sector



EMPIRE tool
Developed by NTNU



Performance of net-zero fossil power from coal and gas based on IEAGHG 2019 study

CCS-high for different fuel types, the costs increase as follows [28]:

- Coal CCS-high: 6% increase compared to standard coal CCS.
- Lignite CCS-high: 6% increase compared to standard lignite CCS.
- Gas CCS-high: 7% increase compared to standard gas CCS.

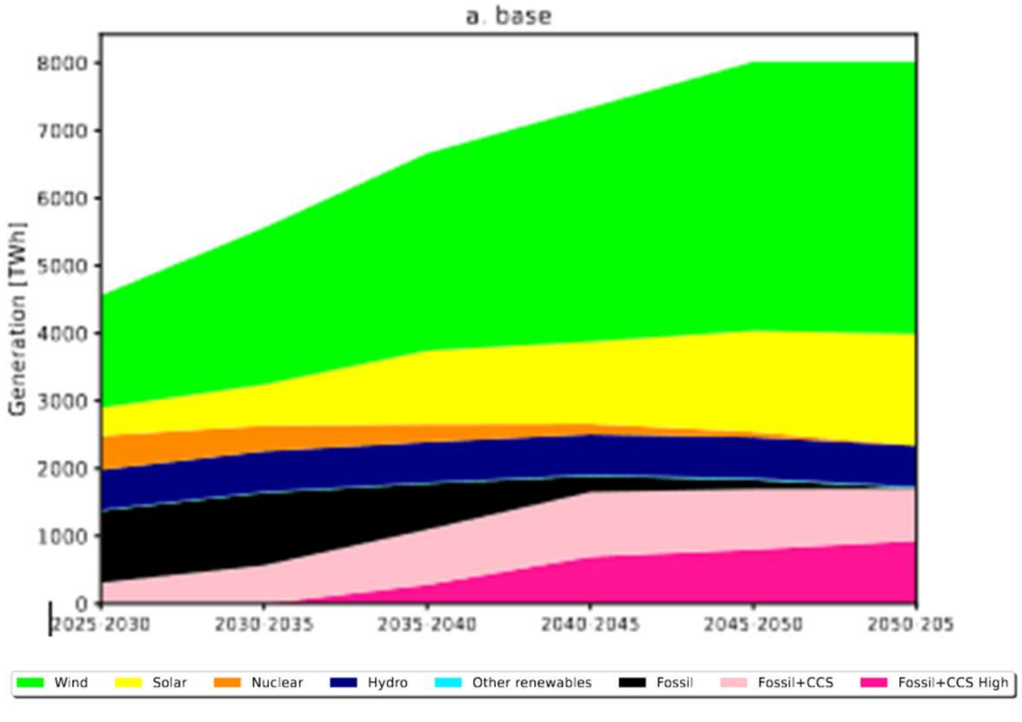
In terms of efficiency, switching from standard CCS to CCS-high results in a decrease. The efficiency reductions, based on fuel types, are as follows [28]:

- Coal CCS-high: 1.5% decrease in efficiency compared to standard coal CCS.
- Lignite CCS-high: 1.5% decrease in efficiency compared to standard lignite CCS.
- Gas CCS-high: 2.2% decrease in efficiency compared to standard gas CCS.

The role of carbon capture and storage in decarbonizing the European power sector

Shamim Homaei[1*], Rahul Anantharaman[2], Simon Roussanaly[2], Asgeir Tomasgard[1]

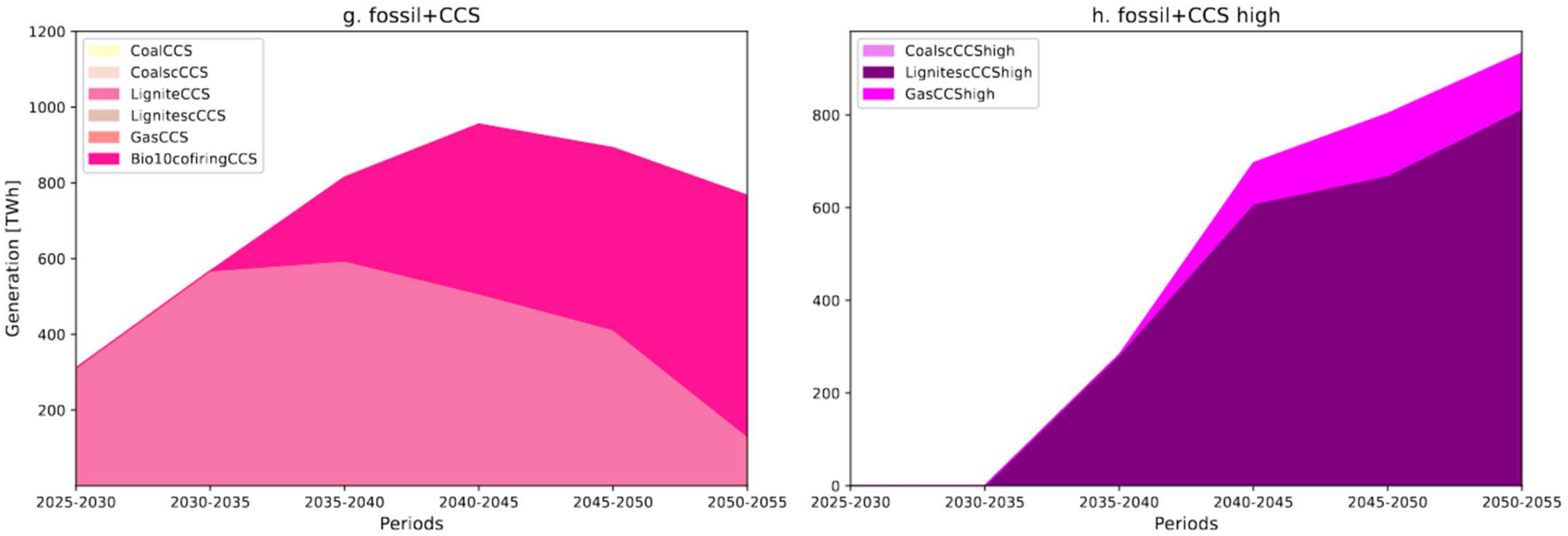
Power system based on 99% reduction in emission in 2050 compared to 1990 levels



In the power sector

The role of carbon capture and storage in decarbonizing the European power sector

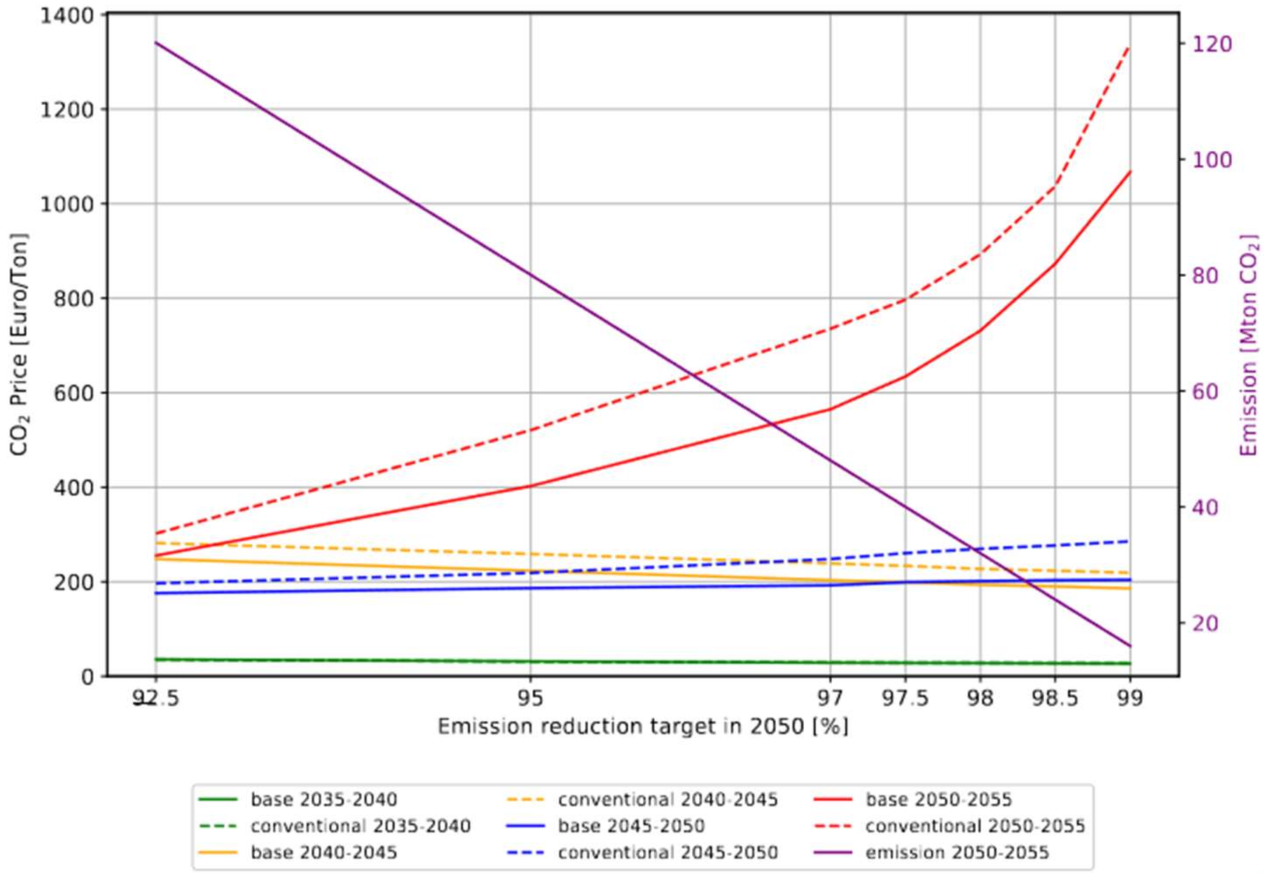
Shamim Homaei[1*], Rahul Anantharaman[2], Simon Roussanaly[2], Asgeir Tomasgard[1]



In the power sector

The role of carbon capture and storage in decarbonizing the European power sector

Shamim Homaei[1*], Rahul Anantharaman[2], Simon Roussanaly[2], Asgeir Tomasgard[1]



In the industry sector

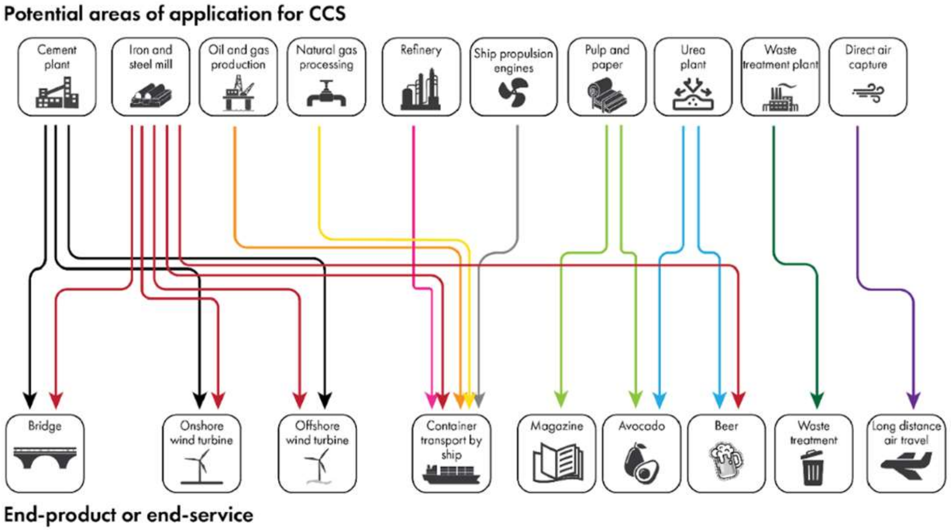


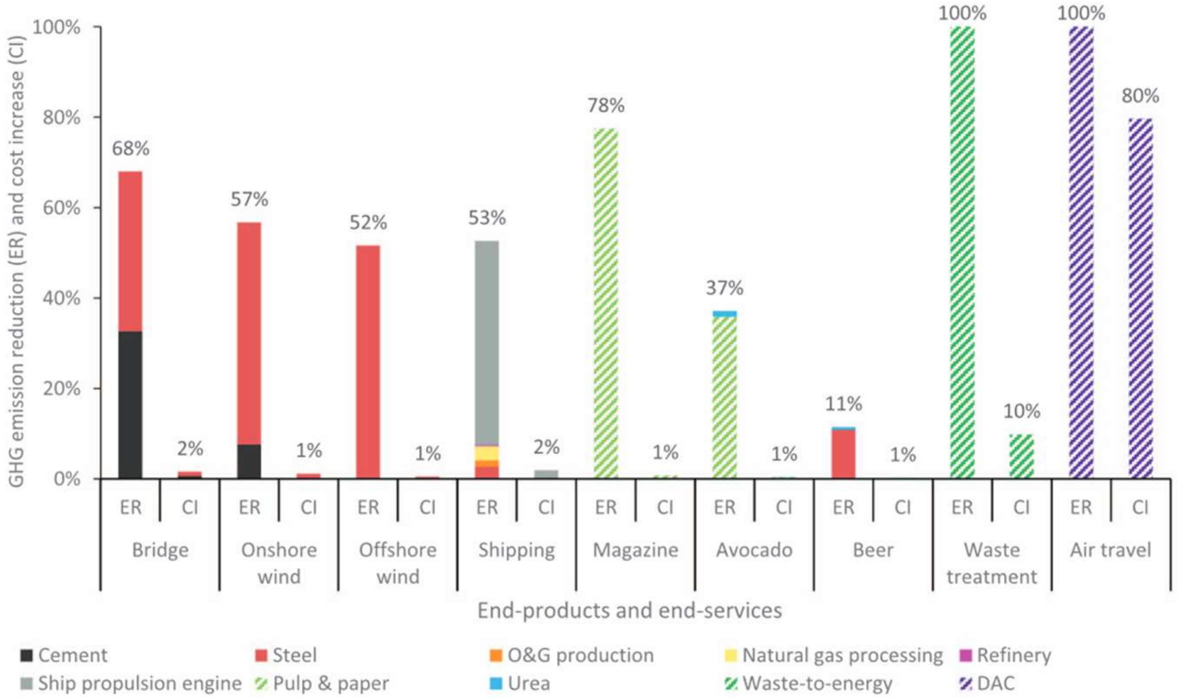
Figure 1. Interconnections between the considered end-products/services and the CCS applications considered in this study.

Progress in Energy

PERSPECTIVE

Putting the costs and benefits of carbon capture and storage into perspective: a multi-sector to multi-product analysis

Simon Roussanaly[1,*], Truls Gundersen[2] and Andrea Ramirez[3]



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- The ACCSESS project (www.projectaccsess.eu), which received funding from the European Union's Horizon 2020 research and innovation programme under grant agreement No 101022487.

Breakout 3: Impact of Plant Integration

8.1: Impact of Plant Integration

EPRI

GENERATION

Impact of Plant Integration

Breakout Session

Abhoyjit S. Bhown, Ph.D.
Sr. Program Manager

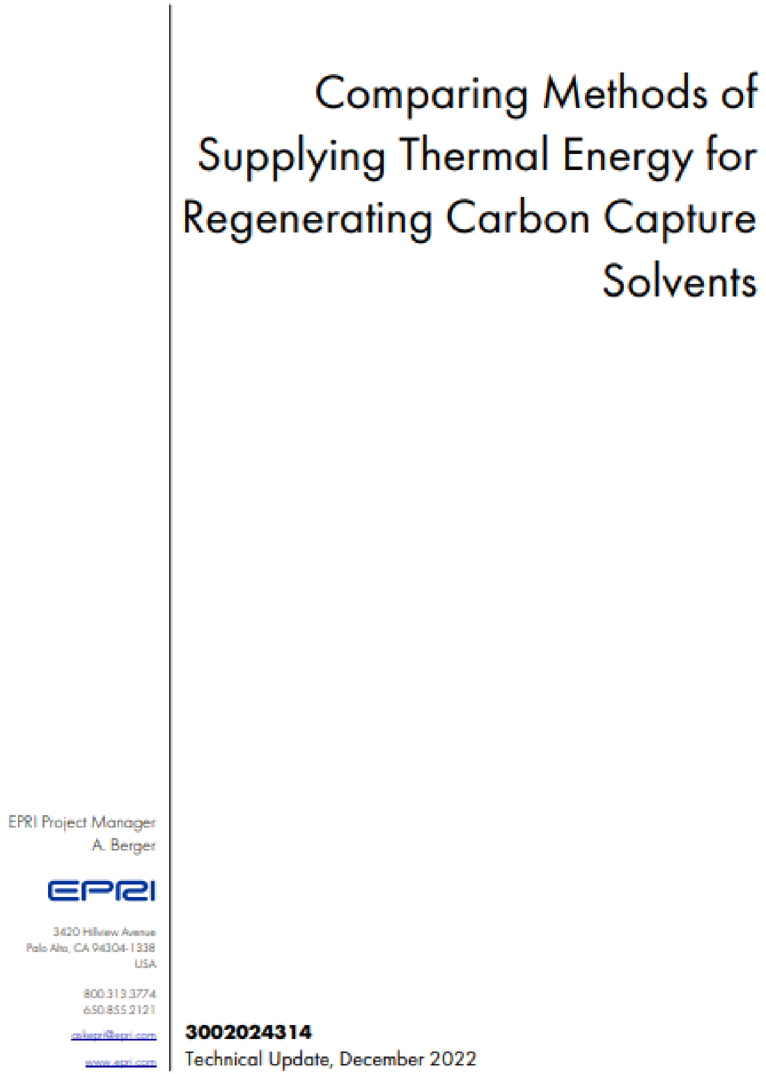
8th CCS Cost Network Workshop
March 5-6
Houston, TX

Two Studies

- Integration (3002024314, 2022)
- Environmental Considerations (3002030909, 2024)
  - Air Quality
  - Water
  - Land
  - Public Engagement

Power Plant Integration

- Introduction
- 3 Regeneration Options
  - Steam extraction, standalone CHP, boiler
- 4 Base Plants
  - DOE baselines, Peterhead, Petra Nova
- Key Performance Metrics
- Case Comparison and Findings
  - Steam extraction: most efficient, potential lower cost, least flexible
  - CHP: efficient, produces extra electricity, flexible, most expensive
  - Boiler: no derate on power plant, least efficient, most flexible



Comparing Methods of Supplying Thermal Energy for Regenerating Carbon Capture Solvents

EPRI Project Manager
A. Berger

3420 Hillview Avenue
Palo Alto, CA 94304-1338
USA

800.313.3774
650.855.2121

www.epri.com

3002024314
Technical Update, December 2022

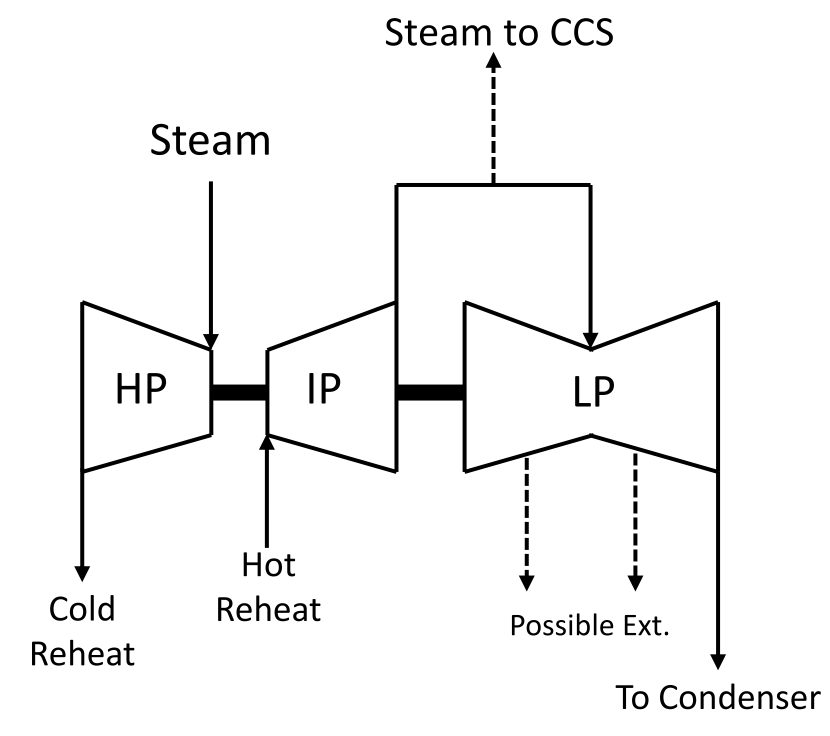
Introduction – Steam Requirement for CCS

- Large amount of steam is need in the reboiler
  - 2.5-3 GJ/t @ 120 – 150 °C
- Modeling work tends to use steam extraction
  - High thermal efficiency
  - Extracted from IP/LP crossover
  - 38-45% of LP steam, impacts turbine operation and performance
- Demonstration units tend to use standalone steam generation
  - Flexibility and simplicity
  - Minimal power plant modification and no plant derating
  - Space for retrofit plant
  - Plant integration
- Recent FEEDs do not have conclusive findings (de-rate, flexibility)

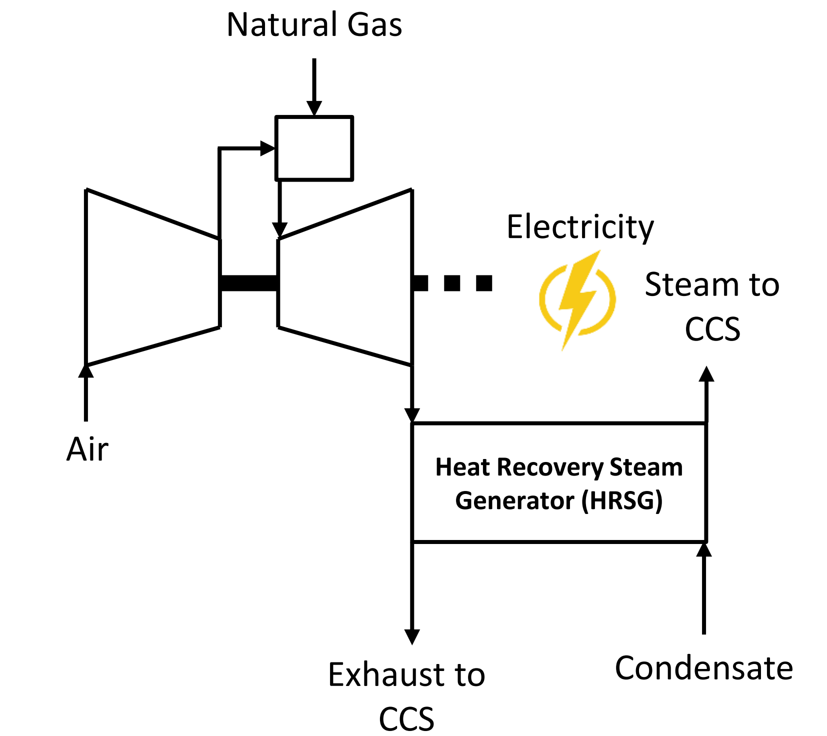
Regeneration Options – How to Provide Thermal Energy?

- Reboiler: 130-150 °C → Low Pressure (LP) Steam @ 2.8 to 5 bar
- Literature on each individual option exists, but no systematic study
  - Considered coal-fired and 2 gas-fired power plants with each regeneration option

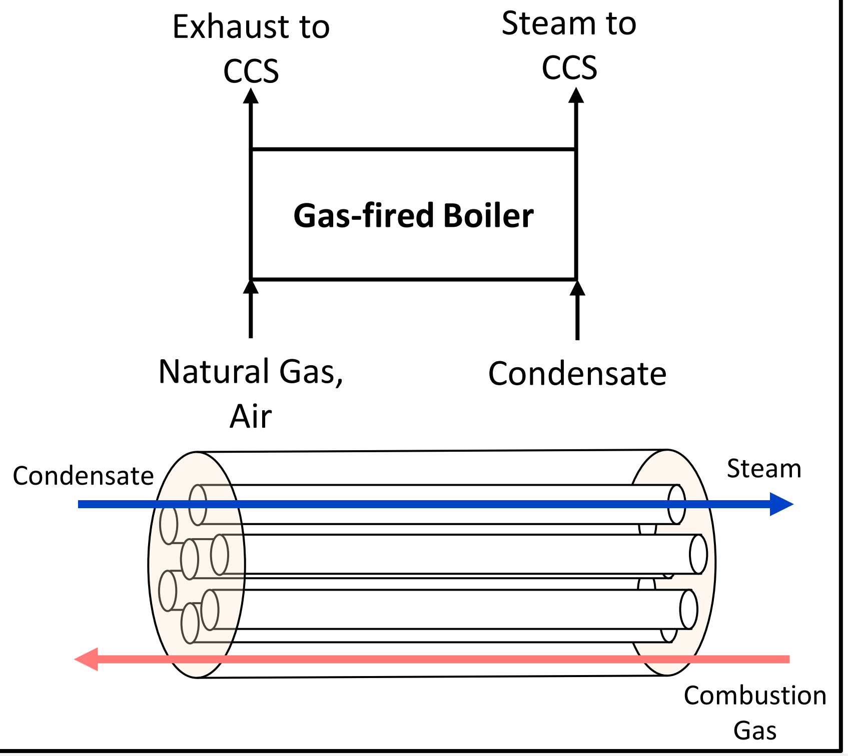
A: Steam Extraction from Power Plant



B: Standalone Combined Heat and Power (CHP)



C: Standalone Gas-fired Boiler



Case Analysis – Base Plant Selection

Cases	Plant			
Thermal Options	1: NETL, coal, 650 MW_{net}	2: NETL, NGCC, 740 MW_{net}	3: Peterhead, NGCC, (Scotland) 400 Mw_{net}	4: Petra Nova by NRG & JX EOR 240 MWe
CCS technology	Shell Cansolv®	Shell Cansolv®	Shell Cansolv®	MHI KM-CDR®
A: Steam Extraction	**1A**	**2A**	**3A**	
B: CHP	1B	2B	3B	**4B**
C: NG Boiler	1C	2C	3C	
Sources	NETL Cost and Performance Baseline for Fossil Energy Plants. Rev4		Peterhead CCS FEED by Shell U.K.	Petra Nova Technical Report

Focus of the report

90% capture from base plant and standalone unit

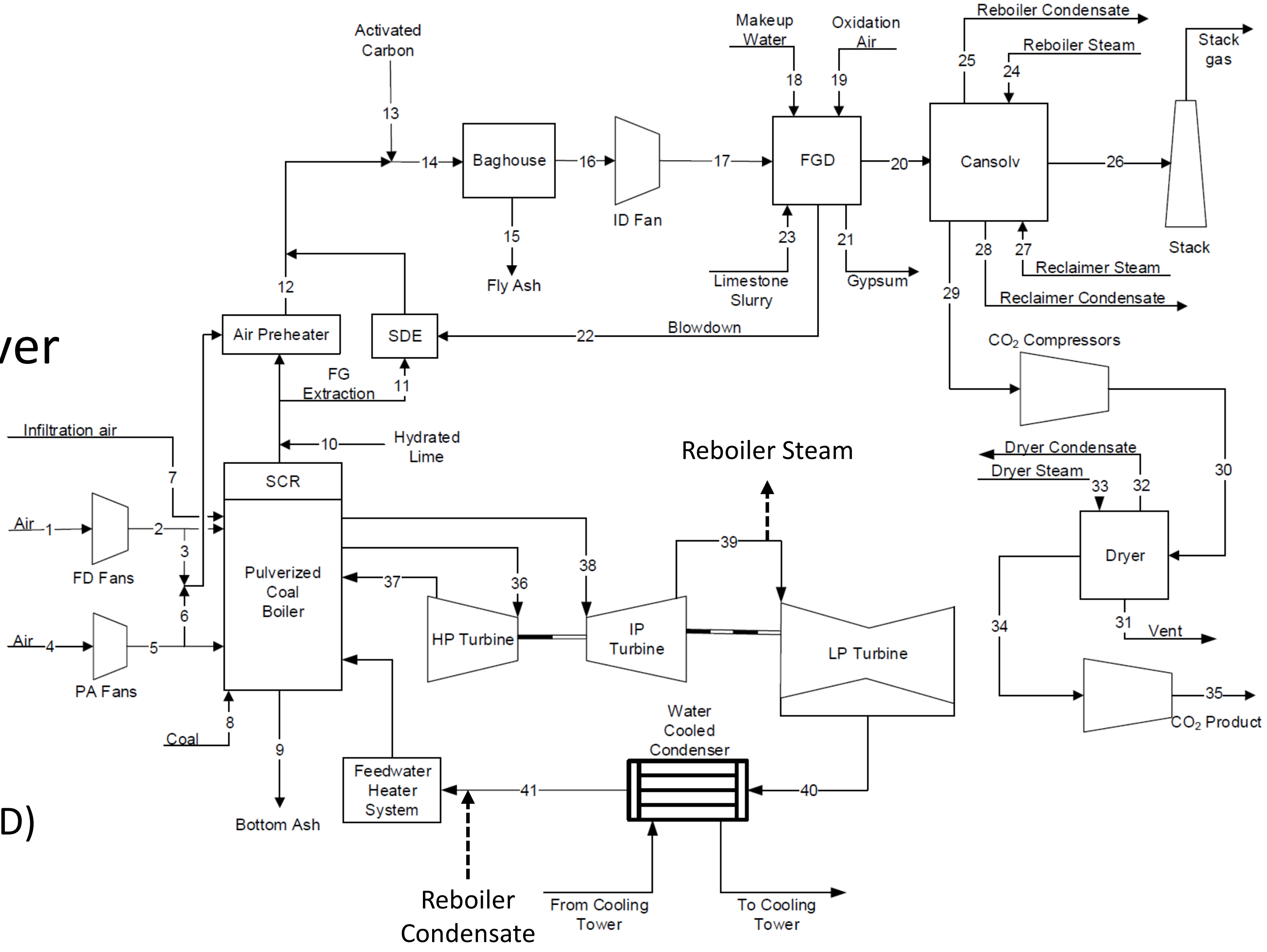
Case Analysis – Key Performance Metrics

- General considerations
  - Plant configuration
  - Conditions of steam extraction and condensate return
- Energy Production
  - Plant Efficiency
  - Parasitic Energy
  - Coefficient of Performance
    - Developed metric for understanding additional fuel for steam generation
- Water Withdrawal
- Capital Cost
- Flexibility

Parameter	Calculation
Plant Efficiency	$\frac{Net\ Power\ (MW_e)}{HHV_{fuel}\ (MW_t)}$
Parasitic Energy	Percent reduction in plant efficiency
Coefficient of Performance	MW_t steam produced for the reboiler per additional MW_t fuel input
Water Withdrawal	$\dot{m}_{Water} = \dot{m}_{Power\ Plant} + \dot{m}_{CCS}$

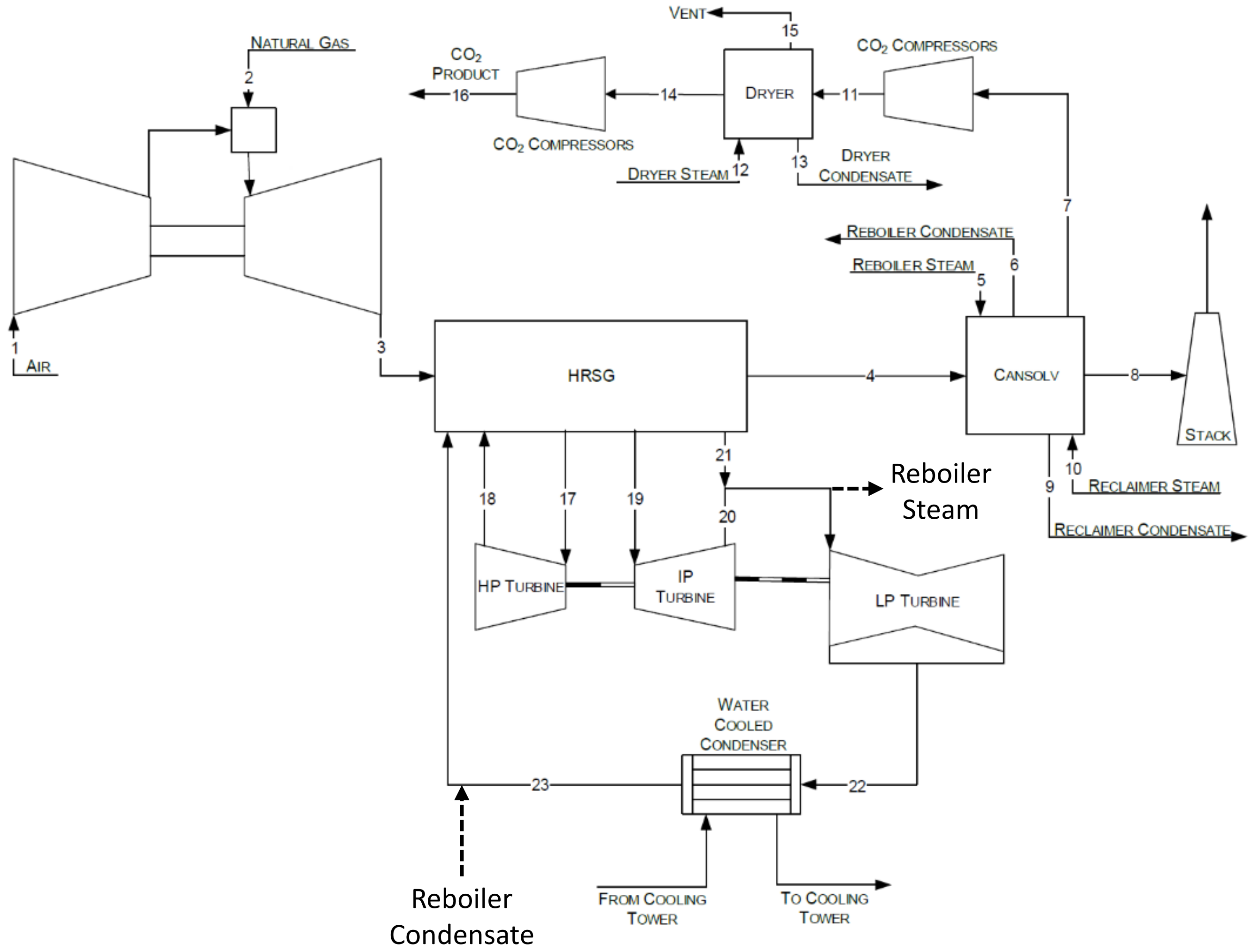
Plant 1A: Net 650 MWe Coal-fired + Steam Extraction

- Case 12B from NETL rev. 4
- Gross Power
  - Base: 685 MWe; CCS: 770 MWe
  - Increased fuel input due to aux. power requirements
- Steam extracted from IP/LP Crossover
  - 5 bar @ 270 °C (attemperated to 150 °C)
  - 600 t/hr (~38% of steam in crossover)
- Capture Process
  - Shell Cansolv®
  - Flue gas with 13 mol % CO_2
  - 90% CO_2 removal (581 tCO_2/hr)
  - Downstream of flue gas desulfurization (FGD) for SO_2 control



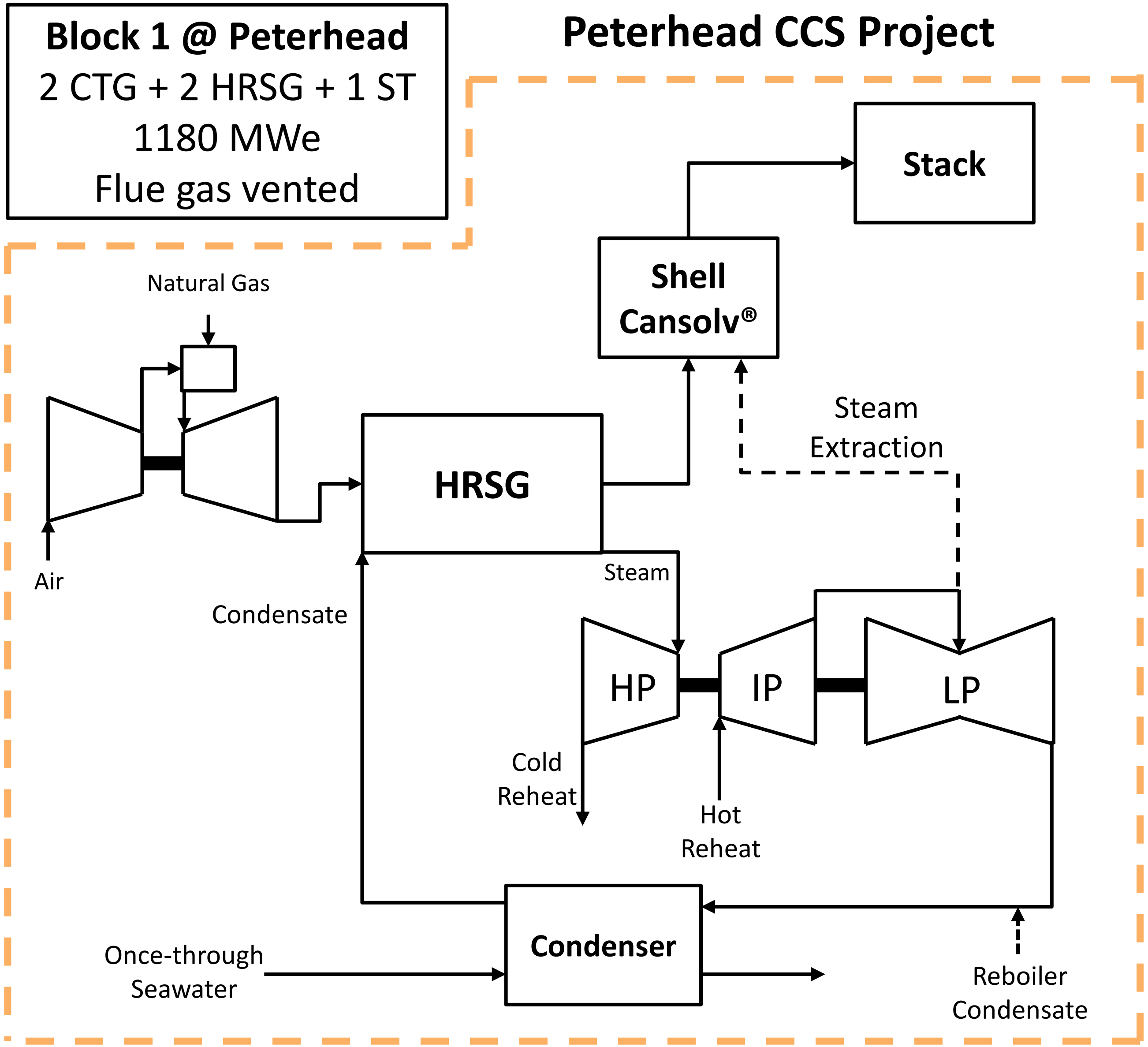
Plant 2A: NGCC + Steam Extraction

- Case 31B from NETL rev. 4
- Base case vs. w/ CCS @ same fuel input (1223 MWt)
  - Gross Power: 740 MWe vs. 690 MWe
  - Net Power: 727 MWe vs. 646 MWe
- Steam extracted from IP/LP Crossover
  - 5 bar @ 308 °C (attemperated to 150 °C)
  - 260 t/hr (~41% of steam in crossover)
- Capture Process
  - Shell Cansolv®
  - Flue gas with 4% CO_2
  - 90% CO_2 removal (223 tCO_2/hr)
  - No FGD required (low SO_2 content)
  - Direct contact cooler (DCC) to cool flue gas (leaves HRSG @ 110 °C)



Case 3A: NGCC + Steam Extraction – Peterhead CCS

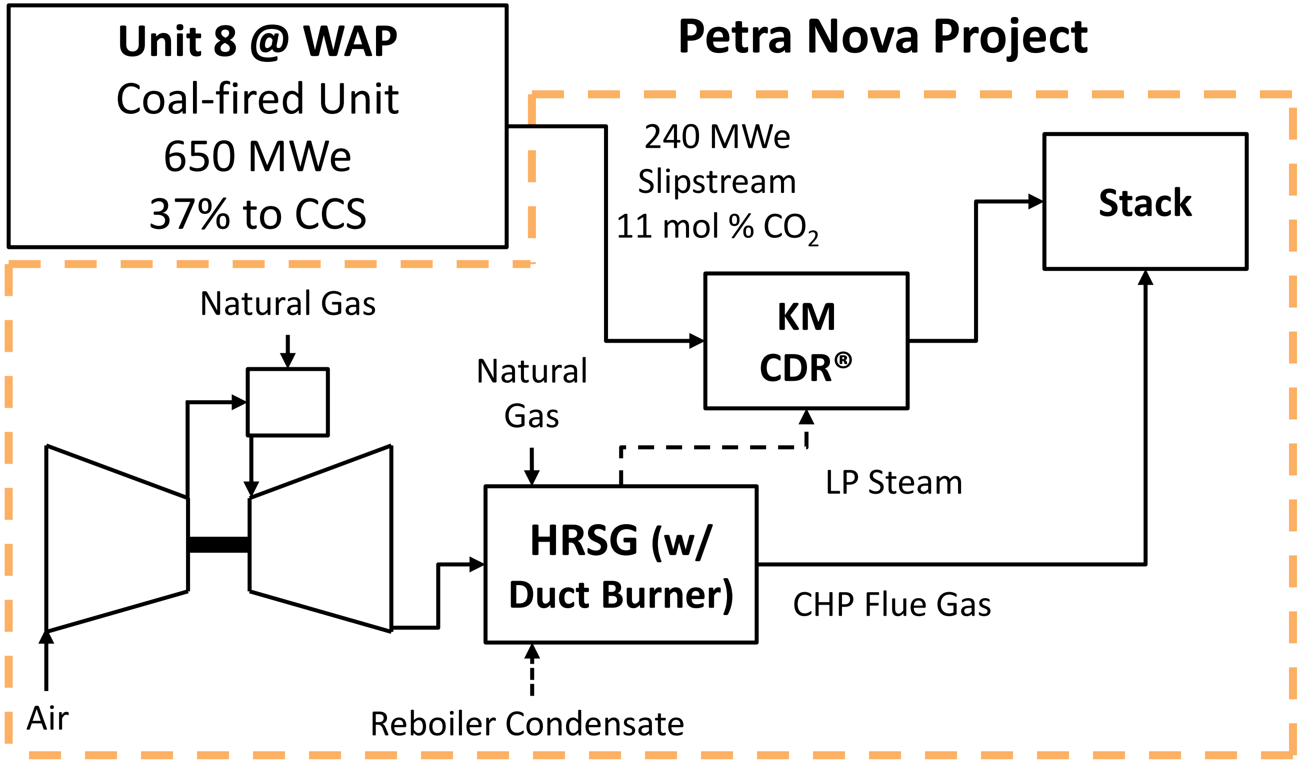
- Base case vs. w/ CCS @ same fuel input (730 MWt)
  - Gross Power: 416 MWe vs. 388 MWe
  - Net Power: 402 MWe vs. 331 Mwe
- Steam extracted from IP/LP Crossover
  - 3.22 bar @ 308 °C (attemperated to 150 °C)
  - 260 t/hr (~45% of steam in crossover)
- Capture Process
  - Shell Cansolv®
  - 90% CO_2 removal (130 tCO_2/hr)
  - Similar to Case 2 (similar flue gas spec.)
    - No FGD
    - DCC before absorber



Plant 4B – Coal-fired + CHP – Petra Nova Project

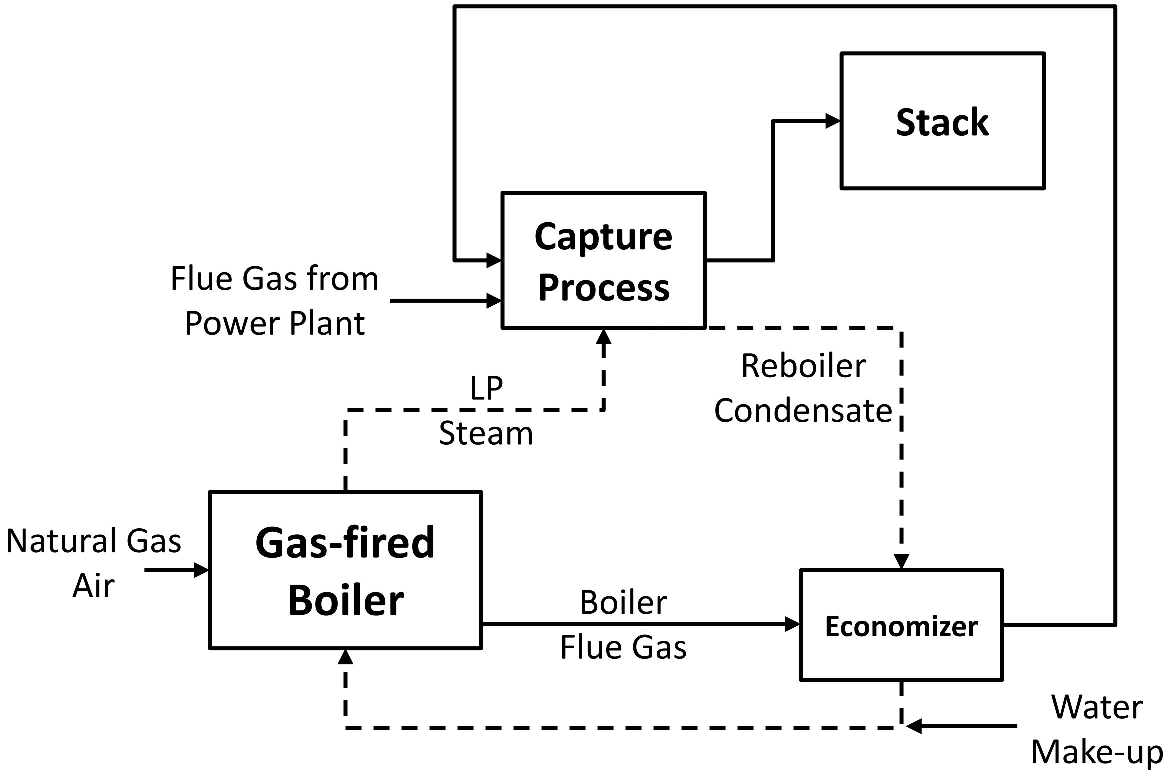
- Petra Nova Project diverted 37% of the 650MWe flue gas from Unit 8 @ WAP station to a capture plant (240MWe)
- Dedicated CHP plant
  - Power Production
    - CCS Aux Power (34 MWe) + Excess Power sold to ERCOT (51 MWe)
  - LP Steam Production for Capture Plant
    - HRSG with duct burning
- Capture Process
  - Kansai Mitsubishi Carbon Dioxide Removal Process® (KM CDR®)
  - 90% CO_2 removal on slip stream (199 tCO_2/hr)
  - No CO_2 removal from CHP unit
  - DCC to cool flue gas to ~49 °C
  - SO_2 polisher to minimize amine degradation

Basis for CHP regeneration option, but not considered a base case as <90% capture



Option C: Standalone Gas-fired Boiler

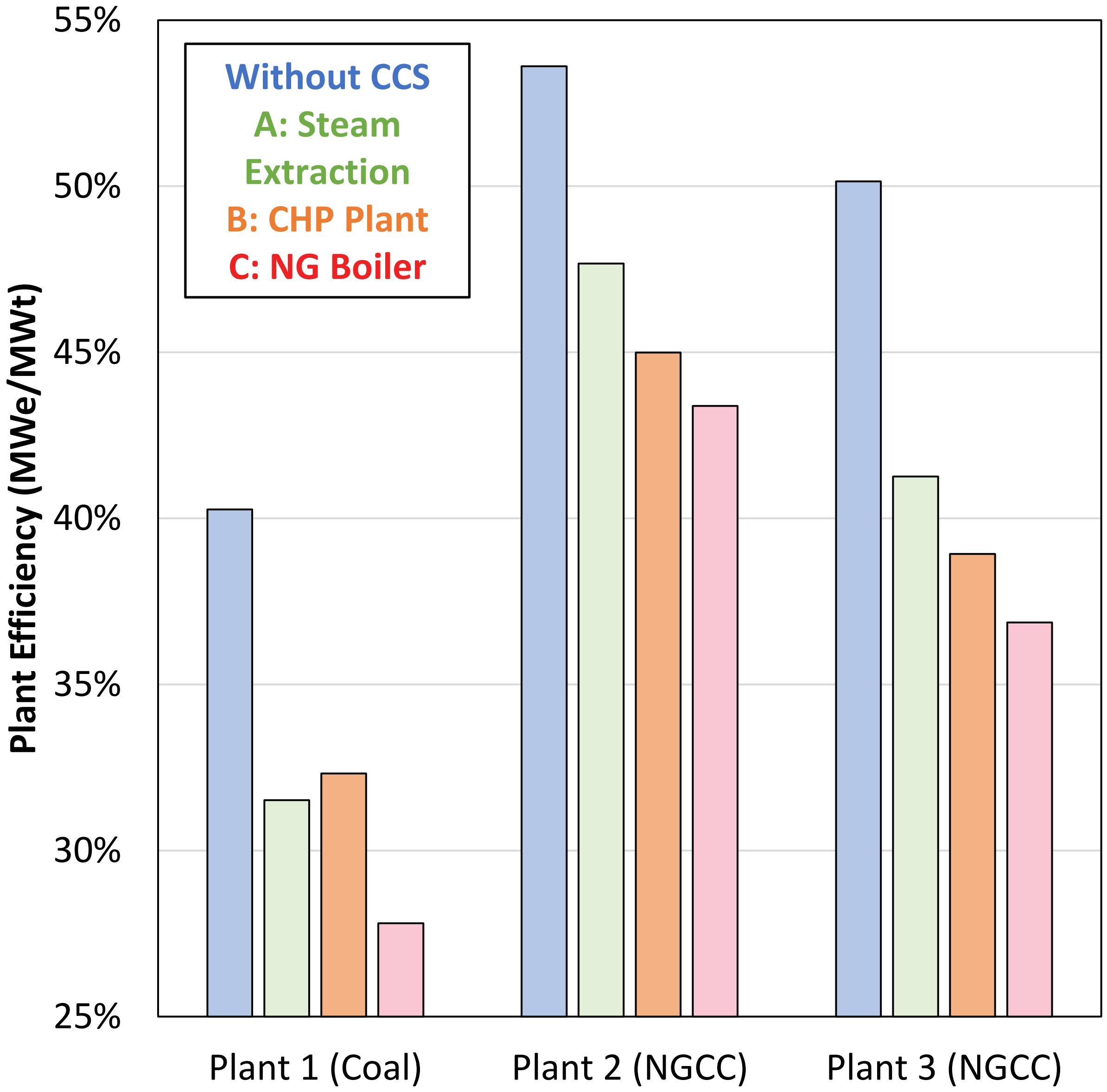
- Gas-fired boiler as a dedicated LP steam generator for the capture plant
- Boiler efficiency loss (as % of fuel input)
  - Stack loss: 8 to 35%
    - Energy lost in the flue gas
  - Blowdown loss: 0.2 to 3%
    - Energy lost in water purge
  - Shell loss: ~1%
    - Energy loss by radiation and convection
- Typical utility boiler efficiency: 85%
  - 0.85 MWt Steam/MWt HHV Fuel Input
    - With economizer, O_2 control, and well insulated
- Water withdrawal requirements
  - Depends on feedwater Total Dissolved Solids (TDS)
    - Average blowdown is ~6% of feedwater (200 ppm TDS)



Water-tube Boiler

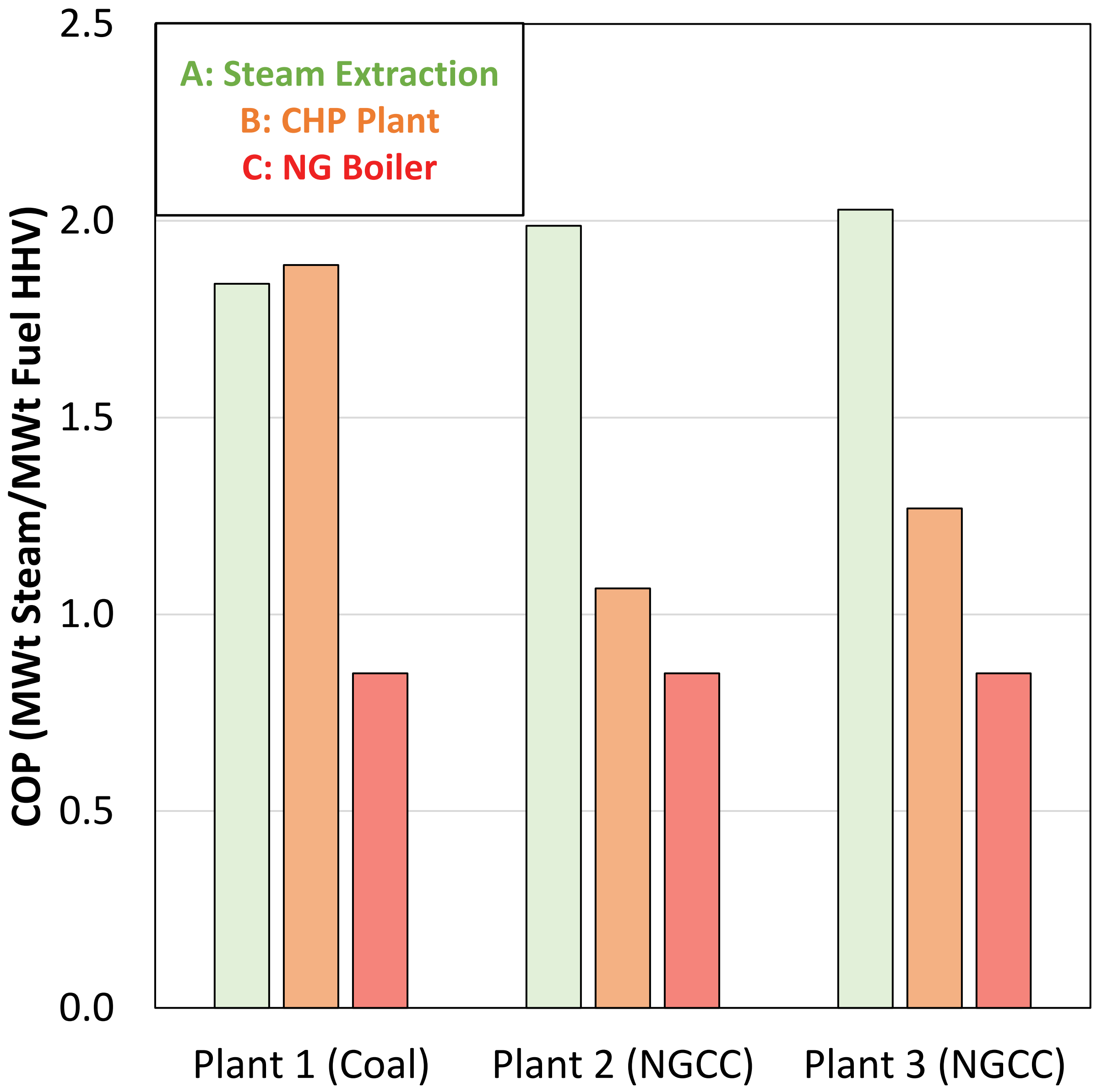
Comparison and Findings – Net Power Efficiency

- Coal:
  - CHP plant > Steam extraction > Boiler
  - 20% lower than base plant with 35-38% of the LP steam extracted to CCS
  - CHP has a higher efficiency than steam extraction because of the turbine & HSRG
  - Coal flue gas has 3x more CO_2 than NGCC flue gas
- NGCC:
  - Steam extraction > CHP plant > Boiler
  - 11-18% lower than base plant with 40-45% of the LP steam extracted to CCS



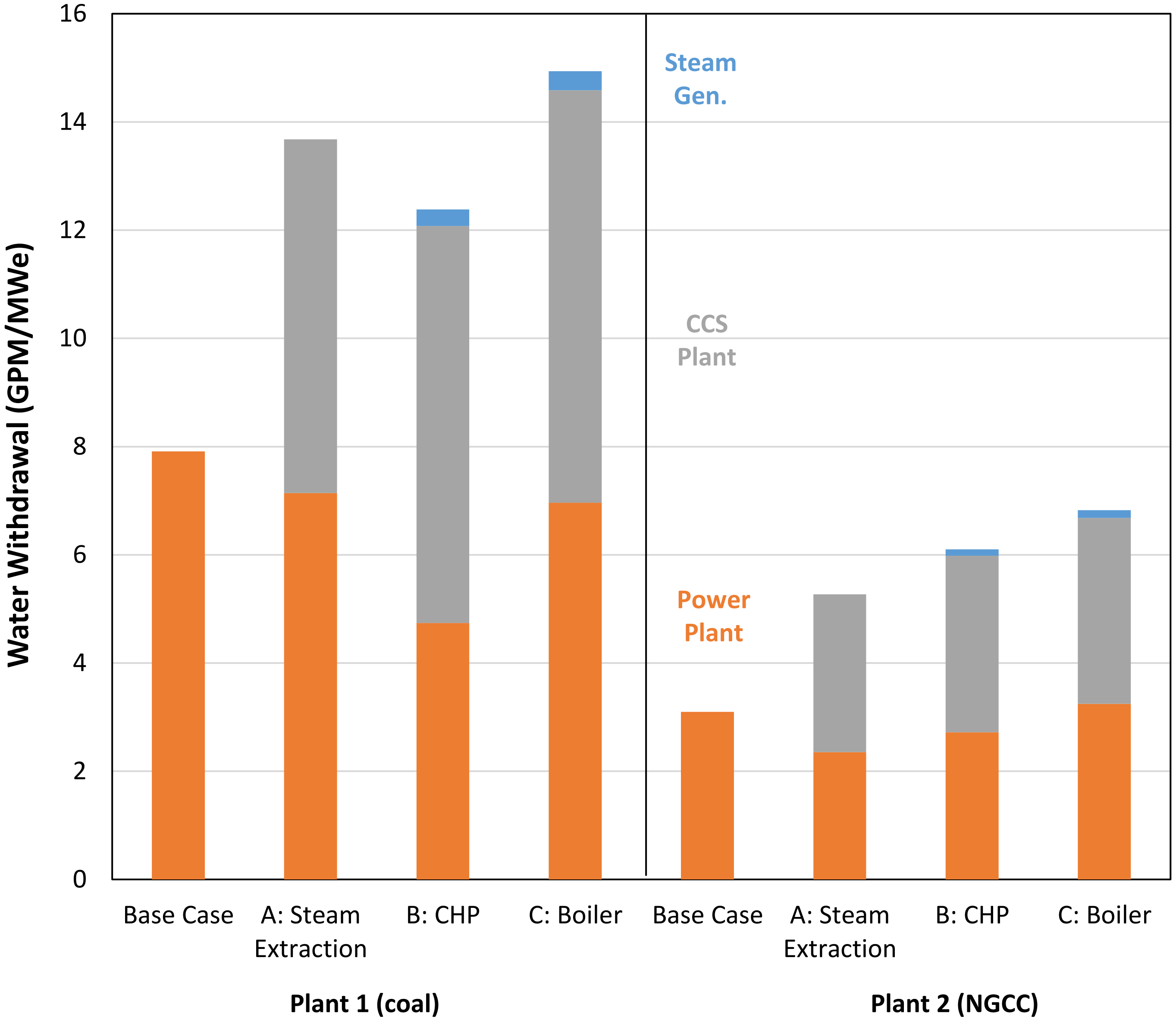
Comparison and Findings – Coefficient of Performance

- COP: MW_t steam produced for the reboiler per additional MW_t fuel input
- Coal
  - CHP > coal-fired plant with steam extraction
  - More MWt coal is required to produce the same amount of gross power as 1 MWt natural gas used in a CHP
  - COP of boiler is same as combustion efficiency, around 85%
- NGCC
  - Steam Extraction > CHP Plant > Gas boiler
  - NGCC with steam extraction has a higher COP than CHP



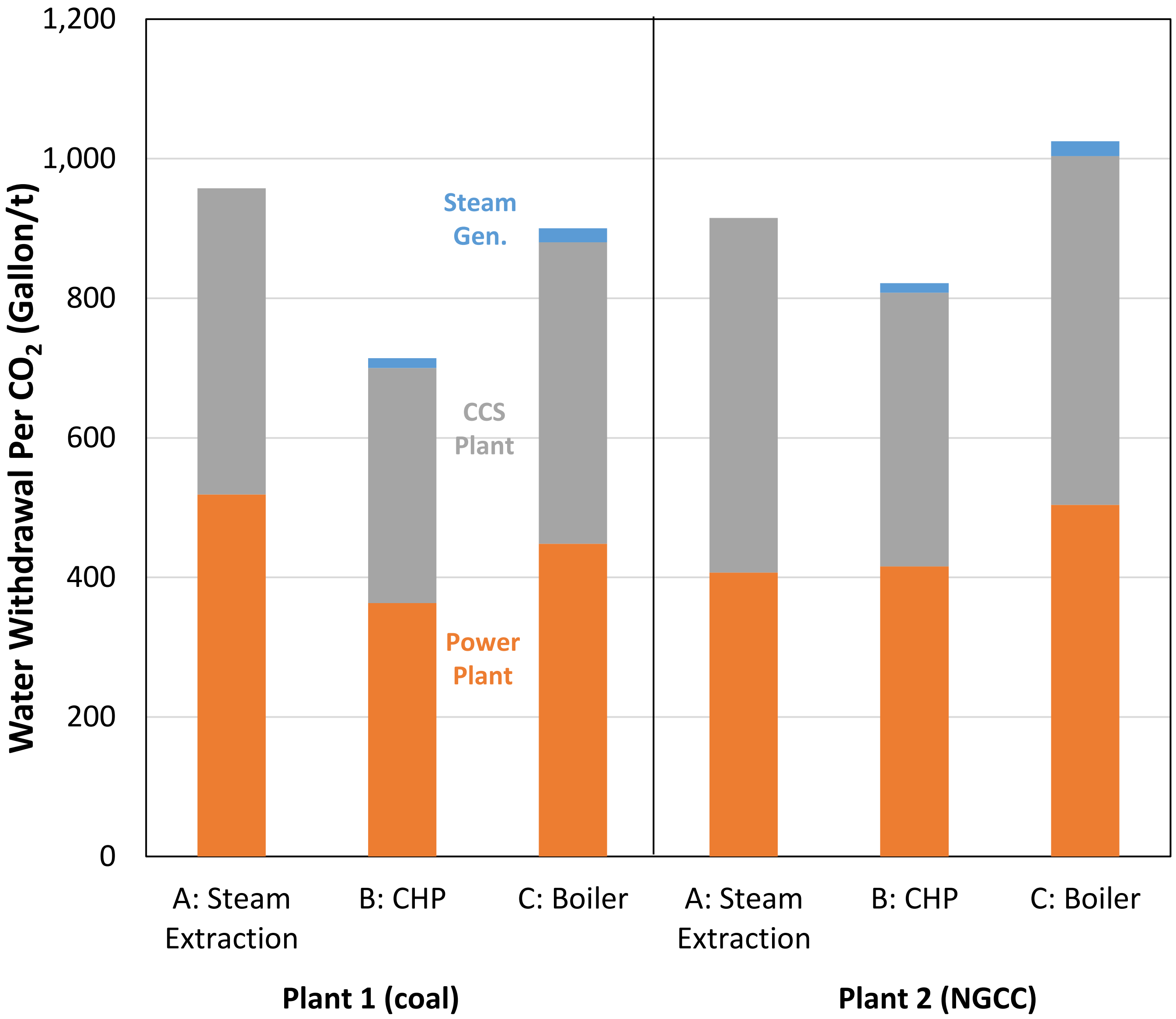
Comparison and Findings – Water Withdrawal/Power

- Coal plant uses more than twice amount of the water than NGCC
  - more electricty from superheated steam, higher condenser duty, lower power efficiency
  - Higher amount of CO_2 captured
- Capture plant approximately doubles water consumption
  - Steam extraction: cooling duty transfers from power plant to CCS plant
  - CHP: extra electricity production reduces water per power
  - Could be mitigated by using air cooling
  - Water consumption is inversely related to thermal efficiency



Comparison and Findings – Water Withdrawal/CO_2

- Coal plant uses comparable amount of water as NGCC on basis of CO_2 captured
  - Coal plant produces more CO_2
- Capture plant approximately doubles water consumption
- CHP requires least amout of waterper ton of CO_2 for coal because of additional CO_2 produced



Comparison and Findings – Capital Expenditure

- Steam extraction: potentially low cost
  - Least new equipment installation: attemporation and steam routing
  - Reduces output from base power plant (~20% for coal, 11-18% for NGCC)
  - Large risk for integration and cost uncertainty
    - Large amount of LP steam extracted (38% for coal & 40-45% for NGCC), turbine modification
    - Space limits for retrofitted plant, steam routing
    - Process integration and system control
  - Smaller CCS plant size, use existing pretreatment (SCR, FGD)
- Standalone unit: high cost, low risk
  - New equipment: turbine + HSRG/ boiler, new fuel line, exhaust pretreatement (SCR) and ducting
  - CHP increases power output
  - Larger CCS plant
  - Location of standalone exhaust feed (3.5% CHP/8% NG boiler) can be optimized.

Comparison and Findings – Flexibility and Operability

- CCS plant start-up (Based on pilot plant data from TCM)
  - Hot Start-up time: 20 min
  - Cold & hot with delayed steam: 50 min,
- Steam extraction
  - Time required during cold start-up before steam is available to CCS
    - NGCC: 6 hrs
    - Coal: 9 hrs
  - At >25% load, LP steam reaches desire T & P with reduced flowrate
- Standalone units have shorter start-up time
  - CHP: 1 hr
  - NG boiler: 0.5 hr
  - Can be started earlier separately

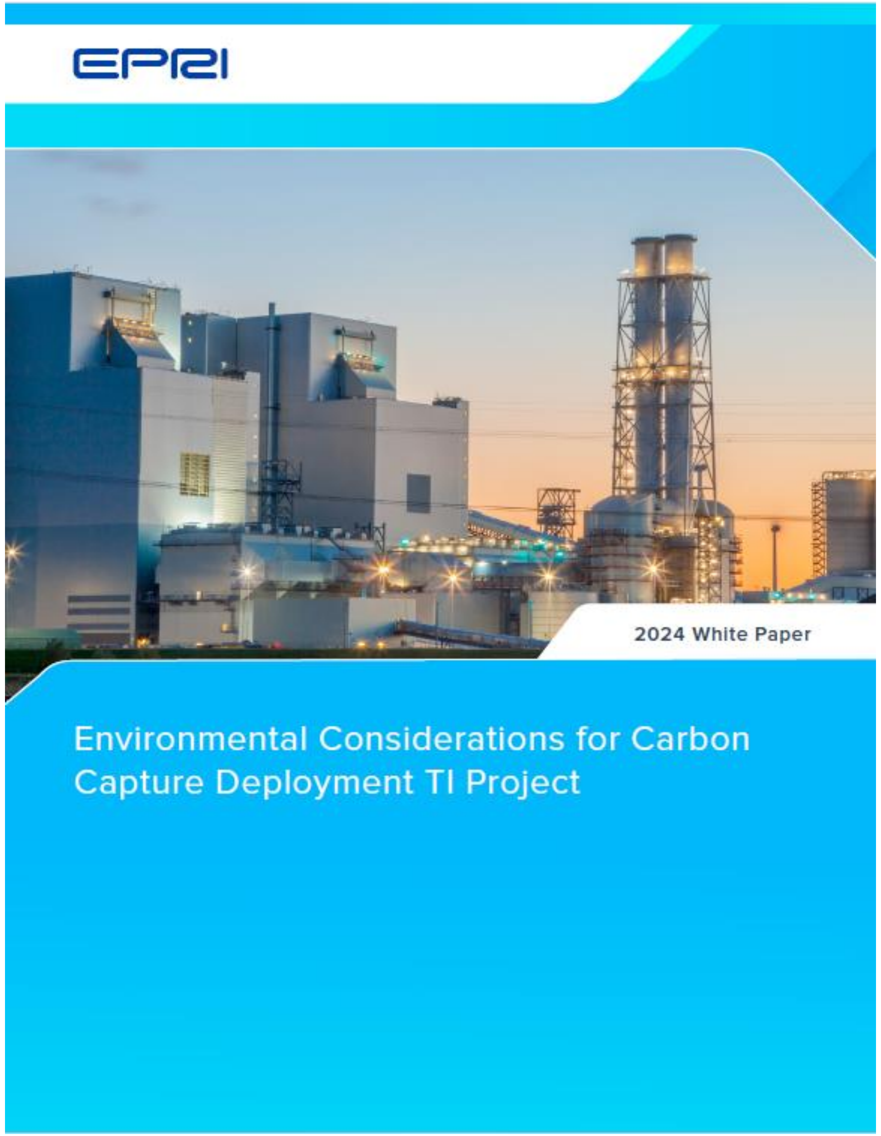
Comparison and Findings – Conclusions

- Steam extraction: efficient, potentially lower cost, higher risks, least flexible
  - Most efficient for NGCC
  - Reduces plant efficiency by around 20% (coal), 11-18% (NGCC)
  - Reduces gross power by 7% (coal) and 12% (NGCC)
  - COP around 1.8 (coal) and 2.0 (NGCC)
- CHP: efficient produces electricity, expensive
  - Most efficient for coal
  - Increases power output by 50% (coal), 10% (NGCC)
  - COP around 1.8 (coal), 1.1 (NGCC)
  - Increases CO_2 rate by 45%
- Boiler: most flexible, lower cost than CHP, lowest efficiency, highest water consumption
  - COP around 0.85
  - Increases CO_2 rate by 20%

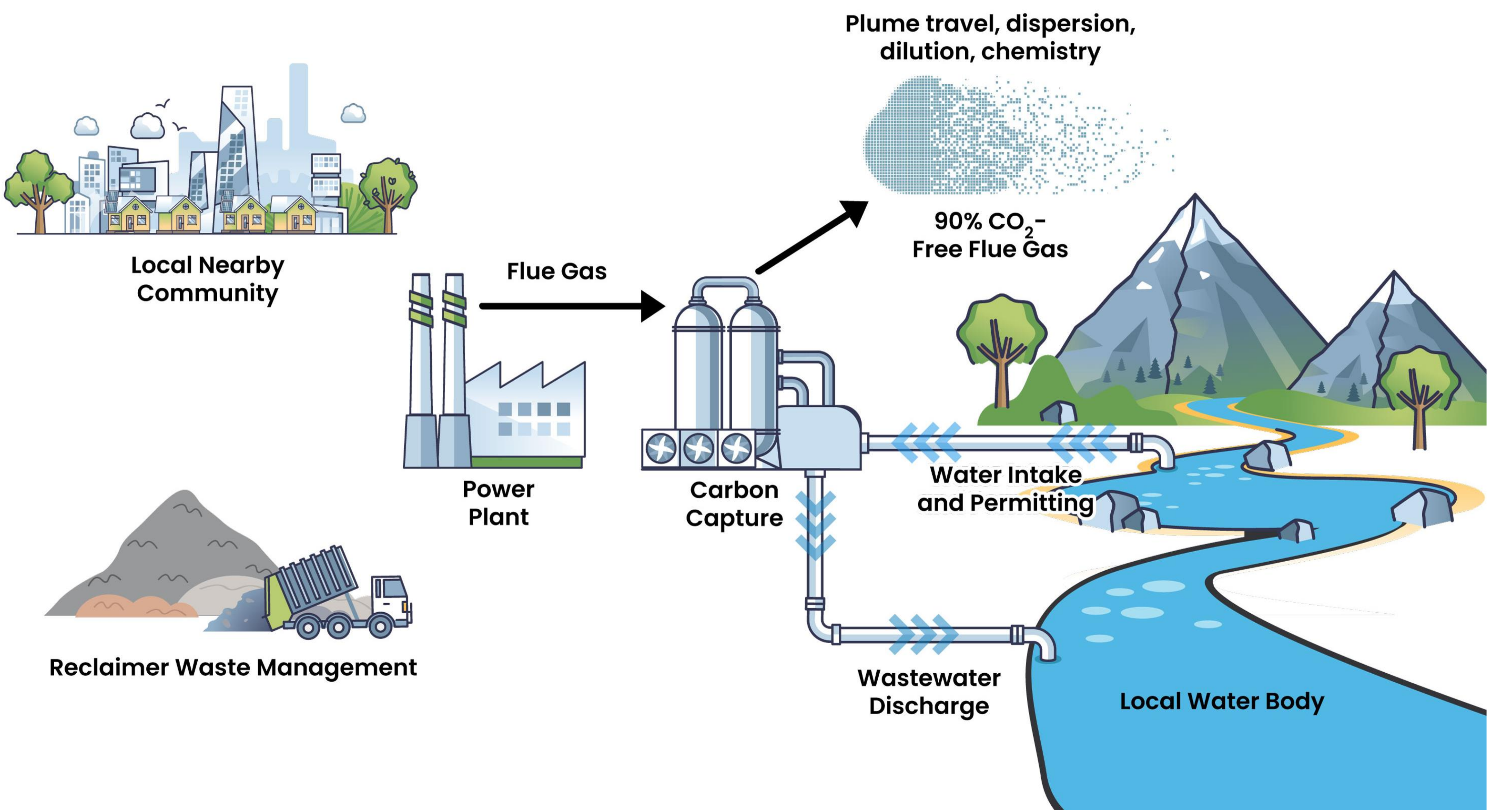
Full report: Technical Update #3002024314

Environmental Considerations

- Evaluate the environmental considerations of carbon capture to enable successful deployment
  - Air Quality
  - Water
  - Land
  - Public Engagement



Report 3002030909 (2024)

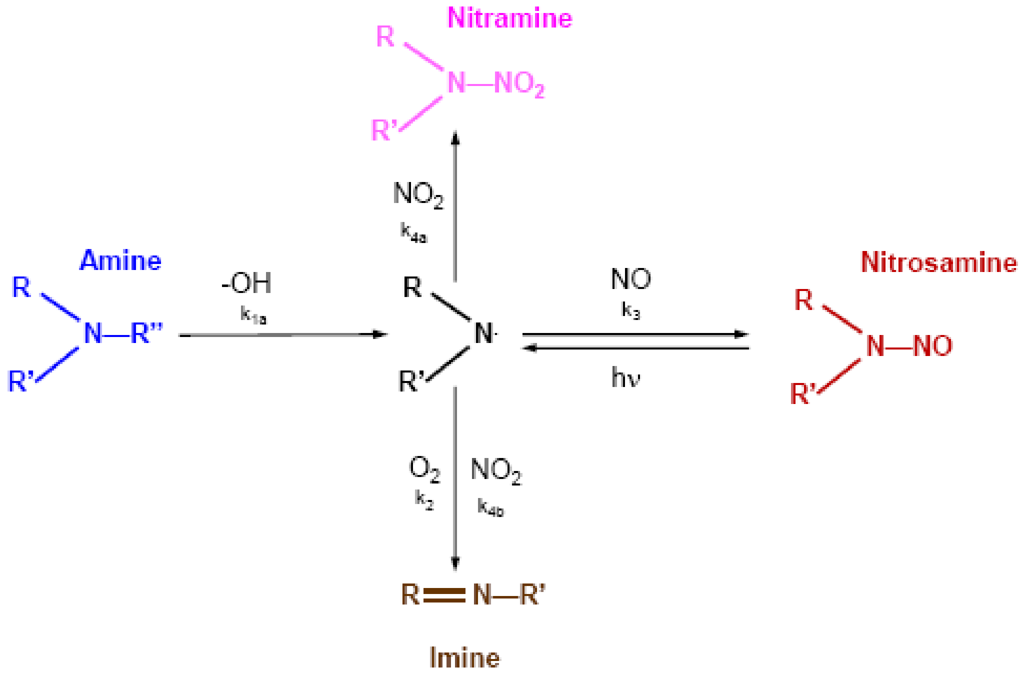


Overview of environmental considerations for carbon capture

Air Quality – Dispersion Model Selection: SCICHEM

SCICHEM: Second-order Closure Integrated Puff Model with Chemistry

- Lagrangian puff dispersion model that can handle non-linear atmospheric chemistry
- Plume represented as a succession of 3-D puffs to represent an arbitrary, three-dimensional, time-dependent concentration field

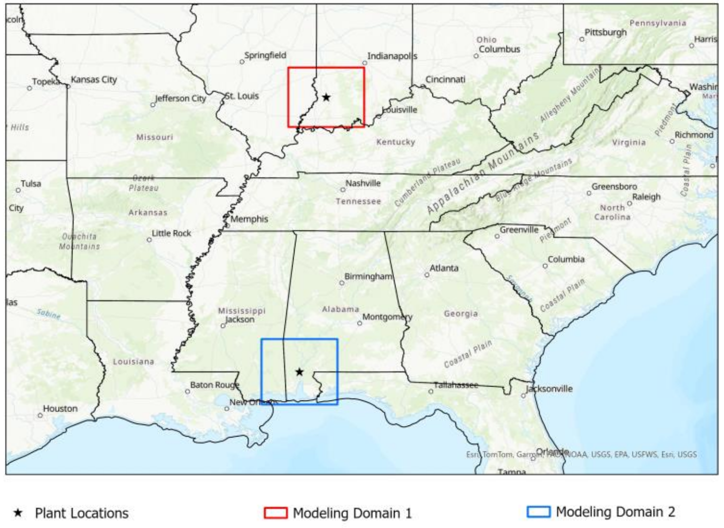


Adapted from Nielsen et al. (2012). *Chemical Society Reviews*, 41(19), 6684-6704.

EPRI-Developed Open-Source Model

SCICHEM Simulations of Emissions from Carbon Capture

- Two regions in the US
  - Mid-West and Gulf Coast
- Coal and gas-fired power plants
  - NGCC base plant as defined by case B31B[1]
  - Representative stack parameters
- 3 amines (with and without acid wash):
  - MEA, PZ, and a mix of AMP & PZ
- Annual simulations
  - Hourly resolution for reporting purposes
  - 24-hour and annual results presented



Amines
Monoethanolamine (MEA), $NH_2CH_2CH_2OH$
2-Amino-2-methylpropanol (AMP), $(CH_3)2C(NH_2)CH_2OH$
Piperazine (PZ) $C_4H_{10}N_2$

1. Cost and Performance Projections for Coal-and Natural Gas-Fired Power Plants rev 4a, 2023, NETL

Case Study

- Solvent: Piperazine (PZ)
- 3-D meteorology from EPA 2016 WRF simulation
- Background concentrations from PGM (CAMx) 2016 simulation
- No acid wash (worst-case scenario) for initial simulations
- Acid wash for sensitivity simulations
  - Conservative assumptions for removal efficiencies
  - Amine and nitrosamine removal efficiency: 95% (reported removal efficiency: 96-99% [1)])
  - Ammonia removal efficiency: 99% (reported removal efficiency: >99% [1)])
- Monthly max 24-hour values of PZ, PZ nitrosamine, PZ nitramine, PZ nitrasomine + nitramine, amine PM and total PM
- Surface receptors with 3 grid resolutions: ~4 km, ~500 m, ~250 m
  - Illustrates SCICHEM capability of resolving fine-scale features for near-source impacts

Emissions from PZ	ppm
NH_3	5
Amine	0.10
Acetaldehyde	0.05
Formaldehyde	0.005
Acetone	0.005
Nitrosopiperazine	0.01

Pilot plant demonstration of mitigating amine oxidation by dissolved oxygen removal with N_2 sparing, Fred Closmann, Pittsburgh, PCCC-7, 2023

Surface Concentrations from Gulf Coast NGCC Emissions

Pollutant	Units	Without Acid Wash		With Acid Wash	
		Max 24-Hour Average	Max Annual Average	Max 24-Hour Average	Max Annual Average
Piperazine	ng/m^3	91.2	7.79	3.95	0.34
Piperazine Nitrosamine	ng/m^3	1.17	0.05	0.06	0.003
Piperazine Nitramine	ng/m^3	0.50	0.02	0.03	0.001
Nitrosamine + Nitramine	ng/m^3	1.34	0.07	0.07	0.004
Amine $PM_{2.5}$	ng/m^3	1.09	0.02	0.73	0.02
Total $PM_{2.5}$	$\mu g/m^3$	1.2	0.05	0.28	0.007

Acid wash is below NIPH 0.3 ng/m^3

EPRI

Surface Concentrations from Mid-West NGCC Emissions

Pollutant	Units	Without Acid Wash		With Acid Wash	
		Max 24-Hour Average	Max Annual Average	Max 24-Hour Average	Max Annual Average
Piperazine	ng/m^3	74.4	3.22	3.24	0.13
Piperazine Nitrosamine	ng/m^3	0.88	0.03	0.05	0.0013
Piperazine Nitramine	ng/m^3	0.38	0.01	0.02	0.0007
Nitrosamine + Nitramine	ng/m^3	1.01	0.035	0.06	0.002
Amine $PM_{2.5}$	ng/m^3	1.9	0.03	1.05	0.02
Total $PM_{2.5}$	$\mu g/m^3$	0.82	0.04	0.34	0.008

Acid wash is below NIPH 0.3 ng/m^3

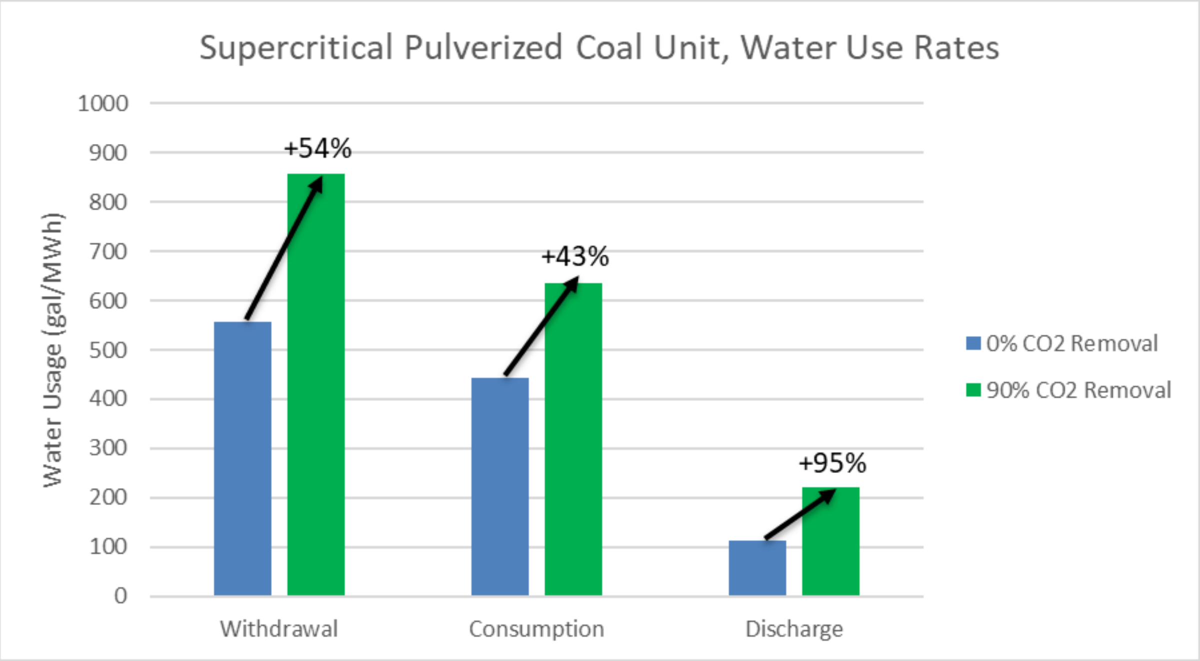
Air Quality – Summary

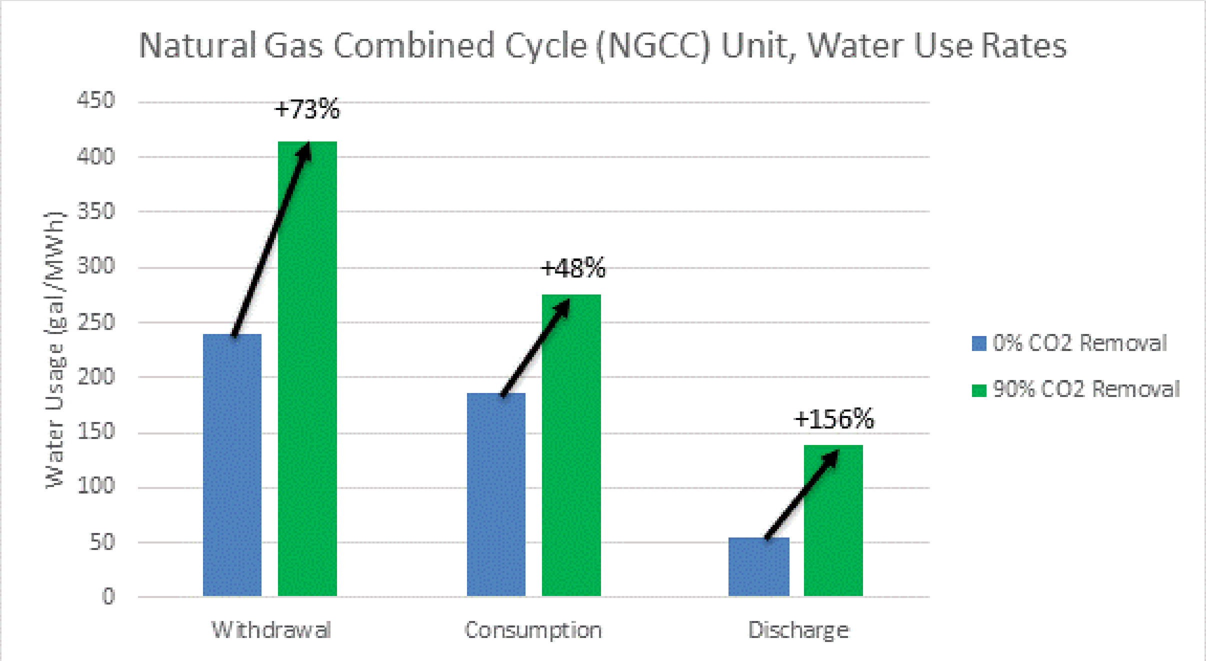
- Pilot plant case studies show that it is important to use fine-scale modeling to resolve higher concentrations near the source

- Using acid wash and a conservative assumption of 95% removal efficiency for amine and nitrosamine results in maximum 24-hour concentrations of [nitrosamine + nitramine] well below the NIPH guideline of 0.3 ng/m^3 for 10^{-5} risk

- Using acid wash and a conservative assumption of 99% removal efficiency for ammonia results in up to a factor of 4 reduction in total $PM_{2.5}$ attributable to the stack emissions from the pilot plant

Water – Consumption increases for thermally-driven capture

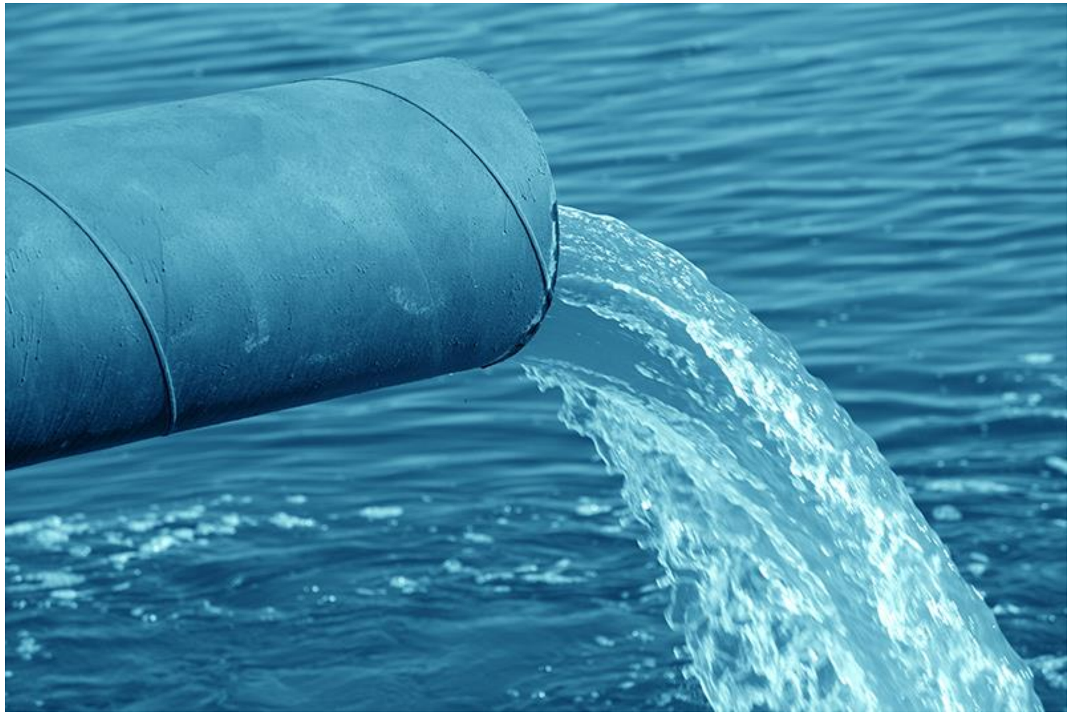




Water use rates for 650MW units retrofit with amine-based CCS

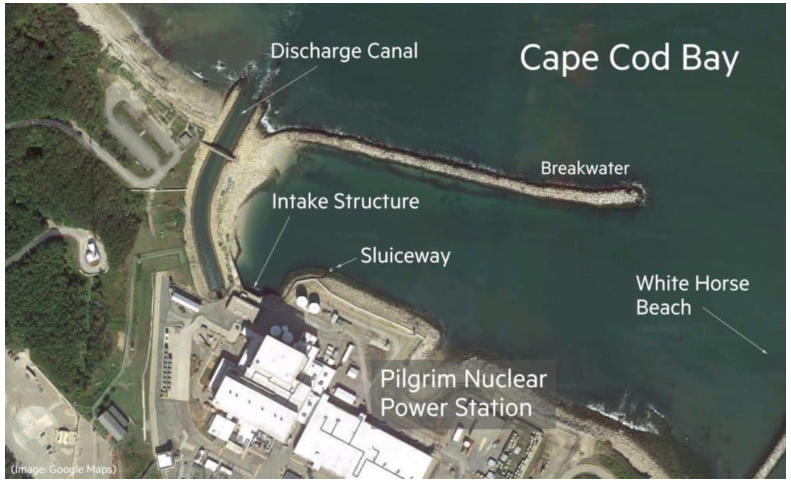
Permitting, Siting, and Regulatory Impacts

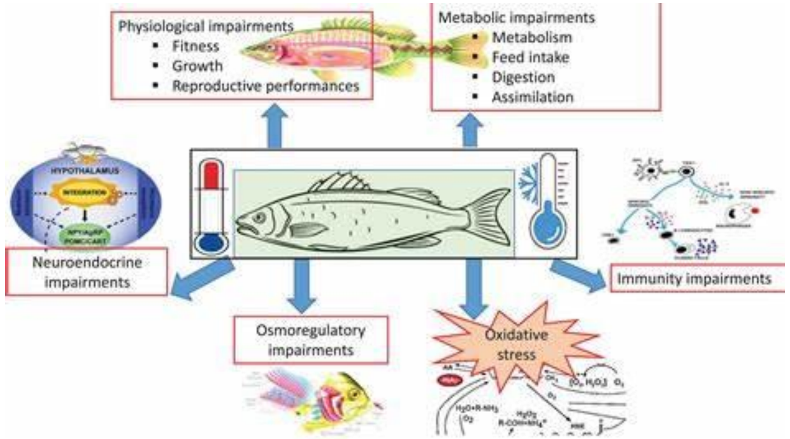
- Siting
- Water withdrawal and consumptive use
- Treatment for discharge
- Water quality and effluent impacts
- Stormwater
- Alternative water sources



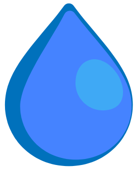
Cooling Water, Intake, and Discharge Implications

- New cooling systems may be required
- Increased flow at site intake
  - CWA Section 316(b) Rule
- Discharge requirements and limitations
- Aquatic impacts





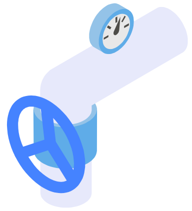
Water and Wastewater Treatment Needs



Water Treatment

Demineralized water

Cooling water



Wastewater Treatment

Water treatment and cooling tower blowdown

Direct contact cooler wastewater

Amine-rich wastewater

Reclaimer waste

Future Research Priorities – Water

- Alternative cooling approaches
- Water treatment for amine-rich wastewaters
- Potential impacts of amines on aquatic life
- Case studies on siting and permitting for full-scale CC systems

Land – How does carbon capture impact land use?

- Significant land required to deploy CC technology
  - W.A. Parish Unit 8 (Petra Nova Project):
    - Existing Unit ~ 4 acres
    - Carbon Capture Process ~ 4.6 acres
    - Carbon Capture BOP ~3 acres
  - Boundary Dam Unit 3:
    - Existing Unit ~ 1 acre
    - Carbon Capture ~ 2 acres
  - Shand Unit 1:
    - Existing Unit: 3 acres
    - Carbon Capture: >3 acres
- *CC may require up to double area of the existing unit*

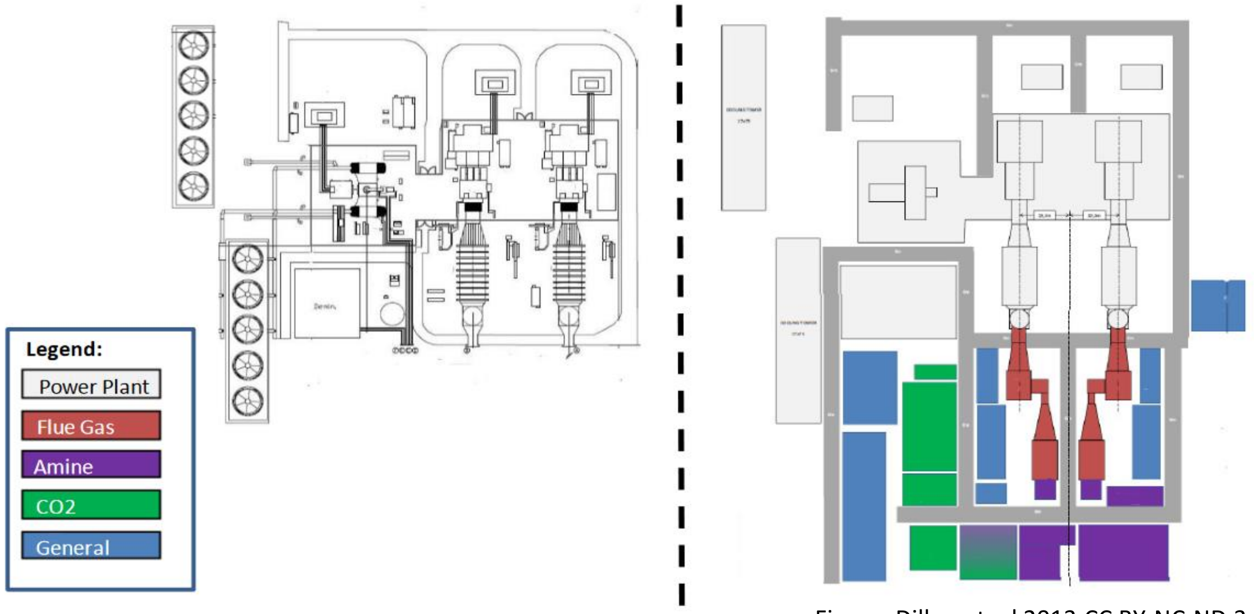
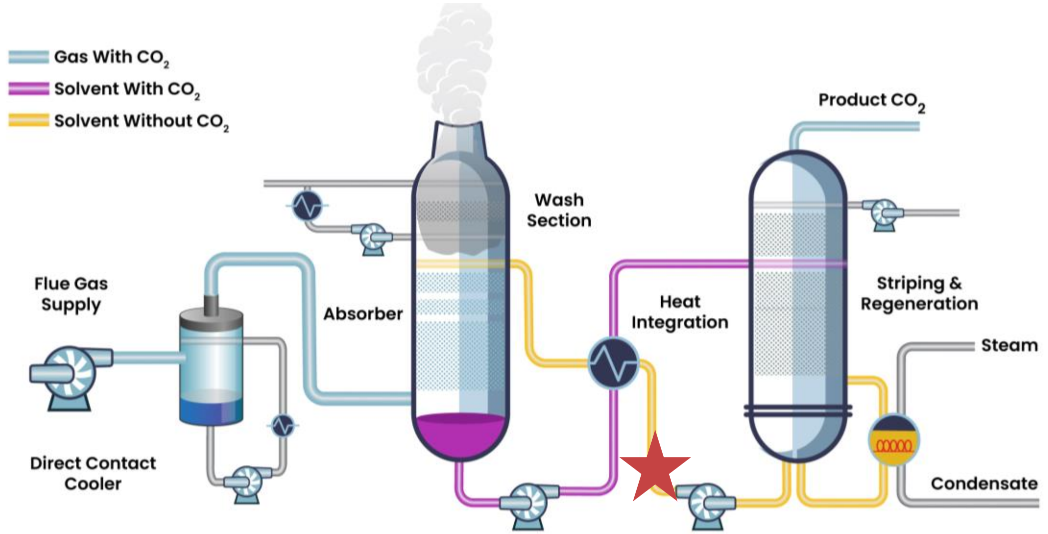


Figure: Dillon et. al 2013 CC BY-NC-ND 3.0

- Potential impacts of adding CC
  - Loss/reduction of existing property buffers
  - Acquisition of additional land
  - Introduction of new sources of nuisances
    - Odors
    - Noises
    - Aesthetics

What about waste management?



- Solvent reclaimer is main source of waste
- Reclaimer removes:
  - heat-stable salts
  - non-volatile organic compounds
  - suspended solids

- 3 categories of reclaimer processes
  - thermal (distillation) ~ primary approach to date
  - non-thermal (ion exchange, electrodialysis)
  - advanced non-thermal (electromagnetic, solvent extraction)
- Waste Classification
  - Some thermal technologies at coal site produce hazardous waste under US regulations due to metals content
  - Many technologies produce hazardous waste under EU regulations due to residual solvent content
- Potential Beneficial Use
  - Energy recovery (co-combustion / incineration)
  - Ammonia / urea replacement

Reclaimer technology controls waste classification, disposal, beneficial use

Public Engagement – Carbon Capture

Although CCS has existed for several decades, it remains relatively unfamiliar to the public.

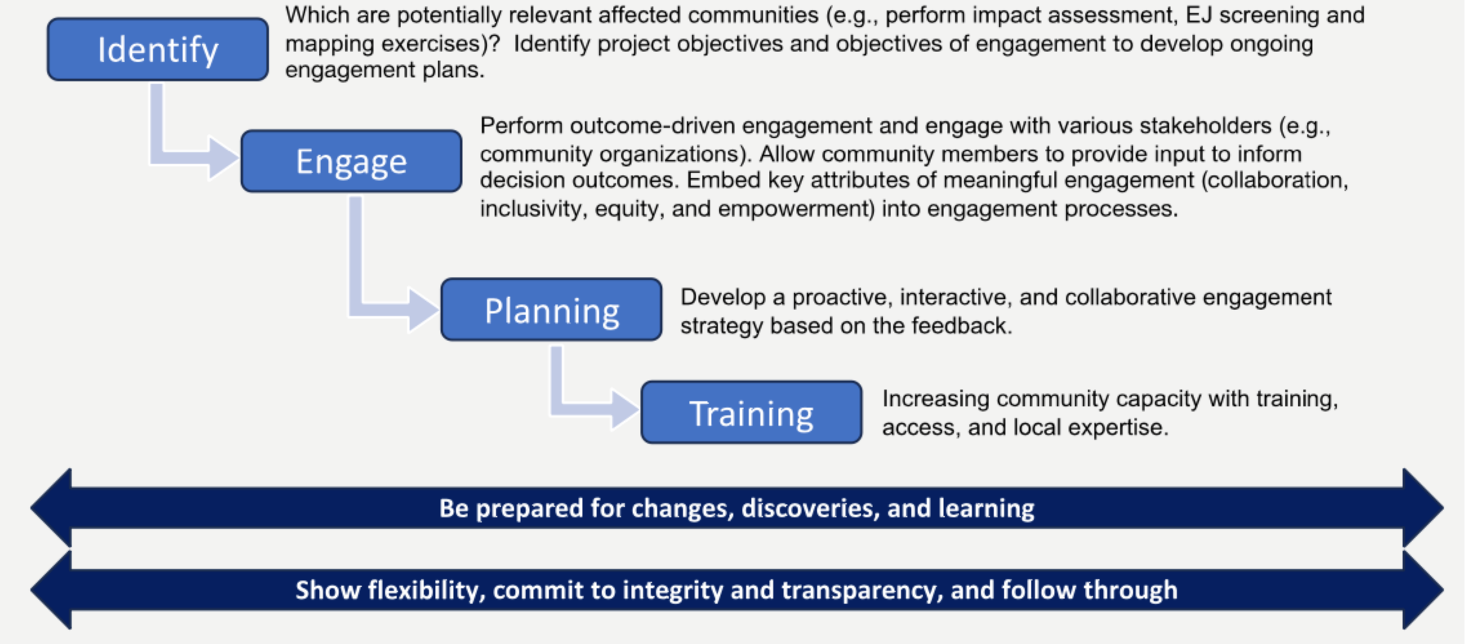
Common EJ issues discussed include property values, public health, water scarcity, and the polluting facilities' operational life associated with CO_2 leakage as well as increased energy consumption.

Key Considerations

- Direct and transparent communication between the developer and the community, including clear discussions about the unknowns, is essential
- Understanding general risks and mitigation strategies is certainly important, but emphasizing community-specific communication methods, training, and education at various project stages is also necessary.
- Developers should communicate technical information in a manner community members easily understand and provide all materials and information in the community's spoken language.
- Maintaining an open line of communication that encourages and accommodates continuous two-way dialogue is key.

Best Practices for Engaging Communities

- **Holistic Perspective**: Environmental justice must be examined from multiple angles, considering a variety of factors to ensure comprehensive understanding and action.
- **Long-Term Benefits**: While addressing EJ concerns may seem like additional work, it is crucial for ensuring a smooth development process and sustainable operations. Think of it as delivering long-term benefits to all stakeholders.
- **Stakeholder Engagement**: Emphasize the importance of participatory planning over top-down decision-making for new projects. Engaging stakeholders in the planning process leads to more effective and equitable outcomes.



Workforce

- Implementing CCS at existing coal-fired power plants would provide an opportunity to provide equity to the portion of the workforce potentially displaced by coal- and gas- fired power plant closures.
- CCS offers long-term benefits to the direct workforce by preserving jobs, maintaining wages, and eliminating the need for relocation and construction at the site creates short-term jobs.

Table 3. *Estimated employment impacts of adding a CC system to a 550MW natural gas combined-cycle power plant [76]*

IMPACT	ANNUAL EMPLOYMENT
Direct, indirect, and induced construction phase jobs (3 years)	3890
Direction, indirect, and induced operations phase jobs (20 years)	217

Key Takeaways

Addressing EJ Concerns: Effectively addressing environmental justice (EJ) concerns ensures a smooth development process and long-term benefits for all stakeholders.

Public Awareness of Carbon Capture (CC): Despite its long existence, CC remains unfamiliar to the public, raising concerns about CO_2 management and infrastructure use. Public education and training can provide more accurate perspectives on EJ considerations related to CC.

Holistic Perspective and Cumulative Impacts on Communities: Growing attention is being paid to the cumulative impacts on communities where multiple environmental hazards and social disadvantages converge. However, the methodological approach to researching these impacts is still limited.

Job Security through CC Implementation: Implementing CC at coal plants can offer job security for workers facing displacement due to plant closures.

Topics

- Integration
- Environmental Considerations
  - Air Quality
  - Water
  - Land
  - Public engagement
- Other areas?

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IEAGHG

ieaghg.org
+44 (0)1242 802911
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IEAGHG, Pure Offices, Cheltenham Office Park,
Hatherley Lane, Cheltenham, GL51 6SH, UK

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