Clearing the Air on Coal CCS

New tax credits make partial CO_2 capture viable, potentially increasing emissions

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AUTHORS

Pat Knight
Jack Smith

Synapse Energy Economics, Inc.

485 Massachusetts Avenue, Suite 3
Cambridge, Massachusetts 02139

617.661.3248 | www.synapse-energy.com

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EXECUTIVE SUMMARY

The *Inflation Reduction Act of 2022* increased the value of tax credits for carbon capture and storage or utilization (CCS) under Section 45Q of the Internal Revenue Code. But considering the historical performance of carbon capture in the power sector, enormous up-front costs, and variability in unit-level economics, the question remains whether investing in carbon capture is worth it from the perspective of electric utilities, their ratepayers, or the climate. While others have examined how incentives might spur carbon capture at industrial and electric generation facilities, this assessment looks at the narrow, and possibly more extreme case, that tax credits may extend the life and increase the emissions of existing coal-fired power units.

Specifically, this analysis investigates the impact of modified 45Q tax credits on the forward-looking economics of generic existing coal-fired units. Under the modified 45Q credit, the level of capture required for a power facility is benchmarked to its historical emissions, which allows generation owners to pursue CCS projects that capture a small fraction of total possible emissions. Therefore, this assessment tests how the tax credits affect coal unit economics under different existing conditions, including levels of operation and different levels of CCS ranging from “partial” CCS (at a minimum of 22.5 percent capture) to “full” CCS (at 90 percent capture). This analysis does not seek to assess the economics of retrofits relative to alternative sources of energy or capacity.

We find that the increased value of the 45Q tax credit may allow existing coal units with low historical capacity factors to add partial carbon capture technology, resulting in minimal emissions reductions or even net emissions increases. This is because the subsidy rate of the 45Q tax credit appears to exceed the cost of capture at existing coal-fired facilities, reducing the operating cost of the facility. As a result, existing coal units with historically low capacity factors (i.e., that have previously been relatively uneconomic to run) may be incentivized to operate far more often and produce more net CO_2, even with partial capture.

The results of this assessment highlight how a generation owner might seek to game the new tax credit policy for the benefit of investors or other incumbent interests at the expense of the environment and ratepayers. New tax credits may appear to justify an enormous upfront capital investment to build carbon capture, which favors incumbent generation interests. Whether capture equipment will ultimately work as intended, however, is uncertain. Even if it does work as intended, the investment may barely reduce, or even increase, net emissions. If the carbon capture system underperforms or the unit runs less than expected, the financial benefits of CCS may not materialize. This creates risk for the utility and ratepayers. Finally, since the 45Q tax credit lasts only 12 years and CCS projects are very expensive to operate, it is likely that any generator outfitted with CCS would cease operation (or cease using CCS equipment) after the 12 years have elapsed.

Ultimately, it is questionable whether CCS technology is in the best interests of the environment and ratepayers. If assessed only against the cost of continuing to operate a coal plant without CCS, the tax credits may render CCS attractive in the short run. However, assessed against other clean energy options, the continued operation of an existing coal-fired facility may not be economically advantageous.

1. CCS IN THE INFLATION REDUCTION ACT OF 2022

The *Inflation Reduction Act of 2022* (IRA) extended and increased the tax credits for carbon capture and storage or utilization (CCS) that were already available under Section 45Q of the Internal Revenue Code. Power units (and any other industrial facility that emits more than 1000 metric tons of CO_2) are eligible for CCS tax credits for 12 years following installation of CCS.

The new tax credits, like those that preceded them, are separated into two tiers based on the end use of the CO_2 (see Table 1).[1] CO_2 bound for enhanced oil recovery (EOR) or other qualified uses has a lower tax credit than CO_2 headed for permanent storage because enhanced oil recovery (or other uses) are expected to provide an auxiliary revenue stream that offsets the lower tax credit.

Table 1. Section 45Q CCS Tax Credits (dollars per metric ton CO_2)

	45Q Tax Credit Pre-IRA	45Q Tax Credit Post-IRA
CCS for Enhanced Oil Recovery or other Qualified Uses	Increasing to 35 nominal dollars by 2026, then inflation-adjusted	Increasing to 60 nominal dollars by 2025, then inflation-adjusted
CCS for Permanent Storage	Increasing to 50 nominal dollars by 2026, then inflation-adjusted	Increasing to 85 nominal dollars by 2025, then inflation-adjusted

Source: Inflation Reduction Act of 2022 Section 13104; Congressional Research Service.

In addition to increasing the value of the tax credit, the IRA adds a condition that to qualify for the new tax credits, a power facility must capture at least 0.1875 million metric tons (MMT) of CO_2. This is a very small quantity of emissions for any single coal unit; a mid-size 600 MW coal unit with a 65 percent capacity factor, for example, will emit an estimated 3.4 MMT of CO_2 each year.

The statute also sets a technology standard that states any CCS unit must have a “capture design capacity of not less than 75 percent of baseline carbon oxide production," where the baseline for an existing unit is the “average annual carbon oxide production” of the three highest emitting years of the 12 years preceding the CCS retrofit.[2] Under the IRA, the baseline is effectively static, meaning that the minimum capture capability requirement is a fixed quantity of CO_2 per year regardless how much additional CO_2 a unit may produce.[3]

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[1] The specific schedule of payment with regard to inflation can be found at https://sgp.fas.org/crs/misc/IF11455.pdf for the pre-IRA tax credits and https://www.congress.gov/117/bills/hr5376/BILLS-117hr5376enr.pdf for the IRA’s tax credits.

[2] The statute states that CCS must be built with a "capture design capacity of not less than 75 percent of baseline carbon oxide production." The baseline for existing units is calculated by looking at the top three years of emissions in the 12 years preceding the CCS installation. For new units, the baseline is equal to 75 percent of the emissions they would produce by operating for one year at a 60 percent capacity factor. For our analysis, which envisions a 2025 start year, this means looking at years 2013–2024 inclusive, and finding the top years of emissions in that set. We also note that new CCS facilities are only eligible to receive the tax credits stipulated in the IRA if they begin construction by January 1, 2033 (see Inflation Reduction Act of 2022. Sec. 13104 (a) (1)).

[3] The IRA requires that the baseline be adjusted only if, after the completion of the CCS unit, the electric generating unit incurs a capital expense that results in the substantial increase or decrease of emissions. This type of trigger is very unlikely to be

The statute's phrasing may imply that a CCS unit must have the *capability* to capture a certain quantity of CO_2 but is not actually *required* to capture that quantity of CO_2 in order to qualify for tax credits. Under this interpretation, this crucial component of the statute has two major implications for CCS installation: first, because baseline emissions are a function of how often a generator operated in the past, the statute allows installation of CCS units that are built to capture only a small fraction of a generating unit's potential to emit (i.e. emissions it may produce in the future). Second, it allows power plant owners to build CCS units that are capable of capturing 75 percent of baseline emissions under a set of operating conditions that the unit may not realize in the future, allowing it to never come close to capturing 75 percent of baseline emissions in reality. The potential for "**partial capture**" creates clear risk of perverse outcomes from an emissions standpoint.

Consider a unit that runs at 30 percent of its maximum capacity in its baseline year. That unit's owner may claim that the unit can qualify for tax credits with a CCS unit that captures only 22.5 percent of the unit's future emissions, because under a specific set of possible operating conditions—namely, if it were to operate with a 100 percent capacity factor—capturing 22.5 percent of emissions would be equal to 75 percent of the CO_2 that had been emitted by the unit in its baseline year. Effectively, the minimum amount of carbon capture capability needed to qualify for tax credits can be much less than 75 percent of a unit's future emissions.[4]

Because tax credits are paid on a per-ton basis, power units will generate tax credits for every megawatt-hour (MWh) of electricity they produce. This means the tax credits effectively act as a payment for producing electricity. The large value of the tax credits is likely to cause qualifying units to run as much as feasible, perhaps as high as a 90 percent capacity factor.[5] Generation units rarely reach a capacity factors of 100 percent because of maintenance and forced outages, meaning that a partial capture unit would never actually capture 75 percent of its baseline emissions. As the capacity factor of a unit increases, the realized capture rate may trend closer toward 75 percent of the historic baseline, but the released emissions will also increase. In some situations, this may cause the unit to see an overall *increase* in released emissions relative to its historic emissions.

Assuming that an incumbent generation owner is inclined to construct CCS, rather than replace the coal unit with tax-credit-eligible clean energy, the coal unit owner has two options—either build CCS at the

incurred by a generation owner, as it also may result in a reset of requirements under the Clean Air Act (called New Source Review). In effect, the baseline is static.

[4] The equation to calculate the minimum capture capability required to qualify for the 45Q tax credits is equal to 75 percent times the baseline capacity factor (e.g., 75 percent x 60 percent = 45 percent of baseline emissions). The realized capture fraction if following the minimum requirements of the 45Q tax credit is equal to 75 percent times the baseline capacity factor divided by the new capacity factor (e.g., 75 percent x (60 percent / 90 percent) = 50 percent of post-retrofit emissions).

[5] This payment per MWh can be substantial. An average coal unit produces about one metric ton of CO_2 per net MWh prior to a CCS retrofit. After a CCS retrofit, however, the CCS equipment will draw energy and steam from the unit, which will decrease its net electrical capacity. This means that it will take more coal to produce each net MWh sold to the grid, so the average CO_2 intensity per net MWh of the coal unit with CCS will increase. Capturing 90 percent of the emissions of a coal unit, therefore, will result in a payment per MWh that approaches $100 in 2021 dollars. This is because 90 percent capture will decrease a unit's net capacity by approximately one-third. Since the tax credit in 2025 is about $78 per metric ton, the tax credit per MWh will be about 130 percent of $78, or about $100.

minimum level needed to qualify for tax credits (i.e. partial capture) or build a larger, more expensive CCS system designed to capture the vast majority of its emissions. Building a larger CCS unit generates far more tax credit revenue (and may get closer to achieving climate outcomes). Building partial capture, while neither tax beneficial nor climate-aligned, may be perceived as advantageous for some owners unless guardrails are in place to prevent such outcomes. This study reviews both possible outcomes.

2. ANALYSIS AND FINDINGS

The goals of our analysis were to: (1) determine whether the minimum level of carbon capture (i.e., partial capture) necessary to qualify for 45Q tax credits can be economic, (2) compare the economics of that minimum level of carbon capture to the economics of maximizing carbon capture, and (3) compare the economics and emissions of both options to a no-capture scenario.

To do so, we developed a cash flow model for generic, existing coal power units that varied the following factors: unit size; the level of the tax credit; CO_2 transport and storage costs; and the unit's baseline capacity factor prior to carbon capture installation. This baseline capacity factor determined the minimum CO_2 capture capability needed to qualify for tax credits. We then modeled the operating costs of the same generic coal unit in three scenarios: zero carbon capture, the minimum level of capture needed for tax credits,[6] and 90 percent capture. In the carbon capture cases, we developed costs for amine-based, post-combustion CCS, and for the purposes of this analysis we assumed that tax credit revenues increase a coal unit's capacity factor to 90 percent due to the substantial decrease in the unit's marginal cost of operation.[7] See the Appendix for a detailed methodology.

2.1. Partial carbon capture can increase net emissions

Power units with low baseline capacity factors have more room to increase their capacity factors after installing carbon capture. As a result, units with low baseline capacity factors have the potential to install carbon capture with the lowest realized capture rates.[8] Although an increasing capacity factor may bring a generating unit closer to capturing 75 percent of its baseline emissions, it will also increase the amount of emissions that are produced and not captured.

Table 2 shows the results of a unit with a 30 percent baseline capacity factor that, with carbon capture, runs at 90 percent. The minimum capture capability needed to qualify for tax credits is only 22.5 percent of the unit's emissions; but even at this low level of capture, the unit appears much more economic. Due to the increase in generation and low capture rate, however, net CO_2 emissions more than double after accounting for CO_2 capture. In this example, the tax credits subsidize increased emissions at a rate of $40 dollars per metric ton CO_2.

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[6] In this scenario, we assume that units equipped with CCS designed with the minimum capture capacity will also operate the CCS unit at its maximum capability, given the size of the incentive created by the tax credits.

[7] See the Appendix for a description of amine-based CCS and the reason for selecting it.
For a real-world unit, the actual increase in capacity factor would depend on bid prices of other generators competing in the energy market. Given the magnitude of the tax credit relative to the marginal operating cost of a typical coal unit, however, we assume that a coal unit with carbon capture will operate as much as possible and use a 90 percent capacity factor to test the implications of this outcome.

[8] See footnote 3.

Table 2. Generic 750 MW existing coal unit with a 30 percent baseline capacity factor

Performance metric over 12-year CCS Crediting Period	Unit	No Capture	Minimum Capture Rate	Maximum Capture Rate
Capture rate	*% CO_2*	0%	22.5%	90%
Capacity factor	*%*	30%	90%	90%
Total net generation	*MWh*	20.8	57.4	43.8
Avg marginal cost of operation	*2021 $/MWh*	$24	$12	($41)
Net present value	*2021 $ Million*	$40	$953	$1,641
Unsubsidized LCOE	*2021 $/MWh*	$53	$54	$112
Subsidized LCOE	*2021 $/MWh*	-	$33	$6
Total released CO_2	*$MMTCO_2$*	22.4	52.0	6.7
Total change in released CO_2	*%*	-	133% increase	70% decrease
Total CCS cost[†]	*2021 $ Million*	-	$969	$2,815
Total 45Q credits allocated	*2021 $ Million*	-	$1,170	$4,681
45Q credits per ton CO_2	*2021 $/metric ton CO_2*	-	($40)	$299

Note: These three scenarios show the same generic, existing, 750 MW coal unit at three levels of CO_2 capture. In the cases with capture, the unit receives the permanent storage tax credit. Baseline CO_2 transport and storage costs are also accounted for, as defined in the Appendix. The levelized cost of energy (LCOE) is determined on a net generation basis, after the auxiliary load requirement of the CCS island and the plant itself.
[†]The total CCS cost includes the capital cost and operation and maintenance cost across the 12-year tax crediting period.
[‡]The negative sign here indicates that 45Q dollars are subsidizing increases in CO_2 emissions rather than decreases.

As in the case shown in Table 2, it is still clearly more economic for units with a low baseline capacity factor to build CCS with the capability to capture the maximum amount of CO_2 possible rather than at the minimum level needed to qualify for tax credits, limiting the likelihood that net emissions increase. Nevertheless, the possibility remains that unit-specific, real-world constraints make a low capture capability and low capture rate more attractive to a utility.

2.2. Partial carbon capture can improve coal unit economics even with a higher baseline capacity factor

Table 3 shows that, even if a coal unit does not have a low baseline capacity factor, operating CCS designed with the minimum carbon capture capability necessary for equipment to qualify for tax credits can still improve unit economics at a generic, existing coal unit. Even with a baseline capacity factor of 60 percent, the average marginal cost of operating the unit drops below zero. This drop pushes the unit lower in the dispatch order determined by the energy market and ensures that it runs more than its baseline—a result consistent with our assumption that the capacity factor will increase substantially.[9]

[9] See footnote 4.

Table 3. Generic 750 MW existing coal unit with a 60 percent baseline capacity factor

Performance metric over 12-year CCS Crediting Period	Unit	No Capture	Minimum Capture Rate	Maximum Capture Rate
Capture rate	*% CO_2*	0%	45%	90%
Capacity factor	*%*	60%	90%	90%
Total net generation	*MWh*	41.6	52.8	43.8
Avg marginal cost of operation	*2021 $/MWh*	$24	($2)	($41)
Net present value	*2021 $ Million*	$525	$1,111	$1,641
Unsubsidized LCOE	*2021 $/MWh*	$38	$72	$112
Subsidized LCOE	*2021 $/MWh*	-	$27	$6
Total released CO_2	*$MMTCO_2$*	44.7	36.9	6.7
Total change in released CO_2	*%*	-	18% decrease	85% decrease
Total CCS cost†	*2021 $ Million*	-	$1,672	$2,815
Total 45Q credits allocated	*2021 $ Million*	-	$2,341	$4,681
45Q credits per ton CO_2	*2021 $/metric ton CO_2*	-	$299	$123

Note: These three scenarios show the same generic, existing, 750 MW coal unit at three levels of CO_2 capture. In the cases with capture, the unit receives the permanent storage tax credit. Baseline CO_2 transport and storage costs are also accounted for, as defined in the Appendix. The levelized cost of energy (LCOE) is determined on a net generation basis, after the auxiliary load requirement of the CCS island and the plant itself.
†The total CCS cost includes the capital cost and operation and maintenance cost across the 12-year tax crediting period.

The unit's net present value, assessed over the 12-year lifetime of the 45Q tax credit, also increases markedly and the levelized cost of energy (LCOE) falls. These metrics become even more favorable at a 90 percent CO_2 capture rate. Since CCS with a lower capture rate is economic, however, it is possible that such CCS systems will be built in some situations.

In this example, both levels of capture reduce net CO_2 emissions relative to the same unit without carbon capture. Notably, because we assumed the scenarios with carbon capture run more than their baseline, the emissions reductions they achieve are lower than their capture rate—for example, 45 percent CO_2 capture yields only an 18 percent reduction in overall CO_2 emissions.

In this example, the total 45Q tax credit dollars allocated to the coal plant ranges from $2.3 billion and $4.7 billion in 2021 dollars over the 12-year duration of the 45Q tax credit. On a dollars-per-ton basis, this means the unit achieved CO_2 reductions at a cost of between $299 and $123 tax dollars per metric ton.

3. DISCUSSION

Relative to continuing operation of existing coal units, the IRA's new 45Q tax credits may make CCS economic in the power sector, including at a low capture rate. Nevertheless, tax-credit-driven CCS is expensive in both absolute terms and on a cost-per-ton basis. It also carries with it substantial risks, including a net increase in emissions in some scenarios. The decision to retrofit a coal unit with carbon capture must also be assessed against the opportunity cost to replace coal-fired generation with potentially lower-cost clean energy options. The question for utilities and regulatory commissions is how to think about this expense in light of these risks and from an opportunity cost standpoint.

3.1. High upfront costs, uncertain benefits over time

Building CCS infrastructure locks in large costs even if countervailing financial benefits do not materialize. Installing CCS requires financial commitment up front, while tax credits are paid over time as tons of CO_2 are actually captured and successfully sequestered. Historical experience suggests that CCS equipment is difficult to maintain, that it is prone to underperformance, and that capital costs can balloon beyond initial expectations. Further, since tax credits only last 12 years and are essential to the economics of a power unit with CCS, it is unlikely that any unit will continue to operate CCS equipment after the tax-crediting period expires.

Of the four commercial power unit CCS projects undertaken in North America, three have failed entirely and one has a track record of mechanical failure. Kemper County's Ratcliffe unit, often just called "Kemper," was designed in 2008 to capture 65 percent of the unit's CO_2 at an initial estimated cost of $2.4 billion, or about $4,100 per kW.[10] Construction costs ballooned to over $7.5 billion in 2017 dollars (translating into a per-kW cost of about $13,000 per kW), and the unit's CCS component was ultimately dropped. Today, the 769 MW unit burns natural gas.[11]

Likewise, Edwardsport, a Texas-based project proposed in 2006, was hailed as a 618-MW "technological marvel" that would usher in the era of "clean coal."[12] Ten years later, the original $1.6 billion cost overran to $3.5 billion (in 2017 dollars), and the carbon capture component was abandoned.[13]

The world's first commercial-scale post-combustion coal-fired CCS project was built in 2014 at the SaskPower Boundary Dam facility, an 813-MW unit in Canada. The facility was designed for 90 percent CO_2 capture using Shell's "Cansolv CO_2" amine solvent blend and was expected to capture and

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[10] "Petra Nova is one of two carbon capture and sequestration power units in the world." *EIA Today In Energy*. October 31, 2017. Available at https://www.eia.gov/todayinenergy/detail.php?id=33552.

[11] Ibid.
"The Kemper project just collapsed. What it signifies for CCS." *EnergyWire E&E News*. October 26, 2021. Available at https://www.eenews.net/articles/the-kemper-project-just-collapsed-what-it-signifies-for-ccs/.

[12] "Can Duke's Edwardsport turn tide for clean coal post-Kemper?" *EnergyWire E&E News*. July 20, 2017. Available at https://www.eenews.net/articles/can-dukes-edwardsport-turn-tide-for-clean-coal-post-kemper/.

[13] Ibid.

permanently store approximately 1 MMT CO_2 per year. Equipment failures have affected reliability, however, preventing optimal performance. It has only occasionally reached its daily carbon capture goal of 3,200 metric tons and as of 2021, had never done so over an extended period of time.[14]

A second post-combustion facility, Texas-based Petra Nova was designed to be the largest commercial-scale post-combustion coal-fired CO_2 capture project in the world. Supplied by Mitsubishi Heavy Industries America, Inc., Petra Nova's CO_2 capture system began commercial operation in January 2017 on time and on schedule.[15] The system was added to Unit 8 (654 MW) at the existing W.A. Parish unit and was designed to capture CO_2 from a 240-MW flue gas slipstream.[16] Petra Nova ceased carbon capture in 2020 when the COVID-19 pandemic upset the constellation of financial factors keeping it afloat.[17] When Petra Nova stopped capturing CO_2, Boundary Dam became the only operating power unit with carbon capture in the world.[18]

3.2. CCS exacerbates the traditional risks of fossil generation

Even if carbon capture itself appears profitable on paper, it does not alleviate many of the financial risks that fossil-fired power units, particularly coal, currently face. Instead, it may exacerbate them by incentivizing a unit to run more. Future regulations could stack additional non-CO_2 environmental compliance costs on coal units, which still emit a host of well-regulated pollutants regardless of carbon capture. These costs risk turning a large CCS investment into a stranded asset if additional environmental retrofits render the unit uneconomic.

Perhaps the biggest unknown is the likelihood of a zero-emissions standard, which would be necessary for the power sector to comply with President Biden's executive order to achieve net zero power sector emissions by 2035, or similar standards promulgated at the state level.[19] Even if fossil units capture the

[14] Schlissel, David. *Boundary Dam 3 Coal Unit Achieves Goal of Capturing 4 Million Metric Tons of CO2 But Reaches the Goal Two Years Late*. Institute for Energy Economics and Financial Analysis. April, 2022. Available at https://ieefa.org/wp-content/uploads/2021/04/Boundary-Dam-3-Coal-Unit-Achieves-CO2-Capture-Goal-Two-Years-Late_April-2021.pdf.

[15] Petra Nova - W.A. Parish Project. Office of Fossil Energy and Carbon Management, U.S. Department of Energy. Accessed September 2022. Available at https://www.energy.gov/fecm/petra-nova-wa-parish-project.

[16] Ibid. and CO_2 Capture Projects: Best Practices and Insights for Technical Due Diligence in Support of Lenders and Investors. June 2021. Available at https://sargentlundy.com/wp-content/uploads/2021/06/CO2CaptureProjects_WhitePaper2_SargentLundy.pdf.

[17] These factors included "risk tolerant financing" from Japan, grant money from the US Department of Energy, and enhanced revenues from a co-owned oil field, where captured CO_2 was pumped underground to boost oil production through a process known as enhanced oil recovery. The economic turmoil of the pandemic, particularly plunging oil prices, rendered Petra Nova's carbon capture uneconomic. For more, see Jenkins, Jesse. *Financing Mega-Scale Energy Projects: A Case Study of the Petra Nova Carbon Capture Project*. Paulson Institute. October 2015. Available at http://www.paulsoninstitute.org/wp-content/uploads/2015/10/CS-Petra-Nova-EN.pdf.

[18] "CCS 'red flag?' World's sole coal project hits snag." *EnergyWire E&E News*. January 10, 2022. Available at https://www.eenews.net/articles/ccs-red-flag-worlds-sole-coal-project-hits-snag/.

[19] FACT SHEET: President Biden Sets 2030 Greenhouse Gas Pollution Reduction Target Aimed at Creating Good-Paying Union Jobs and Securing U.S. Leadership on Clean Energy Technologies. White House Briefing Room. April 22, 2021. Available at https://www.whitehouse.gov/briefing-room/statements-releases/2021/04/22/fact-sheet-president-biden-sets-2030-greenhouse-gas-pollution-reduction-target-aimed-at-creating-good-paying-union-jobs-and-securing-u-s-leadership-on-clean-

majority of their CO_2, complying with a zero-carbon standard by paying for direct air capture or through other means may add large costs.

With CCS, fossil units would also remain exposed to fuel price volatility. In fact, that exposure would increase as units that install CCS are likely to operate more than before. Likewise, higher capacity factors can be expected to increase forced outage rates as already aging machines run more often. Extending the lifespan of older units because CCS continues to make them profitable increases the risk of breakdown, repair costs, and expensive outages. We did not assess these additional costs in our analysis.

3.3. The opportunity cost of CCS

Even if CCS is profitable, it is not necessarily the most cost-effective generation resource. Without careful analysis through utility-specific capacity expansion modeling, it's unclear whether CCS fits into a least-cost generation portfolio. What is clear is that for the cost of building CCS, large amounts of actual zero emissions resources can also be built.

Following the *Inflation Reduction Act of 2022*, non-emitting resources gained extended and enhanced tax credits alongside CCS. Depending on project specifics, these resources can receive production or investment tax credits on the order of 30 percent to 50 percent. It is impossible to determine which is more worthy of investment without a specific comparison of a utility's fossil-fired generation and available replacement resources.

3.4. Costs and other constraints

This study focused on the costs and unit-level operational impacts that amine-based CCS technology has on generic coal units. Amine-based carbon capture systems are the only commercially available and demonstrated carbon capture technology in the power sector, but the technology presents several unit-specific and site-specific drawbacks that this analysis could not fully address. These factors could make carbon capture physically or financially untenable.

The first drawback is the physical space taken up by CCS equipment, commonly referred to as the "CCS island." As a general rule, the CCS island tends to be about the same size as the coal units it serves. This is the case at Boundary Dam, the only functioning CCS project in the power sector, and at Petra Nova, the now-closed Texas demonstration CCS project described above.[20] CCS systems take up so much space

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energy-technologies/. More than 20 states have also set 100 percent clean energy goals. See https://www.cesa.org/projects/100-clean-energy-collaborative/guide/table-of-100-clean-energy-states/.

[20] Giannaris et al. *SaskPower's Boundary Dam Unit 3 Carbon Capture Facility - The Journey to Achieving Reliability.* 15th International Conference on Greenhouse Gas Control Technologies, GHGT-15 15th - 18th March 2021 Abu Dhabi, UAE. Page 2. Available at https://ccsknowledge.com/pub/Publications/PAPER_GHGT15_SaskPowers_BD3_Journey_Achieving_Reliability_Mar2021.pdf
W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project. Petra Nova Holdings LLC. March 31, 2020. Pages 13 and 14. Available at https://www.osti.gov/servlets/purl/1608572

that the National Renewable Energy Laboratory (NREL), in its 2022 *100% Clean Electricity by 2035* analysis assumed that no existing natural gas units in the United States will build CCS due to physical space limitations.[21] Coal units are generally in less densely populated areas than gas units but still may face space constraints.

An important component of physical space requirements is the cooling capacity required by CCS retrofits, which can create considerable problems for coal units. At Petra Nova, “site constraints” were so severe that the area set aside for the CCS island was not large enough for the cooling tower, water treatment equipment, and other balance-of-unit operations, requiring a secondary island elsewhere on the property.[22] As Sargent and Lundy notes in its pre-feasibility study for retrofitting the San Juan coal plant in New Mexico, the cooling water demand for the prospective CO_2 capture system was “expected to be similar to the circulating water rate” of Units 2 (369 MW) and 3 (555 MW). At the time of the study, Units 2 and 3 were conveniently slated to retire, so the existing cooling towers looked like they could be repurposed. Absent this serendipity, additional water-cooling capacity could add cost by necessitating substantial additional space and, depending on the cooling technology, water consumption.

Proximity to CO_2 pipeline infrastructure is another limitation. Today’s CO_2 pipelines span a collective 5,300 miles, putting only a portion of U.S. coal-fired power units within reach.[23] At an estimated development cost of $3 million per mile, CO_2 pipeline costs may significantly reduce the economic viability of CCS systems.

Last, amine systems are extremely sensitive to the presence of sulfur dioxide (SO_2) and sulfur trioxide (SO_3) in flue gas streams, which may necessitate additional investment in pollution control equipment to make CCS economic. SO_2 and SO_3, two combustion byproducts common in coal unit flue gas, react with the amine solvent alongside CO_2, increasing the energy needed to regenerate it and decreasing the efficiency of the CO_2 capture system. This increase in required energy and decrease in efficiency may, in some circumstances, make an amine system prohibitively expensive to run.

While many coal units already have flue-gas desulphurization (FGD) systems designed to limit SO_2 and SO_3 emissions, not all units have installed more effective (and expensive) wet FGDs. Even wet FGDs are not always capable of delivering flue gas with concentrations of SO_2 low enough for efficient CO_2 capture, necessitating additional investments to prepare flue gas for amine-based CO_2 capture.[24] One

[21] *100% Clean Electricity by 2035.* National Renewable Energy Laboratory. 2022. Available at https://www.nrel.gov/analysis/100-percent-clean-electricity-by-2035-study.html

[22] See Footnote 7.

[23] *Annual Report Mileage for Hazardous Liquid or Carbon Dioxide Systems*. Pipeline and Hazardous Materials Safety Administration, U.S. Department of Transportation. September 1, 2022. Available at https://www.phmsa.dot.gov/data-and-statistics/pipeline/annual-report-mileage-hazardous-liquid-or-carbon-dioxide-systems. We note that this 5,300-mile estimate includes both pipelines for CO_2 and pipelines for “other” gases and liquids, as defined by the Pipeline and Hazardous Materials Safety Administration.

[24] This was the case at San Juan Power Station in New Mexico. For more, see *Enchant Energy San Juan Generating Station – Units 1 & 4 CO2 Capture Pre-Feasibility Study*. Sargent and Lundy. July 8, 2019. Available at https://enchantenergy.com/wp-content/uploads/2019/07/Enchant-Energy_SJGS-CO2-Pre-feasibility-Study_FINAL-Rev-0-7-8.pdf.

example of such an investment is integrating a pre-scrubber into the quencher, which removes additional SO_2 and SO_3 by running flue gas through a caustic solution before it enters the absorber. This is technically possible but adds cost and additional water management challenges.

4. Conclusion

Considering the uncertainties in cost, the range of possible emissions outcomes, and the cost differential relative to wind and solar, utilities and regulatory commissions would be wise to closely examine proposed CCS projects for prudence. Paying close attention to a proposed unit's baseline capacity factor, projected capacity factor, and CO_2 capture rate can reveal the risk embedded in the economics of CCS. To avoid unforeseen cost overruns, large uncertainties such as available water-cooling capacity and cost and CO_2 transport and storage costs also merit close examination.

Overall, if a utility decides to shoulder the uncertainty of CCS in search of the financial benefits, we recommend that shareholders—not ratepayers—bear the risk of cost overruns, schedule delays, and failures to perform. Unless customers are guaranteed to receive high-probability financial benefits, they should be protected from uncertain and expensive capital projects.

5. APPENDIX

5.1. Sources for CCS costs

Synapse sourced generic unit operating parameters and CCS capital costs, fixed costs, and variable costs from a Sargent and Lundy report written on behalf of the U.S. Energy Information Administration.[25] The Sargent and Lundy report provides costs associated with CCS installations featuring capture rates of 0 percent, 30 percent, and 90 percent for coal. We linearly interpolated to develop a full cost range from 0 percent capture to 90 percent capture. Table 4 contains the original, un-interpolated datapoints (adjusted to 2021 dollars). We sourced low ($5 dollars per metric ton CO_2), baseline ($15 dollars per metric ton CO_2), and high ($60 dollars per metric ton) CO_2 transport and storage cost sensitivities from the National Renewable Energy Laboratory.[26] For this analysis, we assumed that the cost to transport and store CO_2 was fully borne by the power unit under examination.[27]

Table 4. Generic unit costs with and without CCS

Fuel Type	Unit Parameters	Unit	CO_2 Capture Rate		
			0%	*30%*	*90%*
Coal	Gross Capacity	*MW*	735	735	735
Coal	Net Capacity	*MW*	647	578	453
Coal	Net Capacity penalty (decrease)	*%*	12%	21%	38%
Coal	Non-CCS capital cost	*2021 $/kW (gross)*	$3,431	$3,431	$3,431
Coal	Non-CCS sustaining capital cost (20-30 yr coal plant, w/ FGD)	*2021 $/kw-year*	$27.9	$27.9	$27.9
Coal	CCS capital cost	*2021 $/kW (gross)*	$0	$557	$1,040
Coal	Non-CCS VOM	*2021 $/MWh*	$5	$5	$5
Coal	CCS VOM	*2021 $/MWh*	$0	$2	$3

[25] *Capital Cost and Performance Characteristic Estimates for Utility Scale Electric Power Generating Technologies*. Written by Sargent and Lundy on behalf of the U.S. Energy Information Administration. February 2020. Available at https://www.eia.gov/analysis/studies/powerunits/capitalcost/pdf/capital_cost_AEO2020.pdf.

For non-CCS sustaining capital costs, see *Generating Unit Annual Capital and Life Extension Costs Analysis.* Written by Sargent and Lundy on behalf of the U.S. Energy Information Administration. December 2019. Available at https://www.eia.gov/analysis/studies/powerplants/generationcost/pdf/full_report.pdf

[26] Denholm, Paul, Patrick Brown, Wesley Cole, et al. 2022. *Examining Supply-Side Options to Achieve 100% Clean Electricity by 2035*. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A40-81644. https://www.nrel.gov/docs/fy22osti/81644.pdf. We also considered per-ton costs developed by Schmeltz et al., but because these fell within the range of NREL's values, we use NRELs in our analysis. For more, see Schmelz WJ, Hochman G, Miller KG. 2020. *Total cost of carbon capture and storage implemented at a regional scale: northeastern and midwestern United States*. Interface Focus 10: 20190065. http://dx.doi.org/10.1098/rsfs.2019.0065

[27] It is possible that pipeline owners and owners of CO_2 injection equipment will also seek a portion of the CCS tax credit for performing their service. This may result in financial arrangements that split the CCS tax credit among the capturing unit, pipeline owner, and owner of injection services. For the purposes of our analysis, we have assumed that the powerunit will capture the entire value of the tax credit, choosing instead to separate count transport and storage costs as a separate cost line-item that, given the sensitivities tested, can effectively capture the effect on power unit economics of splitting the CCS tax credit among multiple parties.

Coal	Non-CCS FOM	*2021 $/kW-year*	$43	$43	$43
Coal	CCS FOM	*2021 $/kW-year*	$0	$8	$1

5.2. CCS technology selection

Multiple technologies have been experimentally validated for power unit CCS, but as of 2022, an "amine-based solvent system" is considered the only technology commercially available at the scale necessary to deploy at power units.[28]

A post-combustion amine-based solvent CCS technology operates at the back end of a power unit and relies on the unique properties of specific amine chemicals to scrub CO_2 from post-combustion flue gas. Amines are a wide group of organic compounds derived from ammonia; several commercial vendors offer proprietary amine solvent blends formulated for commercial-scale CO_2 capture.[29] What makes these blends well-suited to CCS is their affinity to bind with CO_2, then to release it again later in the process to create a waste stream made up exclusively of CO_2.

A typical amine CCS system takes advantage of this chemistry with three core parts: a quencher, an absorber, and a stripper. The quencher's job is to reduce the temperature of flue gas for optimal CO_2 binding. Second, the absorber is where an amine solvent reacts with CO_2, pulling it from the flue gas. Finally, the stripper is where the amine solvent is heated, causing it to release the CO_2 and enabling the CO_2 to be recycled. [30] On the front end of an amine system, a booster fan is installed to maintain adequate pressure, and on the back end, a compression and dehydration system may be installed to produce CO_2 that meets pipeline standards.

One reason why CCS projects are rare in the power sector is that running a CCS system negatively affects power unit economics. An amine system, for example, increases unit costs in four ways. First, the heat needed to release bound CO_2 and regenerate the amine solvent is siphoned from the power unit's boiler. This reduces the heat available to generate electricity and increases the unit's heat rate. Second, an amine system requires electricity, which is either drawn from the power unit, reducing net generation available for sale, or produced by an auxiliary generator, adding cost. Third, the amine system itself brings additional capital costs plus operation and maintenance costs relating to general repairs and upkeep, water management, and solvent consumption. Last, captured CO_2 must be

[28] *CO_2 Capture Projects: Best Practices and Insights for Technical Due Diligence in Support of Lenders and Investors*. June 2021. Available at https://sargentlundy.com/wp-content/uploads/2021/06/CO2CaptureProjects_WhitePaper2_SargentLundy.pdf.

[29] Ibid. and Fluor (Econamine FG Plus™), Mitsubishi Heavy Industries America, Inc. (KM-CR Process® with KS-1™ solvent), Shell (Cansolv), and ION Clean Energy (Advanced Liquid Absorption System)

[30] Commonly used amine-based solvents that have been experimentally and/or commercially proven for the CO2 capture abilities are monoethanolamine, 2-amino-2-methylpropanol, methyldiethanolamine, diglycolamine, and piperazine. See Lun Ooi et al., Amine-based solvent for CO2 absorption and its impact on carbon steel corrosion: A perspective review. 2020. Available at https://www.sciencedirect.com/science/article/abs/pii/S1004954120301002

transported and stored, which can add considerable cost depending on the distance to pipelines and storage sites. Our analysis captures all of these effects.