2023 THOUGHT LEADERSHIP

THE INVESTMENT CASE FOR CCS: POLICY DRIVE AND CASE STUDIES

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1.0 EXECUTIVE SUMMARY

Policy and regulatory developments in key geographies to reduce GHG emissions have been significant in the past two years.

Notable is the 2022 Inflation Reduction Act (IRA) in the US that provides subsidies for captured and geologically stored CO_2 and the production of clean hydrogen, and the EU's Fit for 55 package that is accelerating the phase-out of free allowances and providing support for the EU ETS carbon price.

The result has been an exponential increase in the announcement of Carbon Capture and Storage (CCS) investments.

This report summarises the available policy tools that would make CCS investments commercially viable after the developments in the past two years, and the Global CCS Institute's financial analysis of three case studies: clean hydrogen production in the US Gulf Coast, Midwest hubs, and a CCS retrofit in power generation.

This high-level analysis shows attractive returns on investment in the mid-teens due to the recent policy push.

Stacking and combining multiple revenue streams provides support for financial returns:

- Clean hydrogen projects benefit from production tax credits in the IRA in the US and carbon pricing in Europe or support for hydrogen in Japan and South Korea
- Midwest CCS hubs benefit from tax credits and the California Low Carbon Fuel Standard (LCFS) carbon market
- Low-cost loans from the state boost returns of a CCS retrofit on a coal-fired power plant in North Dakota

To quantify, these multiple streams imply a carbon price of $90 - $200 enabling these returns.

The final investment decisions expected in 2024, awaiting treasury guidance on subsidies, present an opportunity for the CCS industry to demonstrate how it can be effectively used to reduce GHG emissions, accelerate learning and spur innovation to shift the cost curve.

Deployment of CCS should enable policymakers to provide policy support beyond production subsidies to ensure long-term durable demand for CCS, such as carbon pricing, and mandates for the gradual elimination of emissions.

Such policies would increase the urgency to decarbonise and accelerate the corporate decision-making process and also de-risk the CCS value chain and bolster the investment case, unlocking the capital flows necessary for scale deployment.

This inaugural study presents the investment case for CCS applications and provides insights into what is necessary to accelerate capital flows. It also highlights the associated risk factors.

2.0 KEY TAKEAWAYS

1. CCS is a vital and cost-effective abatement technology, but defining its economic value compared with freely emitting CO_2 requires policy and regulation.

2. Policy support in key jurisdictions drives interest in the CCS projects with the lowest-cost applications. The announced projects at the time of writing have the potential to sequester more than 100 million tonnes of CO_2 by 2028 in the US alone.

3. The returns investors are betting on depend on multiple sources of revenue streams in addition to the IRA production subsidies in the US.

4. Policy and regulation surrounding permitting and gaining community acceptance is necessary to mitigate risks and accelerate deployment. Development of insurance and tax equity markets is also critical for deployment in scale.

5. For clean hydrogen, the carbon price in the EU and demand support in Asia make the commercial case: Almost all clean hydrogen and ammonia projects in the US depend on foreign demand and long-term offtake agreements.

6. For Midwest CCS hubs with low-carbon ethanol as their backbone, tax credits, the blend mandate and LCFS carbon credits are driving demand, but cost and time overruns are risk factors.

7. CCS in power generation can reduce emissions significantly. The Institute's high-level project economics analysis of Project Tundra, a CCS retrofit on a coal-fired power plant, is promising.

8. Clean ammonia projects benefit from an implicit carbon price of around $200 through stacking IRA subsidies and EU carbon pricing. Combining IRA subsidies and the LCFS price for ethanol hubs is tantamount to a carbon price of between $100 and $200.

9. The deployment of CCS applications provides an opportunity for the industry to demonstrate effectiveness and accelerate cost reductions and for policymakers to build on the momentum to ensure long-term demand.

10. The lack of visibility beyond the 12-year IRA subsidy duration is suboptimal for infrastructure assets with an economic life of 25 years or more.

11. CCS deployment at the scale needed requires long-term demand drivers in addition to supply-side subsidies. Policy tools like carbon pricing and emission mandates increase the urgency for emitters to take the carrots on offer.

12. The recent changes to EU ETS trading scheme and proposed US EPA rules for power plants are steps in the right direction.

3.0 THE ECONOMIC VALUE OF CCS

CCS routinely faces one fundamental question from financiers and project developers: How can it be economically viable and investable?

CCS is a mature abatement technology, but it has little economic value compared with freely emitting CO_2 into the atmosphere, and that calculus can only change with policy and regulation.

The cost of GHG emissions – climate change, surging insurance and disaster relief costs, loss of life and property – are increasing rapidly, becoming visible and felt by every society. Yet the emissions costs are dispersed, unevenly distributed, and back-ended, while abatement costs are front-ended. Governments face the classic economic problem of internalising negative externalities to incentivise removing emissions.

In simple terms, the challenge is how to reflect the cost of GHG emissions in prices, so a low-carbon product is cheaper than its high-carbon substitute. This would drive the demand for abatement technologies and enable its applications to earn a profit – a powerful incentive.

A policy toolbox for creating economic value from CCS primarily includes:

- emission trading systems (cap and trade, carbon offsets, baseline carbon credits)
- carbon taxes
- direct or indirect subsidies such as tax credits, provision of loans, grants or loan guarantees, and
- command and control mechanisms that mandate the phased elimination of emissions

All four mechanisms are designed to increase the cost of emissions to emitters or decrease the cost of abatement and can drive demand for CCS applications.

Policies that drive demand for CCS:

POLICY TOOL	MECHANISM	POTENTIAL TO DRIVE DEMAND FOR CCS
Carbon markets (cap and trade or baseline)	Increases the cost of emissions	Up
Carbon tax	Increases the cost of emissions	Up
Subsidies/ grants for abatement	Decreases the cost of abatement	Up
Command and control	Mandates abatement	Up

Table 1: Policies that drive demand for CCS

Governments, policymakers and regulators have accelerated the design and implementation of these policy tools in the past two years, especially in the developed world where there are more resources. In the US, the policy choice is skewed towards direct and indirect subsidies for CCS and producing clean energy; in European countries it can be a combination of carbon pricing and production subsidies; and in Japan, it is a mix of demand subsidies for clean energy and early phases of carbon pricing.

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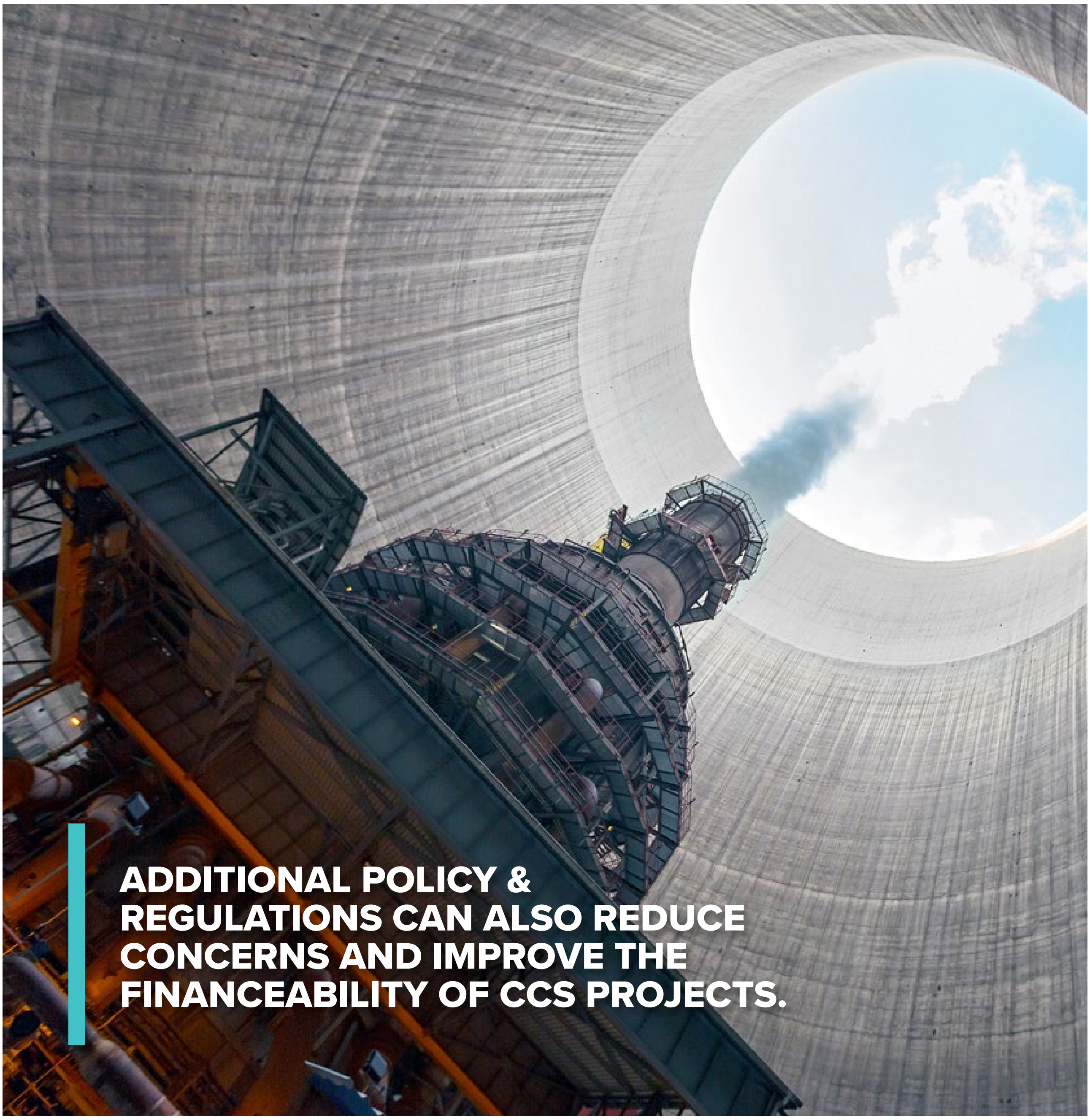


Risks vs returns

Financial institutions, whether commercial banks, pension funds or infrastructure funds, take into consideration the potential risks and returns of a project; elimination or reduction of a risk factor is converted to a higher value for the project, or vice versa.

Hence, a policy designed to incentivise investment should consider not only rates of returns but also the associated risks. This is especially true for capital-intensive long-term infrastructure projects. Some of the risks include the viability and durability of a long-term demand driver, cost and time overruns, execution, permitting, political, and liability risks.

Additional policy and regulations, such as those surrounding permitting, and gaining community acceptance, can also reduce concerns and, in turn, improve the financeability of CCS projects.

4.0 KEY POLICY DRIVERS

4.1 United States

Inflation Reduction Act of 2022

Even before the Inflation Reduction Act of 2022 (IRA), the new US administration gave signs of policy support and commitment with the re-joining of the Paris Agreement to reduce emissions. In July 2021 the Department of Energy's Office of Fossil Fuel officially added "Carbon Management" to its name, next the Infrastructure Investment and Jobs Act (IIJA) of 2021 authorised $12 billion in grants, loans, and loan guarantees for industrial emissions reduction, carbon capture, transport and storage permitting and Direct Air Capture (DAC) and $8 billion for hydrogen hub development.

These developments were dwarfed by the *IRA*, an ambitious piece of legislation that aims to decrease GHG emissions by 50% to 52% below 2005 levels by 2030 in line with the country's nationally determined contribution (NDC). The IRA relies heavily on investment and production tax credits and low-cost government loans. Tax credits can be subtracted from corporate income taxes, so effectively, they are a subsidy. The tax credits relevant to CCS are 45Q, 45Z, and 45V.

The 45Q tax credit

The IRA boosted the 45Q tax credit for the capture, geological storage and utilisation of CO_2.

The duration of 45Q is 12 years from the time the equipment starts service (but construction must begin before 2033). The entity capturing CO_2 and receiving the tax credit can transfer the tax credit to another entity easing monetisation.

Guidance issued by the Treasury on *14 June 2023* on transferability was received positively by the industry. The IRA also provided an option to receive the 45Q tax credit as a direct payment for five years for for-profit and for 12 years for tax-exempt entities, making monetisation easier.

ACTIVITY		BEFORE IRA (IN $ PER TONNE OF CO_2)	AFTER IRA (IN $ PER TONNE OF CO_2)
Geological storage of CO_2	From power generation and industrial facilities	50	85
	From direct air capture (DAC) facilities	50	180
Utilisation of CO_2	From power generation and industrial facilities	35	60
	From DAC facilities	35	130

Table 2: Increases to the 45Q tax credit from the Inflation Reduction Act of 2022

The 45V tax credit

The IRA introduced the 45V tax credit, paid per kg of clean hydrogen production. The value depends on its lifecycle production emissions intensity, with the highest value being $3 per kg of hydrogen for emissions intensities of less than 0.45 $kgCO_2e/kg$ H2 over a 10-year period. The maximum emissions intensity is 4 $kgCO_2e/kg$ H2 for eligibility. A project can claim 45Q or 45V but not both.

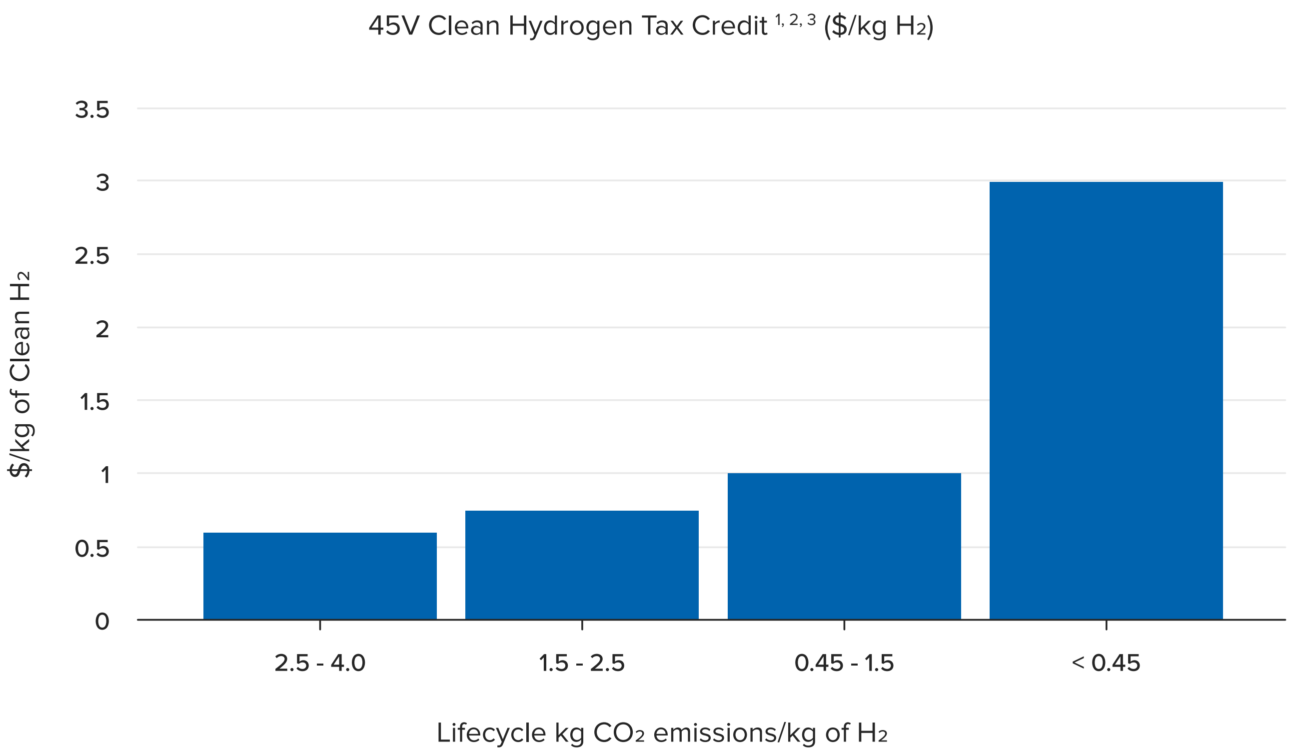


Figure 1: The value of 45V depending on carbon intensity of clean hydrogen

The 45Z tax credit

The IRA expanded the scope of the 45Z tax credit for clean transportation fuels, mainly ethanol. 45Z is $0.02 per gallon of clean transportation fuel for each point of reduction in the carbon intensity score below 50 as measured by CO_2kg per gallon. 45Z has strict time limits and is available for 3 years, from 2025 to 2027. Unlike 45Q and 45X, 45Z does not have direct pay optionality.

Title 17 Clean Energy Financing

The IRA has increased the financing capacity of the *Title 17 Clean Energy Financing Program* to $300 billion in loan guarantees up to 80% of project costs. The cost of the loan guarantee is a 10-year treasury interest rate plus 0.375%.

The program is managed by the Department of Energy's (DOE) Loan Programs Office (LPO) and has two sections: Section 1703 with some $40 billion capacity includes projects under the Innovative Energy, Innovative Supply Chain and State Energy Financing Institution categories and Section 1706, which covers Energy Infrastructure Reinvestment projects and has a capacity to provide loan guarantees of up to $250 billion. CCS, as a versatile technology with many applications, is eligible for loan guarantees under either section.

States' LCFS, cap and trade

The Low Carbon Fuel Standard (LCFS) is a compliance baseline carbon market in California. Oregon, Washington State and British Columbia have similar *legislation* and other states are expected to launch their own LCFS programs. LCFS encourages the usage of transportation fuels with a lower carbon intensity based on a fuel's lifecycle emissions over time. This includes fuel production, transportation, and combustion. Each fuel score is referenced to an annually declining benchmark. Lower CI fuels generate credits while higher CI fuels generate deficits. California has a CCS Protocol under its LCFS which allows for emission reductions through CCS that can be outside of the state if the fuel is used in California.

California also has a compliance cap and trade program, a key element of the state's strategy to reduce emissions. The program establishes a declining limit (cap) on GHG emissions covering approximately 80% of the state's GHG emissions. The California Air Resources Board (CARB) creates allowances (a tonne of CO_2 emission) equal to the cap and auctions them at an increasing floor price. The declining cap and the floor price aim to create a stable price to incentivise emissions reduction.

1. Wage and apprentice requirements apply
2. Mutually exclusive with 45Q
3. For 10 years

Emission reductions by CCS is not yet covered by California's cap and trade, however the Institute's engagement with the corporate sector suggests that CARB is working to include CCS. When and if that happens, California's cap and trade will provide an additional revenue stream for CCS applications.

4.2 European Union

The EU's decarbonisation effort has several pillars: The Emission Trading System (EU ETS), a compliance cap and trade carbon market, newly developed mechanisms like Carbon Contracts for Differences (CCfD), the EU Innovation Fund -- mainly funded by the auctioning of EU ETS allowances -- and the Carbon Border Adjustment Mechanism, effectively a carbon duty for imports from countries that lack a carbon pricing or tax mechanism.

Individual countries also have separate mechanisms to support emission reductions and CCS investments.

EU Emissions Trading System

Dating back to 2005, Europe's climate policy cornerstone is the *EU ETS*, the world's first and largest carbon market covering the EU and Norway, Iceland and Liechtenstein. It is based on a cap-and-trade principle, which sets a cap for the covered GHG emissions and lets operators trade the allowances: The cap is reduced over time to reduce emissions and participation is mandatory for covered sectors. The EU ETS covers about 40% of total emissions. CCS is included in the EU ETS; captured and permanently sequestered CO_2 in line with the European Commission's CCS directive is considered not emitted.

The allowances are either auctioned or allocated for free. The free allocation is meant to protect the competitiveness of regulated sectors and to safeguard against carbon leakage -- the migration of production to other countries with no or less stringent emissions reduction requirements.

Up until the recent reform of the EU ETS, there were too many free allowances resulting in a low EU ETS carbon price, and thus the impact on emission reductions has been limited.

The presentation of the European Green Deal in December 2019, a package of policy initiatives aimed at reaching carbon neutrality by 2050 framed as a new economic growth policy, signaled the EU's stronger policy response. The proposal and then passage of the European Climate Law and Fit for 55 package (13 legislative proposals except for REDII, Revision of Gas Directive and Regulation), significantly reduced free allowances, leading to a fourfold increase in the carbon price and stabilisation despite major geopolitical shocks like the Russia-Ukraine war and Covid-19 pandemic.

Fit for 55

Released in July 2021, the Fit for 55 package aimed at updating European climate and energy policies to align them with the EU's new target of reducing GHG emissions by at least 55% by 2030, as defined under the European Climate Law. Among the 13 legislative proposals submitted were a revision of the EU ETS Directive and the establishment of a carbon border adjustment mechanism.

In April 2023 the EU adopted a reform of the package. The most important features include:

- Tightening of the EU ETS by increasing the emissions reduction target to 62% of 2005 levels from 43%
- Increasing the annual reduction of allowances from 2.2% to 4.3% for 2024-2027 and 4.4% for 2028-2030 in addition to one-off absolute cap reductions of 90 million and 27 million allowances in 2024 and 2027, respectively
- Coverage of maritime shipping in EU ETS starting 2024 and full phase-out of free allowances in 2026
- Phase-out of free allowances for aviation by 2027
- A new ETS for buildings, road transport and small industries and allocation of revenues to fund Social Climate Fund to support affected parties
- Implementing the carbon border adjustment mechanism (CBAM)

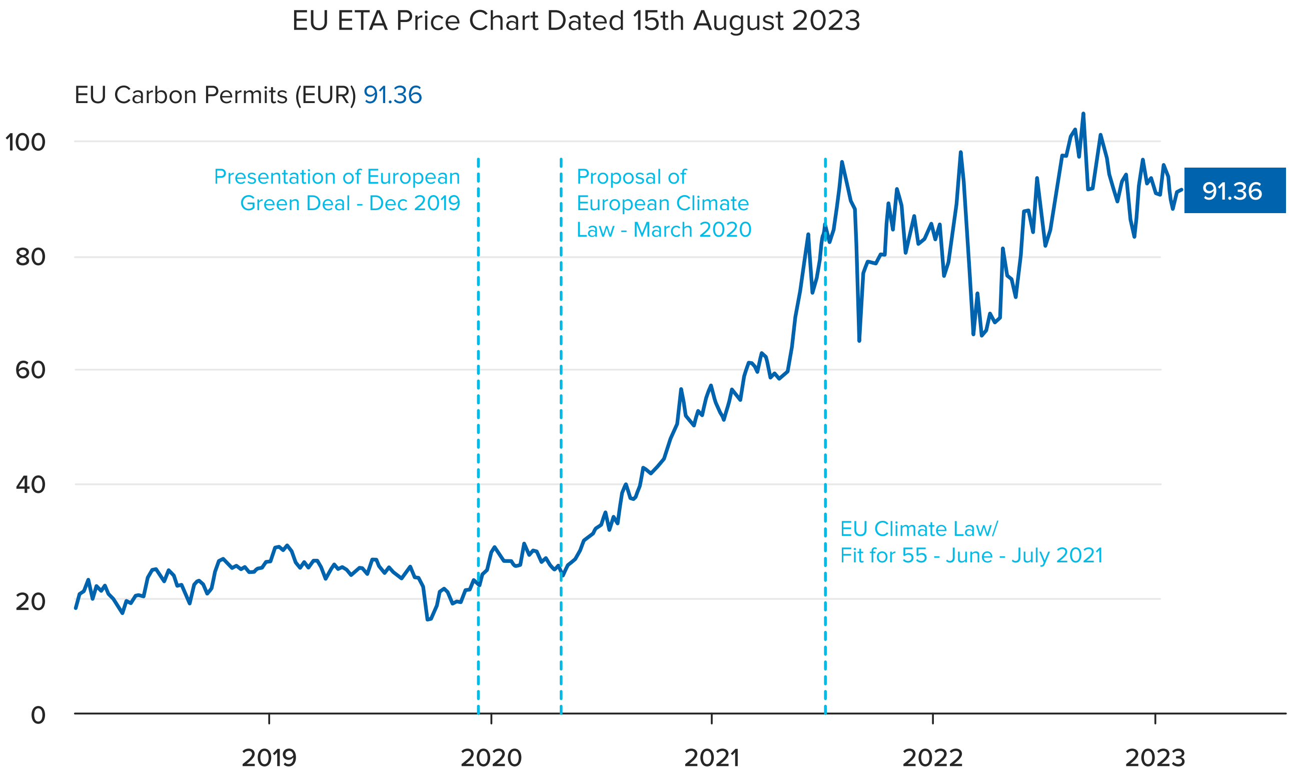


Figure 2: EU ETS price chart dated 15 August 2023. Source: Trading Economics, 2023

The EU Innovation Fund

The EU Innovation Fund is funded by the EU ETS and provides financial support through grants for deploying innovative technologies, including CCS facilities to meet net-zero commitments and the energy transition. The EU Innovation Fund also supports various EU commitments like the Hydrogen Bank, REPowerEU Plan, the Net-Zero Industry Act, and the Green Deal Industrial Plan.

In 2023, the EU increased the size of the ETS allowances from Eur450 million to Eur530 million. At current EU ETS prices, the total size of the EU Innovation Fund for the 2020-2030 period could be Eur40 billion.

Carbon Border Adjustment Mechanism (CBAM)

The EU parliament in April 2023 passed the CBAM to address emissions without hurting its economy. It is effectively a carbon duty on imports from countries without an equivalent carbon tax or price. As the free allowances phase out, CBAM will kick in to protect domestic industry from import competition.

The transitional phase, i.e. the reporting requirement, for importers starts October 2023 and ends January 2024. It will initially apply to carbon-intensive goods like steel and cement and expand to cover 50% of the ETS covered sectors. The permanent phase, i.e. the surrender of CBAM certificates based on the EU ETS price, will start in 2026.

CBAM creates a policy question for the EU's main trading partners: Whether to pay the carbon tax or price to the EU or tax their emissions, with the latter being the likely response.

Country initiatives

In addition to the EU-level policy and regulation, member states develop policies and regulations to reach emission reduction targets. For instance, Denmark and the Netherlands pledged EUR3.6 billion (over 15 years) and EUR2.1 billion in state aid for CCS projects, respectively.

Germany announced the launch of Carbon Contracts for Difference (CCfD), a 15-year subsidy program to increase carbon price visibility. The German government plans to support the program with a budget in line with estimates of around EUR50 billion.

Norway has a carbon tax equivalent of NOK 761 ($71) on per tonne of CO_2 for 2023, and the country introduced a plan to increase the tax to EUR200 ($220) by 2030. Norway is a leader in the CCS with the Longship CCS project.

4.3 Japan

Japan identified hydrogen as part of its climate mitigation goals in 2017 with a Basic Hydrogen Strategy, and in April and in June 2023 the Japanese government revised this plan to accelerate the use of hydrogen as a fuel. The plan targets to increase annual supply by six times to 12 million tonnes by 2040 and earmarks *$107 billion* in funding for hydrogen-related supply chains over the next 15 years.

Japan also introduced its version of an ETS, a 10-year The Basic Plan, in February 2023. The first phase, called the GX League, is on a voluntary basis. No transactions have yet occurred and trading is expected in October 2023. The market is expected to cover 40% of reductions and 680 corporate participants. GX League is expected to transition to a compliance market from 2026-2027, with the power sector added in 2034.

5.0 CASE STUDIES

In this section we analyse how different climate change policies create opportunities for CCS applications along the energy transition value chain.

5.1 Case study 1: Clean hydrogen, ammonia

- Clean hydrogen/ammonia shaping up as a critically important component of energy transition
- Benefits from multiple revenue streams, including 45Q or 45V as production (supply) subsidies
- Carbon pricing in the EU, subsidies in Japan and South Korea on the demand side add to returns
- Demand drivers in the US would accelerate development; potential EPA power plant rule could serve as one
- Clean hydrogen with revenue streams beyond 12th year

The potential market for clean hydrogen and ammonia illustrates how different policy tools that incentivise supply and drive demand for clean energy can be instrumental. The growing global demand for low-carbon energy carriers like hydrogen, ammonia, and methanol as alternatives to LNG and coal for power plants and for bunkering fuel in maritime shipping has the potential to create a substantial market for these products.

Hydrogen and its derivatives, such as ammonia, are energy carriers that can potentially be used in power generation, industry and transportation fuel. While hydrogen is considered a viable clean energy alternative, transportation of it is expensive: The key challenge is to reduce the cost and high capital expenditure needed to build the pipelines, minimise leakage, etc.

If hydrogen is to be transported like LNG with very large gas carriers, it must be cooled to minus 253 degrees Celsius, which is highly energy-intensive. Combining hydrogen with other molecules has the potential to increase the feasibility of transportation. Ammonia has emerged as one of the solutions, as it can be transported at ambient pressure at *minus 50 degrees Celsius* or under 7.5 bar pressure at 20 degrees Celsius.

Demand growing for clean ammonia

Global demand for ammonia as an alternative is fueled by Europe due to the EU ETS regulation and increase in carbon price and by Japan and South Korea, which include the use of low-carbon hydrogen and ammonia in their climate mitigation plans. In Europe, ammonia is sought as an alternative to LNG in power generation, and in Japan and South Korea as an alternative to coal.

The share of maritime shipping accounts for nearly 3% of global emissions. The International Maritime Organization (IMO) member states have *agreed* to major improvements to their initial 2018 targets. The new targets call for net zero by 2050 as opposed to 50% reduction previously and introduce indicative checkpoints by 2030 and 2040.

In 2022, global trade of LNG was *409 million tonnes* and global bunker fuel demand was *135.6 million tonnes*. Replacing only 10% of the current demand for these fuels would require the production of more than *130 Mtpa* of clean ammonia. Replacing current ammonia production (195 million tonnes in 2022; 80% used for fertiliser) with clean ammonia would increase demand further.

An even larger opportunity is the potential as an alternative to natural gas and coal. Japan's largest power generator JERA is *testing ammonia* co-firing for power generation. A consortium including Japan Engine Corporation and NYK has developed ammonia cofiring engines. Other prominent technology providers are also working in similar applications in other countries. Japan and South Korea are already incentivising supply chains for clean ammonia or hydrogen, with Japan earmarking US$107 billion in subsidies, and the introduction of carbon pricing is likely to increase the durability of demand.

Demand in Europe is likely driven by stabilising carbon prices and the phasing out of free allowances for maritime shipping and power generation, with utilities exploring offtake opportunities. Based on this simple analysis, demand for clean ammonia could easily be tens of millions of tonnes per year within a decade.

CCS is one of the critical technologies that make clean ammonia possible. Traditional *ammonia production* without CCS is highly carbon emission-intensive at around 2.4 t CO_2 per tonne of production, nearly twice that of crude oil. More than 90% of the emissions from conventional ammonia production arise from production of *hydrogen* from unabated natural gas, the main feedstock. Therefore, producing clean hydrogen at a low cost is essential for clean ammonia feasibility. CCS enables this.

Clean hydrogen may be produced using electrolysis of water powered by zero-emissions electricity -- a very energy-intensive process itself, reformation or partial oxidation of natural gas with CCS or gasification of coal or biomass with CCS.

The deployment of electrolysis requires a substantial amount of renewable or nuclear electricity capacity along with storage, which constrains where it can be deployed. Production of clean hydrogen using gas and CCS is far less constrained.

Potential in US Gulf Coast

Abundant natural gas resources in the US Gulf Coast, proximity to transportation, and existing or developing CO_2 pipeline and storage sites in nearby locations make it an excellent potential hub for producing and exporting near-zero emissions ammonia using CCS.

The incentives provided in the IRA and the EU ETS carbon price, by providing production-side subsidies or increasing the cost of traditional fuels such as LNG, strengthen the case. As a result, a substantial number of world-class hydrogen and ammonia plants have been announced in the US: If all planned developments go into production, around 35 million tonnes of clean ammonia could be produced by these facilities and 50 million tonnes of CO_2 captured and sequestered.

PROJECT	PRODUCT	LOCATION	CAPACITY*	COMPLETION	TARGET MARKET
CF/Posco	Ammonia	Blue Point LA	1.2	2030	Korea
CF/Lotte/Mitsui	Ammonia	Blue Point LA	1.2	2030	Korea
CF/Exxon/EnLink	Ammonia	Ascension Parish LA	1.2	2028	Export
Linde/OCI	Ammonia	Baumont TX	1.1	2027	Europe
Yara/Enbridge	Ammonia	Corpus Christi TX	1.4	2027	Europe
CHW/MOL/Hafnia/Den	Ammonia	Ascension Parish LA	7.2	2027	Europe
Mitsubishi/Lotte/RWE	Ammonia/ Hydrogen	Corpus Christi, TX	10.0	2030	Asia/Europe
CRC/Brookfield	Ammonia	Northern CA	0.2	2027	California
Air Products	Hydrogen/ Ammonia	Ascension Parish LA	1.4	N/A	Export
Exxon / SK Materials	Hydrogen/ Ammonia	Corpus Christi TX	6.0	N/A	Asia
Copenhagen IP/SFG	Ammonia	St. Charles Parish	5.0	2027	Europe
TOTAL			**~ 35**		

* Million NH3 Tonnes Equivalent

Table 3: Planned clean hydrogen/ammonia projects in the Gulf Coast

Revenue streams for clean ammonia

The following analysis calculates the internal rate of return on investment for a hypothetical clean ammonia production facility exporting to Europe. This analysis requires many simplifying assumptions and must not be considered investment advice.

The 45Q tax credit is effectively a $85 subsidy for each tonne of CO_2 captured and geologically stored for 12 years, the first five years of which are direct pay. The 45V tax credit is provided for producing clean hydrogen at varying rates depending on the lifecycle CO_2 emissions during the production process. It is $1 per kg of hydrogen if the carbon content is between 0.45 kg and 1.5 kg of CO_2 per kg of hydrogen, which is assumed for this analysis.

That said, changing the subsidy to 45Q does not yield to a significant impact in project economics. For hydrogen produced with a lifecycle emissions intensity of less than 0.45 kg of CO_2 per kg of hydrogen, the subsidy triples to $3 per kg of hydrogen.

A clean hydrogen/ammonia producer can claim either the 45Q or the 45V tax credit, but not both.

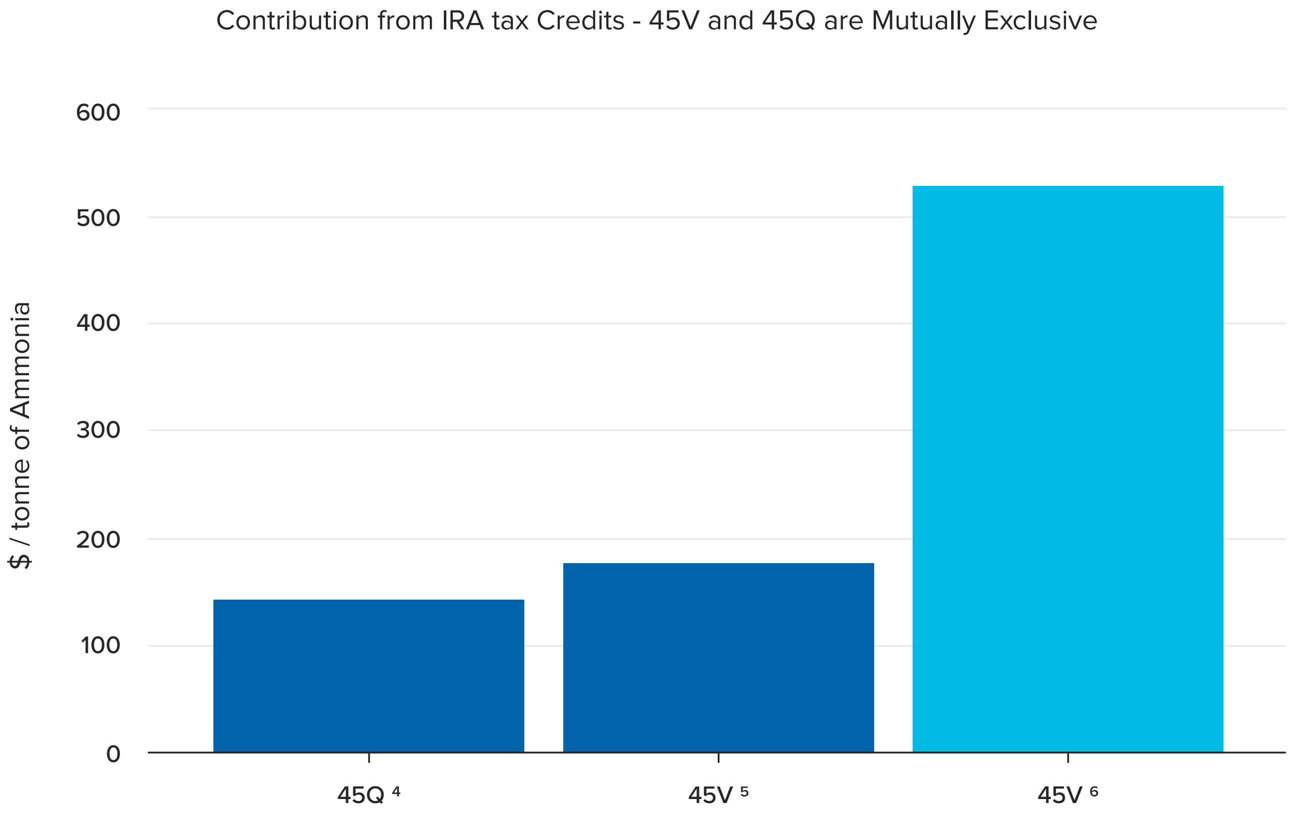


Figure 3: Monetary value of 45Q, 45V tax credits per tonne of ammonia

It is important to note that the exact calculation of 45Q and 45V tax credits will depend on guidance from the US Treasury expected by the end of 2023, especially regarding the definition of low-carbon hydrogen and computation of lifecycle emissions.

The sale price of clean ammonia will depend on a number of factors. For the purposes of this analysis, we have assumed an equivalent price to LNG or bunker on an energy basis and then corrected for CO_2 emissions during utilisation, assuming an EU ETS price of Eur91 per tonne of CO_2 as of 31 July 2023.

As ammonia combustion produces zero CO_2 emissions, this increases the potential price of clean ammonia. The Platts US Gulf Coast CFR Blue Ammonia spot price average for June 2023 is also shown for comparison.

4. Based on 45Q Federal tax credit of $85 per tonne of CO_2 captured and stored. The conversion to ammonia is based on an ammonia-to-captured CO_2 ratio of 1:1.6.
5. Based on 45V Federal tax credit of $1 per kg of hydrogen if CO_2 content per kg of hydrogen is between 0.45 and 1.5 kg.
6. Based on 45V Federal tax credit of $3 per kg of hydrogen if CO_2 content per kg of hydrogen is less than 0.45 kg.

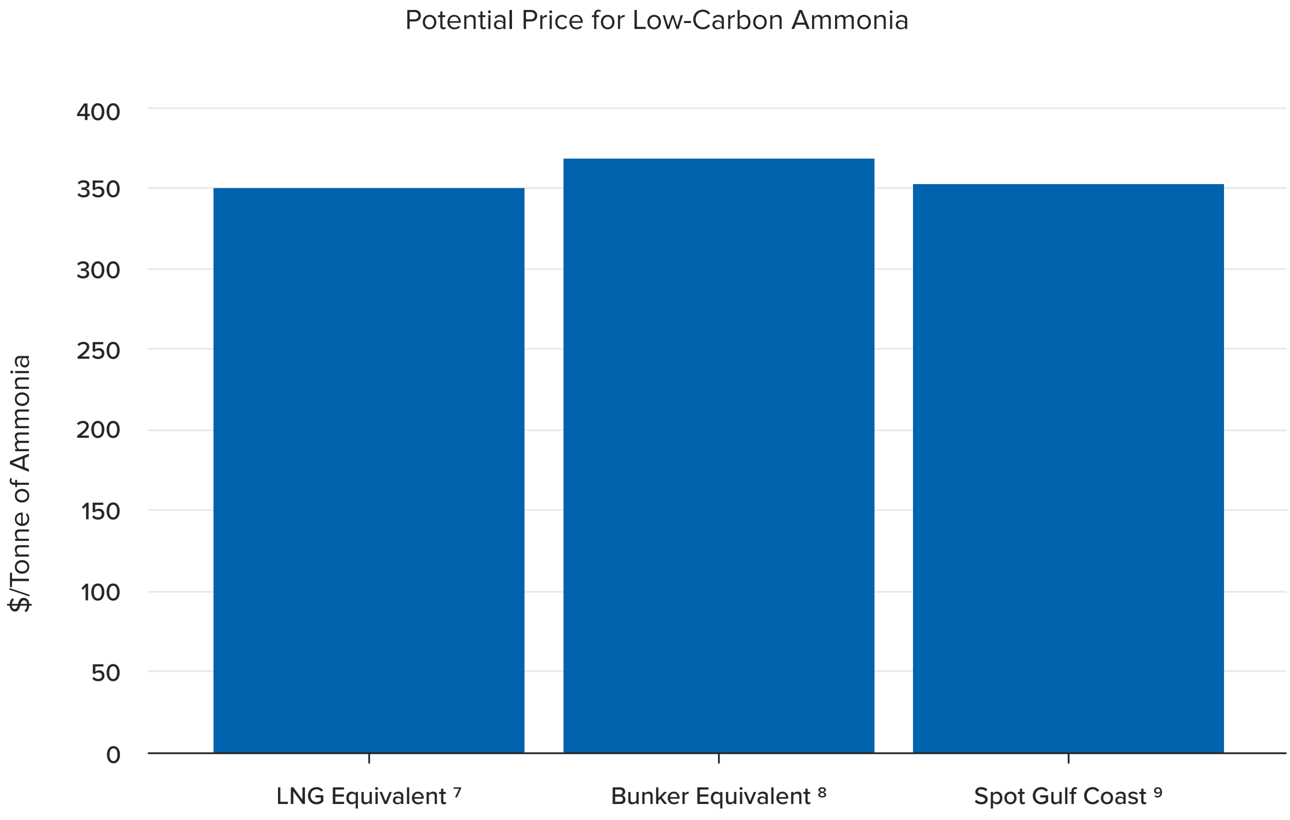


Figure 4: Hypothetical LNG and bunker fuel equivalent price of ammonia

With the above assumptions adding the tax credit and the potential value of ammonia to the utilities and maritime sector, a producer could receive revenue of between $500 with 45Q and $900 with the best case 45V per tonne of ammonia. The steep increase reflects the incentive to achieve lifecycle emissions of less than 0.45 kg of CO_2 per kg of hydrogen produced.

Excluding the best-case 45V scenario, these revenues provide attractive operating margins, with operating expenses estimated to be below $250, including shipping. Our analysis is based on the $1 per kg of hydrogen 45V subsidy the IRA provides.

The following chart provides the Institute's estimate of the breakdown of operating costs based on available literature and engagement with project developers, technology providers, maritime operators, and financial professionals.

7. Based on ammonia energy content of 18.8 MJ/kg, vs. LNG 50.0 MJ/kg, CO_2 emissions of 2.57 kg per tonne of LNG, LNG price of Eur45/MWh (TTF) and, ETS price of Eur91 per tonne of CO_2.
8. Based on ammonia energy content of 18.8 MJ/kg vs. bunker 40.0 MJ/kg, CO_2 emissions of 2.94 kg per tonne of bunker, bunker price of $520 per tonne (Houston) and ETS price of Eur91 per tonne of CO_2.
9. Spot blue ammonia price (Platts – June 2023)

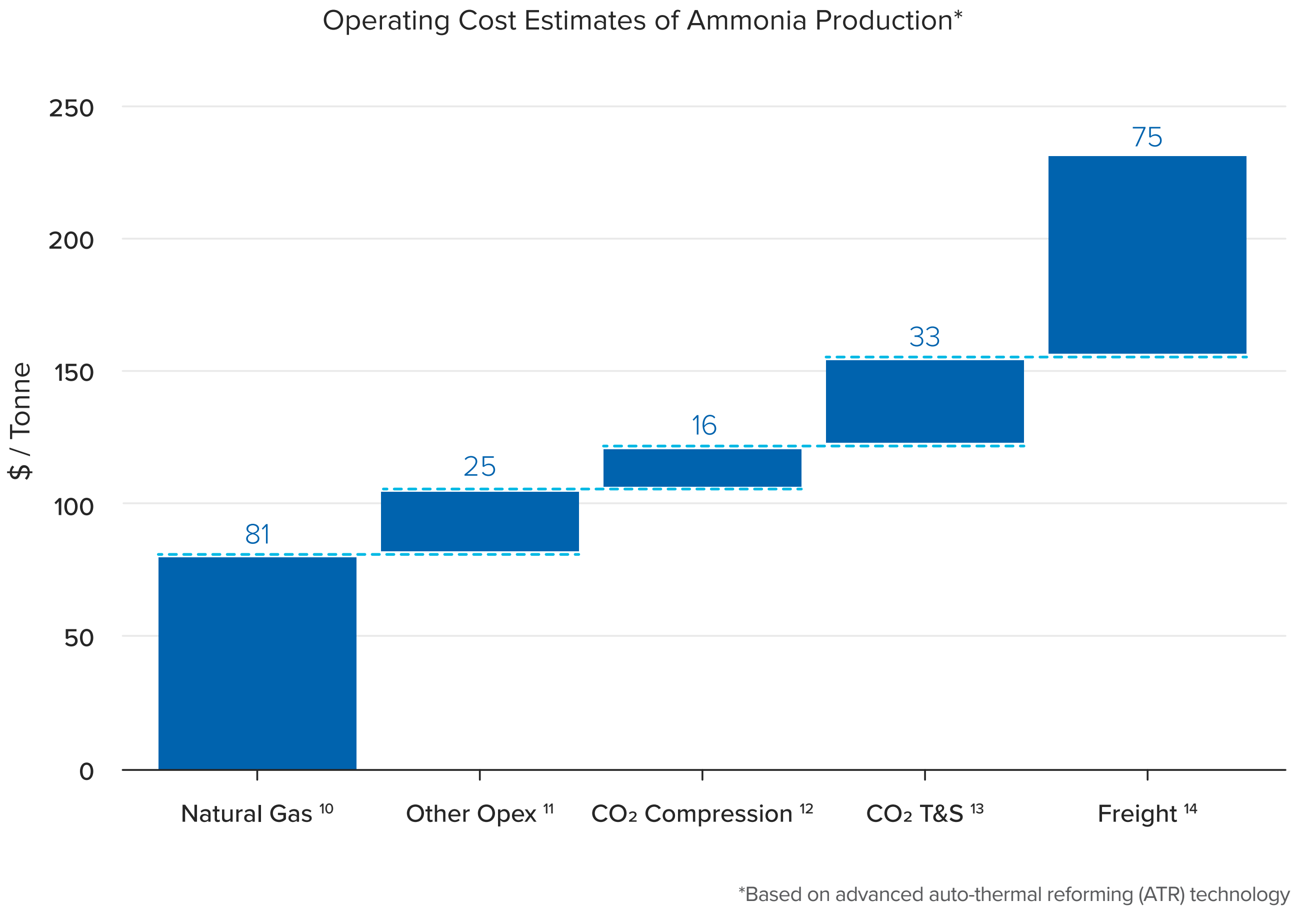


Figure 5: Operating Cost Estimates of Ammonia Production

Based on announcements by companies developing clean ammonia projects, the capital expenditure per tonne of ammonia production capacity is between $1,400 and $2,100.

With these assumptions, the unlevered internal rate of return is estimated to be between 10.2% and 17.4% with a 25-year economic life and 10-year tax credit.

This simple analysis illustrates how policy can incentivise investment in CCS. In this case, a production subsidy in the US combined with a carbon price in Europe and demand support in Asia contribute to sound returns on investment.

At the same time, this analysis illustrates the level of policy support needed to make the energy transition financially feasible. In this case, the combination of a production subsidy equivalent to $105 per tonne of CO_2 captured and sequestered and an EU ETS carbon price of $102 equate to a total carbon price of more than $200. Furthermore, carbon pricing provides a long-term incentive for clean energy beyond the 10- or 12-year lifetime of tax credits.

10. Assuming a natural gas price of $2.70/MMBtu (Henry Hub)
11. Includes maintenance, insurance, general and administrative and other expenses
12. CO_2 compression cost of $9.80 per tonne of CO_2 (opex only)
13. CO_2 transport and storage fee of $20 per tonne CO_2
14. Based on LNG shipping rate of $150,000 per day and 12-day trip as a proxy

5.2 Case study 2: Midwest CCS CO_2 Hubs

- Policy-driven ethanol boom demonstrates role of mandates
- Multiple revenue streams (45Z, 45Q, and LCFS) improve project economics
- Ethanol creates a gateway for CO_2 pipelines to reduce industrial and power emissions
- Potential cost overruns, permitting delays are significant risk factors
- Lack of firm CO_2 volume guarantees by investment-grade emitters add to risks
- Calculation of CI factor in US Treasury guidance will be critical for 45Z
- Financial risk increases with size of pipeline and dependency on time-sensitive 45Z subsidy

In this section we analyse the Midwest CCS hub projects with decarbonising ethanol as their backbone. Leveraging ethanol as a low-cost CCS application the pipeline developers, once trunk lines are built, are aiming to decarbonise the Midwest industrial and power plant sectors. The investment case is to capitalise on ethanol's near-term opportunities and grow as the cost of capture from other industries declines and the cost of emissions increase.

To analyse Midwest CCS pipeline networks, one needs to unpack ethanol economics. The policy-driven ethanol boom in the US (2005-2016) is a striking example of how policy can be instrumental in creating an industry.

Ethanol demand is driven by policies including blend mandates, carbon credits, and subsidies. Blending ethanol with gasoline gained momentum, motivated by energy security concerns, environmental benefits because of lower GHG emissions, and support for the agricultural sector.

The blend mandate gained traction with the 2005 Energy Policy Act and the 2008 Renewable Fuel Standard Program. California LCFS credits and state tax credits, and various farm subsidies provided further support. As a result, *US ethanol production* increased from 3.4 billion gallons in 2005 to 15 billion gallons in 2016 and has stagnated since then in line with gasoline demand. Ethanol consumption as a percentage of gasoline is hovering around 10%.

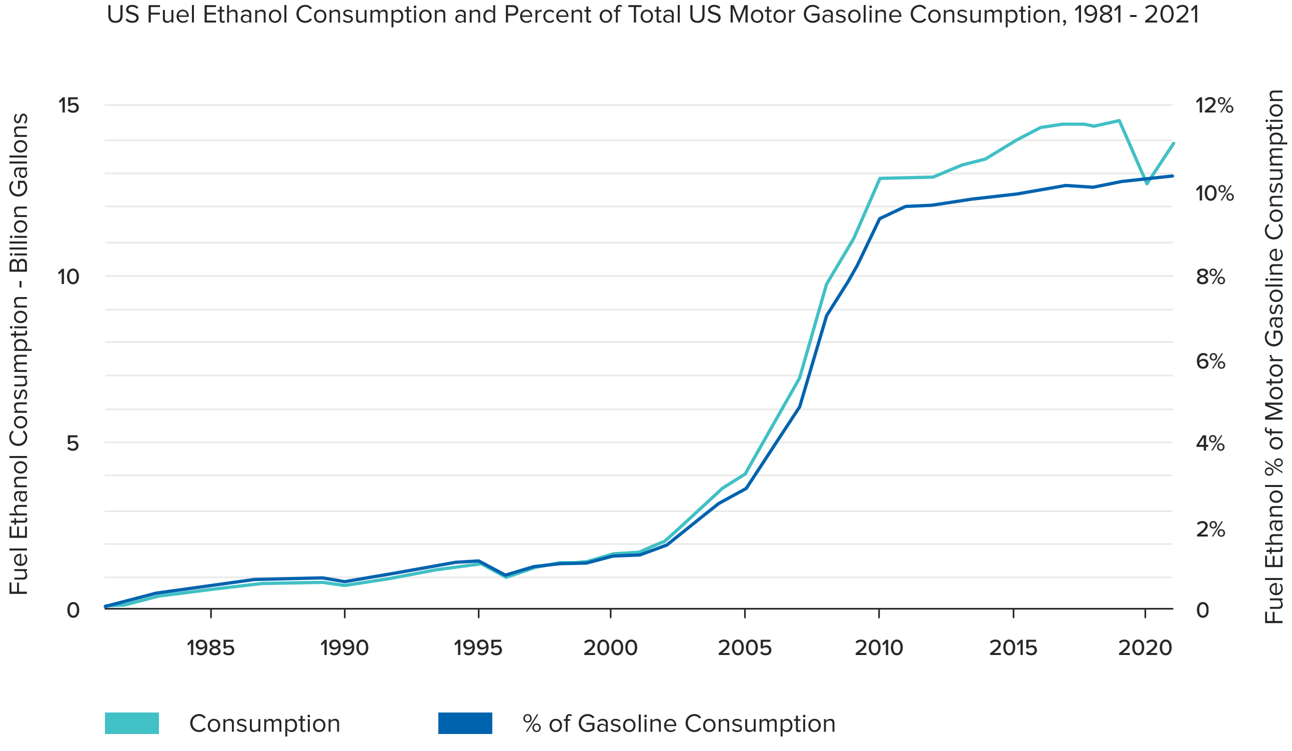
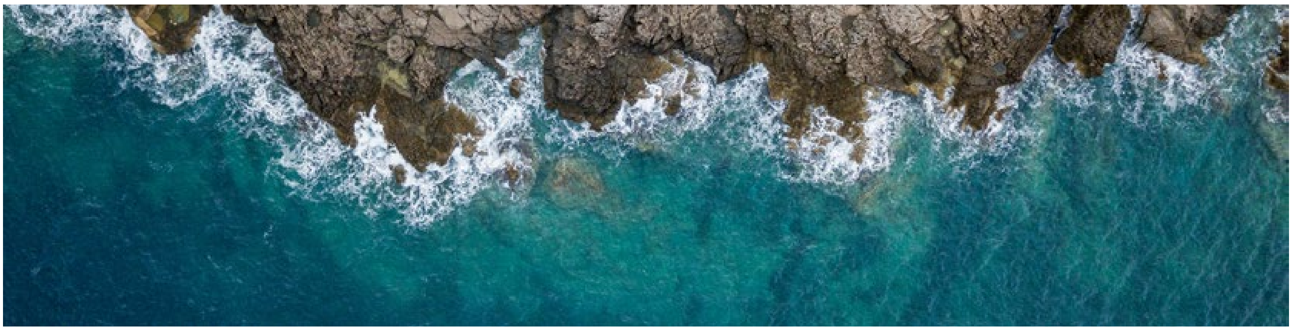


Figure 6: US Fuel Ethanol Consumption and Percent of Total US Motor Gasoline Consumption, 1981 - 2021



Corn in the US and sugarcane in Brazil are the dominant feedstocks for *ethanol production*. In 2022, the US and Brazil *accounted for 55% and 26%* of global ethanol production of 27.7 billion gallons, respectively. Ethanol *operating cash margins* are volatile and hinge on factors including corn yields, substitute prices, weather patterns, and gasoline demand. Since 2018 the average margins have fluctuated between negative 10 cents per gallon to above $1.20 per gallon. As of August 2023 they are more than *60 cents per gallon*, benefiting from favourable corn yields and prices, providing support for CO_2 pipelines. The margin volatility is a risk factor, as there are few investment-grade ethanol producers that can provide firm CO_2 volume guarantees.

Carbon footprint of ethanol

The lifecycle GHG emissions of corn ethanol is 44-52% lower than gasoline, according to the most recent *DOE* report by Argonne National Laboratory (ANL) based on the GREET model in 2021, but still significant *at an average of 54 kg CO_2e/MMbtu* with a wide range from 37 kg to 68 kg CO_2e/MMBtu.

That said, ANL's carbon intensity (CI) calculation is not the only one and differs from California's LCFS calculation; the gap is approximately 12 points. For the revenue streams from the 45Z tax credit, the Treasury guidance will be critical.

The lion's share of the GHG emissions is during biorefining, with an estimated *28 kg* to *35 kg* CO_2e/MMBtu on average, 25 kg to 30 kg of which can be easily captured. Capturing carbon at the biorefinery is one of the lowest-cost applications of CCS due to the high concentration of CO_2 in the process gas stream.

Two existing ethanol projects in the US are the Illinois Industrial CCS Project, capturing 1 million tonnes of CO_2, and the Red Trail Energy project capturing 180,000 tonnes of CO_2 annually. Three new pipeline projects aim to capture a combined 45 Mtpa from dozens of ethanol plants.

Revenue streams for decarbonising ethanol with CCS

The IRA 2022 has provided significant incentives for decarbonising ethanol production. If CCS decreases carbon intensity from 60 kgCO_2e/MMBtu to 30 kgCO_2e/MMBtu by capturing 30 kgCO_2/MMBtu, 45Z translates into $0.02 for each 20-point decrease (50-30) or $0.40 per gallon. The ethanol price as of 31 August was *$2.26 per gallon*.

Expressed in CO_2 terms and assuming an initial CI of 60 kgCO_2e/MMBtu, the 45Z tax credit amounts to $172 per tonne of CO_2 and will be in effect from 2025 to the end of 2027, after which the 45Q tax credit may be claimed.

45Z contribution depends on ethanol's initial CI and has a large range. If we assume a starting point of 70 kgCO_2e/MMBtu, the contribution from 45Z decreases to $0.20 per gallon of ethanol or $86 per tonne of CO_2. Hence, a decrease to 30 CI by CCS application equates 45Z and 45Q in monetary terms.

To make things more complicated, there is no direct pay option for the 45Z tax credit, necessitating a 10% haircut for financial analysis.

The LCFS price was $79 in the last week of August 2023. Considering the prospect of low-carbon ethanol depressing the LCFS market, we assumed $50 for the LCFS price, translating into around $0.105 per gallon of ethanol or $45 per tonne of CO_2 captured. Oregon, Washington State and British Columbia are three other jurisdictions with clean fuel credit programs like California.

Canada introduced *Clean Fuel Regulations (CFR)* that regulates lifecycle GHG emissions of fuels based on the carbon intensity and requires a reduction of 3.5 kg/CO_2e/GJ in 2023 and will increase to 14 kgCO_2e/GJ by 2030. CFR introduces an LCFS like market in which credits will accrue to companies that produce or use clean fuels. This market is also expected to create a *revenue stream* for the clean ethanol producers using CCS.

TAX CREDIT / LCFS		$ PER GALLON OF ETHANOL	EQUIVALENT TO $ PER TONNE OF CO_2
45Z tax credit [15](2025-2027)	Post CCS CI - 25	$0.50	215
	Post CCS CI- 30	$0.40	172
	Post CCS CI - 35	$0.30	129
	Post CCS CI - 40	$0.20	86
45Q [16]	Per tonne of CO_2	$0.18	85
LCFS [17]	At $50	$0.11	45

Table 4: Potential CCS revenues for ethanol (1) ($/tonne CO_2) under the IRA

Below is a visual representation of the potential revenue streams available for the entire ethanol decarbonisation value chain enabled by CCS, assuming a post CCS ethanol CI score of 30:

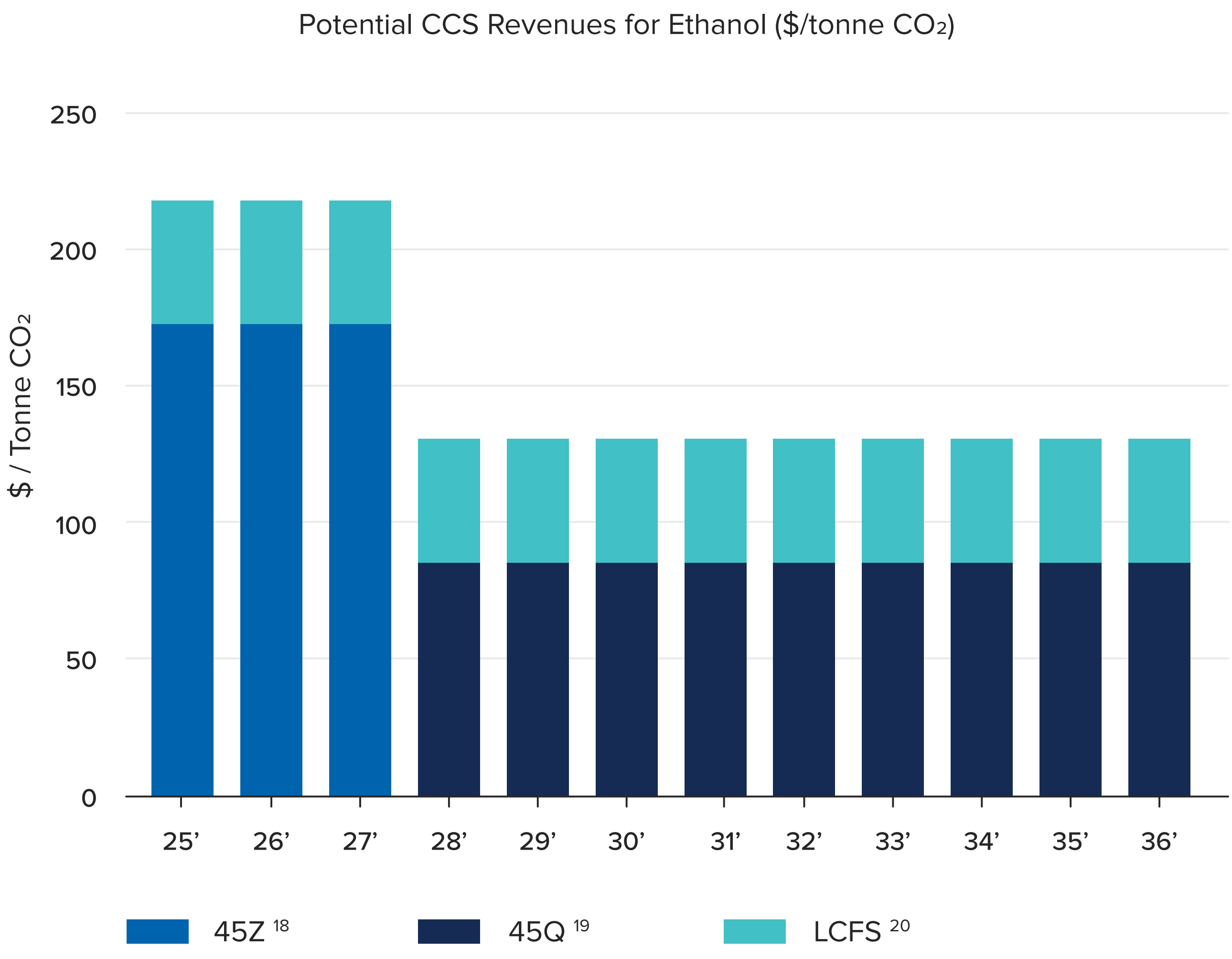


Figure 7: Potential CCS Revenues for Ethanol

15. 45Z and 45V are mutually exclusive – they cannot be stacked
16. 45X for 12 years – or 9 years after 45Z sunsets
17. LCFS price assumed to be $50 – no time limit for LCFS
18. Based on 60 $kgCO_2e$/MMBtu pre-CCS – decreasing to 30 $kgCO_2$/MMBtu for three years (2025-2027)
19. $85 from 45Q for the remaining 9 years
20. Based on an LCFS price of $50 – which continues after tax-credit sunset

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The combined CO_2 transportation and storage capacity of 3 major projects is 45 million tonnes per annum (Mtpa) of CO_2. Assuming 80% pipeline capacity utilisation (equivalent to the current annual ethanol production) a $172 45Z tax credit amounts to an annual $6.6 billion subsidy between 2025 and 2027 and after 2027 an annual $4.1 billion until 2037. In addition, if all ethanol reaches LCFS markets, the revenue for the entire value chain amounts to $2.7 billion per annum.

That said, these assumptions are simplistic. The value of a 45Z credit will hinge on the Treasury guidance on how to calculate the CI score. The strict time limit for the 45Z subsidy creates another risk factor for monetisation if there are time delays. California, Oregon and Washington State, which have LCFS or similar credit markets, *account for 15%* of ethanol consumption as of 2021. Consumption in these states will probably increase but all ethanol is unlikely to benefit from LCFS revenue streams unless the other states launch their own LCFS programs.

45Q, 45Z, and LCFS revenues will be shared along the value chain between farmers, ethanol producers, CCS providers (providing capture, transportation and sequestration services), tax equity partnerships, distributors, and export markets. The division will depend on the negotiating power and the parties' added value. Business models differ from one provider to another, and the contracts with emitters have more detail as to timing, obligations, initial CI score. The Institute's engagement with potential operators and ethanol producers suggests that most federal tax credits will accrue to CCS providers. However, the three projects have different business models and the ratio that accrues to CCS providers differ. The same is true for the LCFS and other revenue streams.

Cost structure of CCS from ethanol production

The institute's engagement with potential operators suggests the operating costs of capturing and geologically storing from ethanol facilities are relatively inexpensive at just below $20 per tonne of CO_2:

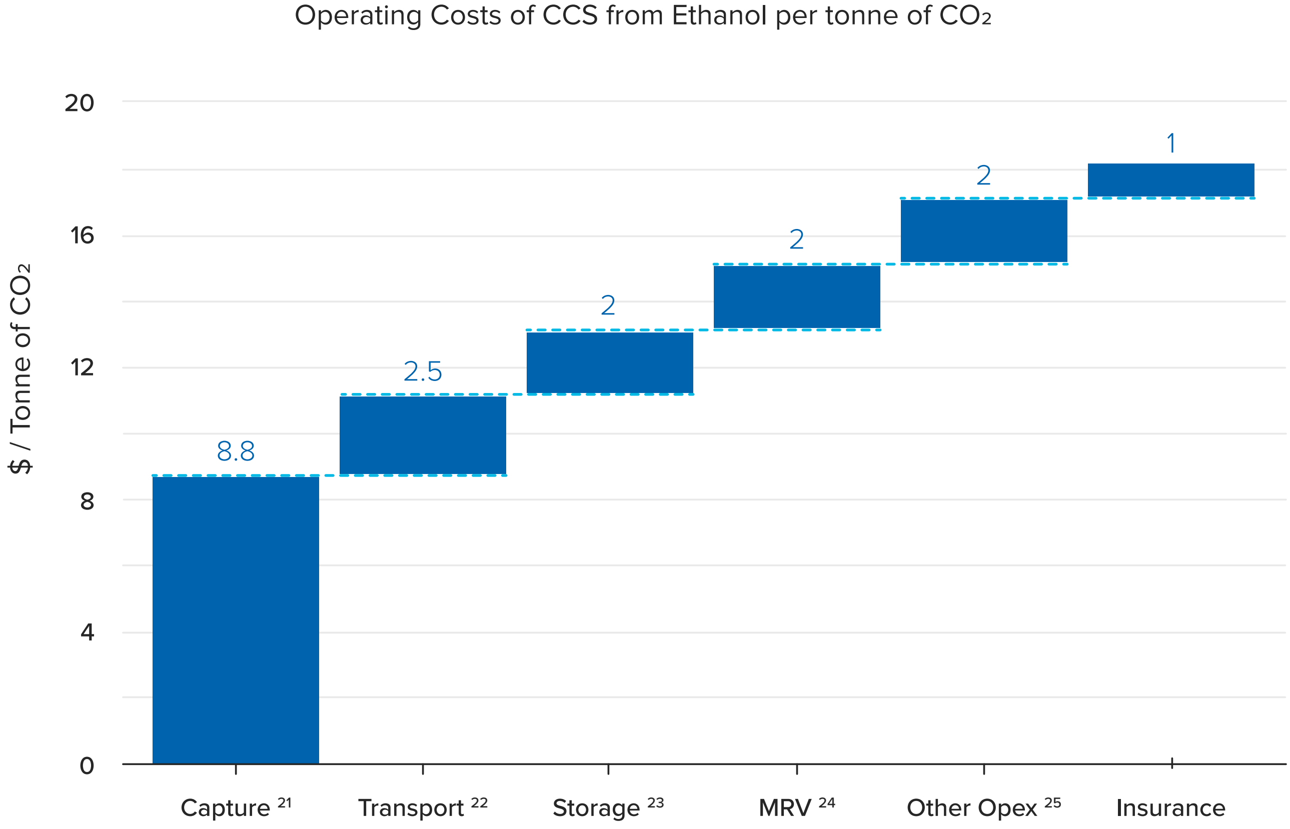


Figure 8: Operating Costs of CCS from Ethanol per tonne of CO_2

The potential revenue streams and operating cash costs per tonne of CO_2 from ethanol production look promising. The attractive cash operating margins have attracted substantial investment from private equity and infrastructure funds to the three main CCS networks that serve the ethanol plants in the region.

OPERATOR	SHAREHOLDERS	INVESTOR TYPE	TOTAL RAISED ($M)
Summit Carbon Solutions (Midwest Carbon Express)	Summit Agricultural Group TPG Rise Tiger Infrastructure Continental SK E&S	Private Equity Private Equity Private Equity Oil and Gas Energy (Korea)	1,350
Navigator CO_2 (Heartland Greenway)	Brookfield Renewables Valero	Private Equity Refinery	NA
Wolf Carbon Solutions (Mt. Simon Hub)	Canada Pension Plan Wolf Midstream	Pension Fund Midstream	NA

Table 5: Shareholders and capitalisation of Midwest CCS networks and hubs

21. 125 kWh/tonne of CO2 Assuming $0.07/kWh
22. 35 kWh/tonne of CO2 at Booster compressor/pump stations
23. Storage fee, state fees, and others
24. Monitoring, verification, and validation
25. Maintenance, labor, G&A

The three projects have pursued different strategies. Summit and Navigator opted for ambitious pipelines: Summit signed offtake agreements with 34 ethanol producers in five Midwest states to connect with a 2,000-mile pipeline to a storage site near Oliver County, North Dakota, owned by Minnkota Power Cooperative. Navigator CO_2's about 1,500-mile Heartland Greenway project connects 31 ethanol producers in five states to two storage sites in Christian and McLean counties, Illinois awaiting Class VI permission from the EPA.

Wolf Carbon Solutions is planning a shorter (285 mile) trunk pipeline in Iowa and Illinois with Archer Daniels Midland Co (ADM) biorefineries and cogeneration facilities in Clinton and Cedar Springs as anchor and sequester at ADM's storage site in Macon, Illinois, and seeking an EPA permit for additional storage sites.

Capital expenditure, permitting remains challenging

While the cash operating margins look attractive on paper, the main challenge is the capital expenditure related to pipeline construction and permitting, and gaining community approval. The following table presents the three projects and their projected capital costs available from publicly available sources.

Based on the Institute's research and engagement with project developers, the major capital items for these projects and the assumptions on which they are based are presented in table 10:

OPERATOR	CO_2 PIPELINE LENGTH (MILES)	PROJECTED CAPEX ($BN)	CAPACITY (MTPA CO_2)	COMPLETION YEAR
Summit Carbon Solutions	1,944	6.0	18	2025
Navigator CO_2	1,352-1,500	4.5	15	2025
Wolf Carbon Solutions	285	1.0	12	2025
TOTAL	**3,750**	**11.5**	**45**	**2025**

Table 9: Carbon capture and storage networks in the Midwest. Sources: SCS Wolf, GCCSI estimates

COST ITEM	UNIT COST ($)	ASSUMPTION
Pipeline cost	150,000 -160,000	Per inch per mile
Compressor cost per facility	30,000,000	1,000 tons per day
Easement payment per mile	122,041	$17,000 - $23,000 /acre land cost - 50" pipeline width
Pump stations (every 200 miles)	25,000,000	Including equipment and installation - to keep at 1400 psi

Table 10

Financial analysis

It is important to note all assumptions provided are based on the Institute's research including engagement with the industry players. There are very few if any examples of CCS projects at this scale, and this analysis cannot be understood in any way as a projection or investment advice.

The cost and time overruns for large infrastructure projects like pipelines are major risk factors to project economics. Summit initially estimated the capital expenditure of its project to be $4.5 billion and the latest estimate is $6 billion because of expansion of the project size and increase in costs. To pay back high capital expenditure, a high capacity utilisation rate is necessary.

As the revenue streams show, Summit's Midwest Carbon Express project depends heavily on the front-loaded 45Z credits. The duration of the 45Z credits in the IRA is three years and the timeline is strict: They start in January 2025 and sunset December 2027. Therefore, any delay in the project execution and permitting could affect the expected return on investment disproportionately and negatively.

Another risk factor is the calculation of the 45Z tax credit; since it starts to kick in at a CI of 50 $kgCO_2e$/MMBtu, the revenue from this subsidy will depend on how fast and how far below this initial CI CCS can take the ethanol producer, hence it hinges on the IRA guidance.

All these moving parts and variables make it challenging to conduct a financial return analysis on ambitious projects with long pipelines, connecting many producers and depending on time constrained 45Z credits. All the risk factors including cost overruns, time overruns and permitting challenges are more pronounced in complex projects and have the potential to derail project economics.

We were able to conduct a return on investment analysis for Wolf Carbon Solutions' Mount Simon hub, which is a pipeline with 285 miles of trunk line and covers two states; Iowa and Illinois. The Wolf pipeline has reduced exposure to time overrun risks because its revenue stream is not relying heavily on the 45Z subsidy. Instead, its business model is largely based on the 45Q carbon capture subsidy, which is not subject to strict time limits. Since the project needs permitting from only two states, the risk of permitting delays is less pronounced.

We assumed that Wolf's Mount Simon will capture 70% of 45Q credits, the balance accruing to the ethanol producers. We did not assume any haircut to 45Q because of the direct pay provisions for the first five years. We assumed that 25% of LCFS credits at a price of $50 will accrue to the CCS operator, which amounts approximately $11 per tonne of CO_2.

The project signed on Archer Daniels Midland Co (ADM), an investment grade agricultural conglomerate, as its anchor CO_2 offtaker and is planning to capture ADM's Columbus and Cedar Springs ethanol plants with an annual capacity of *777 million gallons*, corresponding to more than 2 million tonnes of captured CO_2. Considering there are other producers on the pipeline route, reaching 25% capacity utilisation with relatively short lateral lines seems within reach.

Our basis assumptions for this project include a capital expenditure of $1 billion and a capacity utilisation rate of a conservative 25% or 3 million tonnes of CO_2 captured, transported and sequestered. With operating costs of around $18 per tonne of CO_2, we arrive at a nominal internal rate of return of 14.4% without financial leverage. The sensitivities around cost overruns and time remain limited with a 10% cost overrun and 6-month delay decreasing the IRR to 12.6%.

The Midwest hubs are a good example of building CCS infrastructure starting economically with the low-cost application and extending it to other emitters as cost of emissions go up and the cost of capture decreases.

5.3 Case study 3: CCS in power generation

- 45Q provides attractive returns for coal power plants with CCS, with CO_2 storage on site
- Policy and regulatory support other than 45Q are needed to continue operating the CCS unit beyond 12 years
- Power sector decarbonisation is critical to achieving global climate goals; CCS can be instrumental
- Technology improvements and policy support are key for global CCS deployment

The power sector is one of the largest contributors to global CO_2 emissions, *accounting for 31%* of US and *40% of global* CO_2 emissions in 2022. Efforts underway to electrify heat sources and transportation will further increase electricity demand. If the world is to achieve climate targets, tackling power sector emissions is imperative.

The US has invested heavily in renewable energy to decrease CO_2 emissions over the past two decades. As a result, the *share of renewables* in total US power generation has doubled over the past 12 years to 22% in 2022

However, intermittent energy sources are limited by grid reliability and resilience requirements and the prohibitive cost of grid-scale energy storage for periods exceeding several hours of supply. Other constraints are power transmission, with renewable capacity far from large population centers. Power grids require sufficient dispatchable capacity to meet these requirements. Therefore, natural gas and coal remain a significant portion of the power generation mix.

Even in states like California and Texas, both of which have made strides in installing renewable capacity, power generation from renewable sources *accounts for 49% and 41%* of the total, respectively, with the rest coming from natural gas or coal.

SOURCE	MILLION METRIC TONNES	SHARE OF TOTAL
Coal	847	55%
Natural Gas	661	43%
Petroleum	20	1%
Other	11	<1%

Table 11: CO_2 emissions by the US electric power sector by source in 2022. Source: Monthly Energy Review, April 2023; EIA preliminary data

Coal and gas power generators with CCS are dispatchable with low emissions and can play an important role in meeting emission reduction targets and maintaining modern reliable electricity supply.

Utilities and power generators are incentivised to provide capacity to meet peak demand, maintain electricity transmission, and provide affordable power. Applying CCS to a power plant adds cost that the generator must pass through to the customer, challenging the generator's ability to meet regulations and remain competitive. Business models for previous deployments of CCS at coal-fired power plants relied on the sale of captured CO_2 for nearby enhanced oil recovery, an approach that is dependent on oil prices.

The IRA in the US addressed this barrier to investment. The 45Q tax credit provides a clear and strong economic incentive to capture and permanently store CO_2 from gas and coal-fired power plants. As a result, natural gas and coal-fired power plants have been studying CCS options with the first project announcements closest to suitable geology for sequestration. The Institute's engagement with generators and project managers suggests there are others in the works that are not yet publicly announced.

Project Tundra

One of the first such projects is Project Tundra at Young Power Station in North Dakota. Despite substantial investments in renewable energy in *North Dakota*, which led to wind power generation doubling between 2015 and 2021, coal still accounts for 57% of power generation, with wind at 33% and hydro 5%. The state is a net electricity exporter and sends almost half its generation to the neighbouring states of Minnesota, Montana and South Dakota and to Canada, underlying the importance of coal for the region.

Operated by *Minnkota Power Cooperative* in North Dakota, Young Power Station is supplied by the adjacent lignite mine with a contract extending to 2037 and has two units with a combined generation capacity of 705 MW. Minnkota also invests heavily in wind power, accounting for 34% of capacity and generating 19% of production. Lignite accounts for 67% of production, as the plant is available 93% of the time. North Dakota has ideal geology for CO_2 storage. It is the first state to receive primacy from the EPA in 2018 to issue permits for Underground Injection Control (UIC) Class VI wells to store CO_2. The state is host to five operating Class VI wells.

Minnkota owns two of the largest CO_2 storage Class VI permits in the US, with a capacity of 125 million tonnes, and has a pending application for another one with a *capacity of 100 million tonnes*. It has also agreed to provide storage for Summit's planned Mid-West Carbon Express CCS pipeline planning to service the region's ethanol producers.

Minnkota started to develop Project Tundra in 2018 to retrofit Young 2 with CCS technology to capture 90% of the CO_2 emissions, up to 4 Mtpa. The economic rationale for the project was to sell the captured CO_2 to oil producers for EOR like the Petra Nova project in Texas. The collapse in oil prices in 2020 destroyed the business model for Petra Nova and it has consequently suspended CO_2 capture. Petra Nova, 100% owned by JX Nippon resumed CCS operations recently.

The increase in value of 45Q tax credits by the IRA allowed the project to proceed. The development study cost of Project Tundra, amounting to about $50 million, was financed by Minnkota and grants from the North Dakota Industrial Commission, the federal government, and state regulators. The IRA includes a direct pay option for cooperatives, boosting Project Tundra. Following the Treasury guidance about transferability, Minnkota announced it was seeking a final investment decision in the first quarter of 2024, pending further guidance on tax credits.

Minnkota chose Mitsubishi Heavy Industries (MHI) as the technology partner, which since the early 1990s has developed the Kansai Mitsubishi Carbon Dioxide Recovery Process Advanced (KM CDR Process™), the proprietary *KS-1*™ and the next generation KS-21™ amine solvent for CO_2 removal from combustion gas exhaust streams. This is the same technology utilised by Petra Nova with a capture rate of more than 90%.

MHI will collaborate with Kiewit to construct the CCS facility, and TC Energy will be the commercial partner for the *project*. Project Tundra, which is expected to cost $1.45 billion, has applied for a $350 million grant through the DOE's Carbon Capture Demonstration Projects Program. North Dakota's Clean Sustainable Energy Authority (CSEA) approved a total of $250 million low-cost loan.

Completing a financial analysis of Project Tundra depends on many factors that are unknown including how the project developer, which operates a portfolio of generation assets, defines the scope of the project with respect to costs and revenues, as well as operational and engineering variables. Thus, the Institute constructed a simple engineering model based loosely on Project Tundra and publicly available data to explore the potential returns of CCS retrofit on a coal power plant. Using this model the Institute's high-level analysis suggests attractive returns, even assuming a project lifetime of 12 years, a relatively short period for an infrastructure project.

The operating costs estimated at a total of $37/t$CO_2$ assume that a coal plant with the same original capacity as the Young Power Station is retrofitted with CO_2 capture and then operates at 90% utilisation to maximise electricity generation and sales. Other assumptions include a $0.07 per kwh electricity price, $2.05 per MMBtu coal price and maintenance at 2% of capital expenditure. This results in the capture of 5.1 Mtpa of CO_2 at the targeted capture rate of 90%. The nominal internal rate of return for this hypothetical project is estimated at 11.2%, with the $250 million loan from North Dakota's Clean Sustainable Energy Authority (unlevered 10.2%) and a total capital cost of $1.67 billion scaled up from $1.45 billion announced by Project Tundra to account for the larger capture capacity of this hypothetical example.

For simplicity we assumed no use of waste energy for the CO_2 capture process. In reality, a proportion of the energy required for solvent regeneration could be provided by low-grade heat that currently goes to waste, reducing the operational cost and improving the rate of return to that presented here. Also a capture rate of 95% as in the environmental assessment submitted to the DOE could improve the project economics.

If this plant secured the $350 million grant from the DOE that Minnkota is seeking for Project Tundra, the internal rate of return would improve further. As a regulated entity Minnkota is required to pass on the returns above a certain rate to consumers and invest to meet the power demand of its customers.

It is clear that the $85/t$CO_2$ 45Q with cheap fuel cost incentivises maximising utilisation and electricity production with CCS, and maximising CO_2 captured and stored which also reduces the unit cost of capture. Our analysis suggests that with economic incentives provided by the IRA, applying CCS to a coal-fired power station is an economically feasible approach to supplying low emissions dispatchable power if CO_2 storage is close proximity. The project economics is eroded if the plant does not own its storage and must pay a pipeline operator for transport and storage fees.

Both capital expenditure and operating costs are expected to decrease through learning and standardisation, improving the project economics. The Institute's engagement with technology providers suggests the operating energy requirements for capturing CO_2 are trending in the range of 3.1 GJ per tonne down to 2.1-2.4 GJ per tonne of CO_2.

However, it is unknown if costs will fall quickly enough to enable wide-scale adoption of CCS in power generation where additional transportation costs will be required.

Such projects may need a further impetus to decarbonise through carbon pricing or a mandate to decrease emissions. For example, a regulated utility would find it much easier to utilise the IRA 45Q opportunity to take FID for a CCS project if it was mandated to decarbonise. The proposed EPA rule that introduces a timeline for the gradual elimination of emissions from power generation facilities may support improved economics for CCS projects and accelerate decision making.

Considering coal-fired power plants in China and India provided *58.4%* and *73.1%* of total power generation in 2022, respectively, employing CCS at thermal power stations to reduce emissions can play a critical role in reducing emissions.

To be economically feasible for plant operators, a combination of policies including subsidies, carbon pricing such as the EU ETS, and gradual abatement mandates will be required.

6.0 CONCLUSIONS

The introduction of strong and decisive policy and regulation in the developed world, mainly in the EU and the US, has materially improved the business case for CCS projects. This includes the IRA in 2022 and IIJA in 2021 in the US, changes to the EU ETS with the reform of the Fit for 55 package in the EU, and the inclusion of clean hydrogen in Japan's climate mitigation plans.

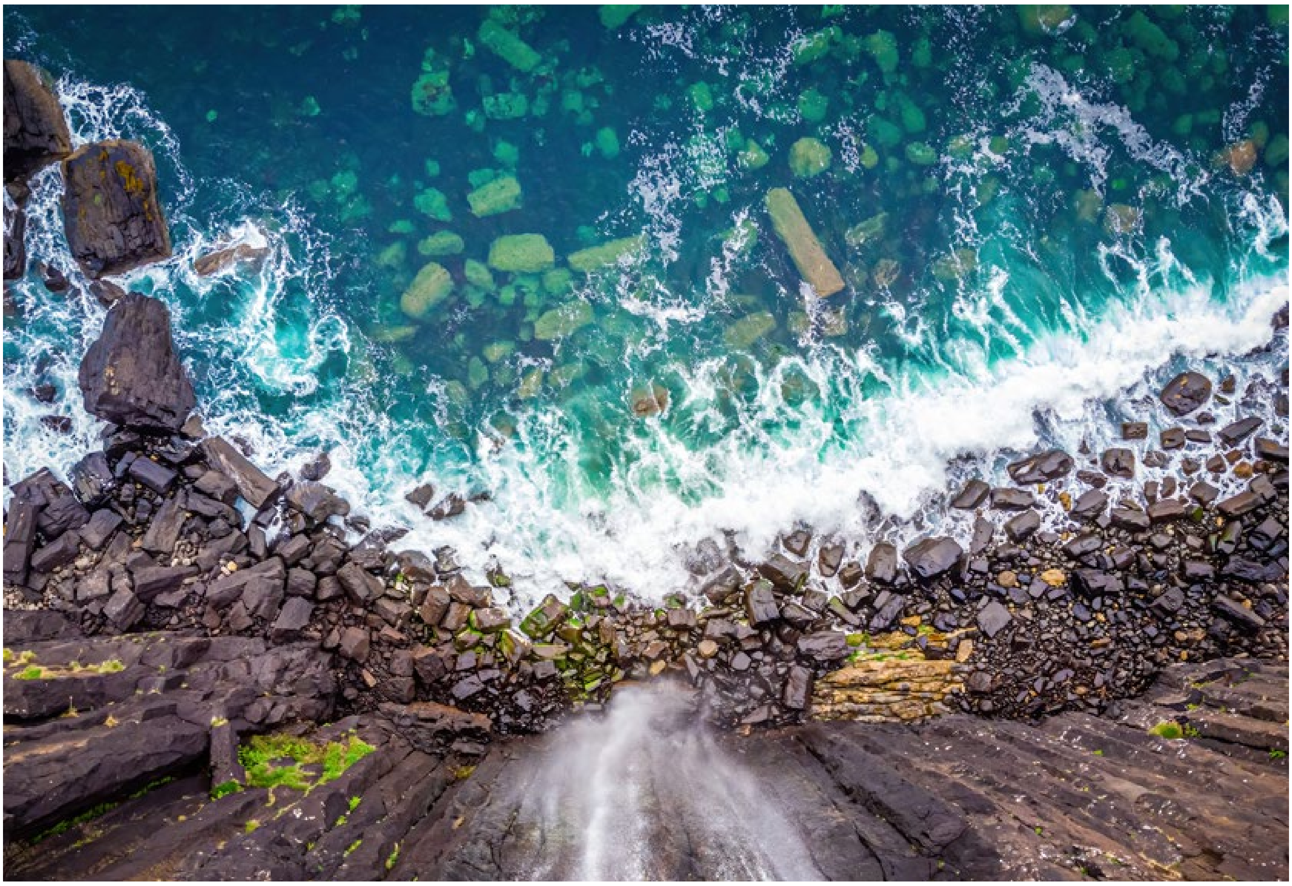
The result has been an exponential increase in the announcement of CCS investments, in the lowest-cost applications. The financial analysis of the case studies in this report provide a financially attractive case for CCS business models, at least in the US context, where the policy action has been most decisive.

The case studies suggest return on invested capital in the mid-teens as a result of combining multiple revenue streams for CCS projects and taking advantage of government grants and low- cost loans. Investors have taken note, with several projects attracting interest from financial institutions, and there is every reason to believe the interest is likely to continue.

These investments present an opportunity for the CCS industry to demonstrate the effectiveness of the technology in reducing GHG emissions, accelerate the learning curve and spur innovation to decrease the production costs.

Demonstrating the effectiveness of CCS applications presents policymakers with the opportunity to supplement existing production subsidies with policies that will ensure long-term incentives such as carbon pricing and mandates for the gradual elimination of emissions that would accelerate the corporate decision-making process. It would also de-risk the CCS value chain and bolster the investment case -- unlocking the capital flows necessary to deploy in scale.

It is not possible to achieve climate goals without participation by developing countries. The policy action in the developed world is expected the pave the way for technological innovation and the introduction of policies globally that would spur investment in CCS technologies.



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