OCED
Office of Clean Energy Demonstrations

Portfolio Insights:
Carbon Capture in the Power Sector

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Authors

Eli Bashevkin

Theresa Christian

Jonathan Chung

William Dean (lead)

Andrew Gilbert (lead)

Katelyn O'Dell (co-lead)

Chris Wu (co-lead)

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Leadership for the Portfolio Insights: Carbon Capture in the Power Sector Report

Office of Clean Energy Demonstrations: Melissa Klembara, Kelly Cummins

Office of Policy: Paul Donohoo-Vallett

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Purpose of this Report

OCED's *Portfolio Insights* is a series of reports outlining OCED's perspective on potential impacts of a given funding program area and how it will make progress on key barriers to commercialization (identified in DOE's *Pathways to Commercial Liftoff* reports and elsewhere). These documents serve to rapidly share learnings from our portfolio back out to the world to further accelerate commercialization progress. This is the initial document in the series. It covers carbon capture in the power sector.

Executive Summary

Carbon capture, utilization, and storage (CCUS) is an essential tool in realizing a decarbonized energy future in the U.S. Through the Bipartisan Infrastructure Law (BIL), the Department of Energy's (DOE) Office of Clean Energy Demonstrations (OCED) has approximately $3.5 billion appropriated to invest in further advancing the deployment of CCUS technology in partnership with the private sector. OCED's objective with these projects is to de-risk key barriers to widespread commercial liftoff as identified in DOE's *Carbon Management Pathways to Commercial Liftoff* (*Carbon Management Liftoff*) report. OCED's carbon management portfolio includes both direct air carbon capture (DAC), which removes CO_2 directly from ambient air, and point source carbon capture, which involves the capture of CO_2 emissions at their source, often by separating CO_2 from the flue gas at industrial facilities and power plants. This report describes the role that OCED projects it can play in catalyzing and accelerating the pathway to commercial liftoff for point source CCUS in the power sector.

OCED has two point source CCUS programs: (1) Carbon Capture Large-Scale Pilots and (2) Carbon Capture Demonstrations. Projects selected in these programs span a range of scales and technology maturities and support continued commercialization of CCUS across the value chain from technology providers to engineering, procurement, and construction partners, to transportation and storage providers, and beyond. By attracting co-investment from the private sector,[1] OCED enables a true partnership with industry, aligning incentives and activating significant private sector investment in CCUS. OCED's funding for projects can accelerate CCUS commercialization and unlock follow-on investments by reducing risks around cost and demand uncertainty, lack of standardized contracts and project execution partnerships, capture performance, project delivery, operational integration, transportation and storage, community benefits, and permitting.

Addressing the key barriers to CCUS commercial liftoff with OCED-funded demonstration projects can also drive cost reductions for follow-on projects. This report includes a case study examining the economic viability of retrofitting natural gas combined cycle (NGCC) power generation units with existing carbon capture technology in the ERCOT market. Using data from expert interviews and the National Energy Technology Laboratory (NETL), the case study shows that projects, like the first-of-a-kind projects in OCED's portfolio, can be economically viable today with high capacity factors, capture rates, and appropriate locations that do not require the inclusion of additional systems, such as new criteria pollutant controls, auxiliary boilers, or dry cooling technology, and are proximal to viable transportation and storage facilities. An estimated 10% reduction in levelized cost of electricity for future nth-of-a-kind carbon capture projects compared to first-of-a-kind projects could be achieved. The first-of-a-kind projects funded by OCED provide essential learnings for future projects and reduce risks for follow-on investors. Project economics could be further improved by other developments across the existing carbon capture value chain, such as the buildout of transport and storage infrastructure, and alternative carbon capture technologies to be demonstrated in programs like OCED's carbon capture Large-Scale Pilots. Combined, OCED's carbon capture programs can help lower key barriers and accelerate additional carbon capture deployment in the power sector by driving important cost reductions, infrastructure build out, and value chain development, with many of those impacts occurring as capital is spent and before projects are complete.

[1] OCED typically requires a minimum 50% cost share from private sector partners for projects.

Introduction

CCUS is a viable decarbonization technology central to meeting the goal of a net zero economy by 2050. The U.S. is already leading the world with over 22 million metric tons per annum (MMTPA) of point source carbon capture capacity across operational projects.[2] Operational carbon capture capacity in the U.S. is currently forecasted to grow to approximately 120 MMTPA by 2030 based on announced projects as of November 2023.[3] To meet the net zero goal over the next 26 years, the U.S. will need to increase carbon capture and permanent safe storage[4] capacity to between 400 to 1,800 MMTPA, a 18-80X increase from current deployments.[5]

Point source carbon capture is essential to mitigate greenhouse gas emissions from large scale power and industrial facilities, which account for approximately 700 and 1,600 MMTPA of U.S. CO_2 emissions, respectively, as of 2022.[6] For several sectors, such as natural gas processing and ethanol, the cost of capture relative to current tax credit values means that projects near viable storage sites are widely accepted as economically attractive today.[5,7] To meet decarbonization goals, however, carbon capture deployment is necessary across a wider range of CO_2 sources, including those where project economics are still developing. Point source carbon capture technology exists in the industrial and power sectors today with a few successful commercial-scale projects,[8] and additional successful commercial demonstration projects on a given plant type would provide industry and investors greater certainty about the performance of CCUS prior to financing projects.

The full deployment of carbon capture across multiple sectors can be accelerated by addressing commercial adoption risks identified in DOE's *Carbon Management Liftoff* report. The risks identified include a lack of standardization for partnership and commercial arrangements, the length and uncertainty of lead times for permitting, demand uncertainty for low-carbon industrial products, and costs for point source carbon capture on lower purity CO_2 emission streams. These risks can be addressed through two parallel efforts: (1) continued build-out of transportation and storage infrastructure by industries already adopting carbon capture and (2) strategic investment programs to deliver additional commercial demonstration projects to drive reductions in economic and technical risks in other industries which currently have few or no examples of facilities operating with carbon capture.[4]

The Bipartisan Infrastructure Law (BIL) and the Inflation Reduction Act (IRA) provide funding for both efforts. The IRA added and amended tax credits to further incentivize private sector investment in carbon capture and provided additional funding for industrial demonstrations that could include carbon capture. The 45Q tax credit provides a consistent, performance-based revenue stream to support project economics. For projects that satisfy prevailing wage and apprenticeship requirements, the credit value is $60 per metric ton of carbon captured and sent to utilization or secure geological storage in conjunction with enhanced oil recovery and up to $85 per metric ton of carbon geologically stored that is not associated with enhanced oil recovery. To qualify, projects must begin construction by the end of 2032 and the credit can be claimed for the first 12 years of operation. In addition, the BIL provided approximately $3.5B in federal funding, which OCED actively manages, to demonstrate substantial improvements in the efficiency, effectiveness, cost, and environmental performance of commercial-scale carbon capture technology applications in the power and industrial sectors. These commercial demonstration projects can accelerate wider commercial adoption of point source carbon capture technologies in the power and industrial sectors by partnering with industry to share capital risk in project development and construction.

This report provides an overview of how OCED, through its carbon capture programs, will directly address various risks to commercialization of point source capture in the power sector. The analysis in this report focuses on carbon capture deployment and cost reductions as impacted by both federal tax credits and OCED funded projects. Additional state and local policies, as well as future federal policy drivers, such as regulatory action, could also impact the rate of CCUS deployment. Future OCED Portfolio Insights reports will describe present and future impacts of OCED programs across additional technologies and sectors.

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[2] Facilities - Global CCS Institute (co2re.co)
[3] Global-Status-of-CCS-Report-1.pdf (globalccsinstitute.com)
[4] The Class VI Rule requires owners/operators to properly plug injection wells and monitor for a set timeframe established in the well permit (default is 50 years). Source: EPA 816-R-16-006 Dec 2016. Retrieved from: Final Class VI Guidance Documents | US EPA
[5] DOE's Carbon Management Pathways to Commercial Liftoff Report, April 2023
[6] EPA GHGRP FLIGHT database. (2022). Retrieved from https://www.epa.gov/ghgreporting
[7] As detailed later in this report, profitability refers to the entire production facility capturing an economic surplus while selling the primary commodity it produces, in this case power/electricity. It is not meant to suggest that the carbon capture system itself is independently profitable.
[8] Facilities - Global CCS Institute (co2re.co) – select projects include Petra Nova, Sleipner, Gorgon, Boundary Dam, Quest

Overview of OCED's Point Source Carbon Capture Programs

OCED's approximately $3.5B point source carbon capture programs are part of a broader $12B investment in carbon management research, development, demonstration, and deployment from the BIL managed across the Office of Fossil Energy and Carbon Management (FECM), the Loan Programs Office (LPO) and OCED. Collectively, these programs accelerate commercialization across the value chain from capture to transportation, storage, and utilization.

OCED manages two funding programs focused on point source capture, Carbon Capture Large-Scale Pilots and Carbon Capture Demonstrations. OCED also manages a program focused more broadly on industrial demonstrations using a variety of technologies, including point source capture, as well as the Regional Clean Hydrogen Hubs program which also involves point source carbon capture. The Carbon Capture Large-Scale Pilots program focuses on maturing novel, technologically sound carbon capture technologies yet to be proven at full scale. The Carbon Capture Demonstrations program funds commercial-scale projects using mature technologies to demonstrate substantial improvements in the efficiency, effectiveness, cost, and environmental performance for power and industrial applications. Both programs have a strong community and workforce engagement focus to support community-informed projects and equitable and environmentally responsible expansion of carbon capture operations. These programs have announced projects selected for award negotiation (selectees) totaling over $1B in federal investments across coal and NGCC power generation facilities.

Carbon Capture Large-Scale Pilots (LSP)

The goal of the LSP program is to develop a pipeline of transformational carbon capture technologies, beyond the existing and deployable technologies that are ready for demonstration projects, by significantly improving these new technologies' cost, emissions reduction capacity, and environmental performance. The LSP program has $937M in available funding through the BIL to invest in earlier-stage (technology readiness level (TRL) 5-6), pilot-to-commercial scale carbon capture systems at industrial and power generation facilities.[9] By the end of the approximately 5-year project life, these new carbon capture technologies are expected to mature to a TRL 7 and be ready for First-of-a-Kind (FOAK) commercial-scale demonstration. In the power sector, the program aims to support pilot projects of novel carbon capture technologies with the documented potential to achieve 90% capture efficiency (on par with existing carbon capture technologies) from a recommended minimum 25 MWe slipstream at an existing coal or natural gas electricity generation facility.[9]

On 2 February 2024, OCED announced its selection of four projects for negotiations for the LSP program (FOA 0002963). Two of the four projects are in the power sector: one at a NGCC plant in Kentucky and a second at a coal-fired power plant in Wyoming. Combined, these two projects represent up to a $120M federal investment in advancing innovative capture technologies. The technologies supported by these projects, one a novel solvent-agnostic technology and the other a low-cost sorbent-based technology, aim to capture a combined 248,000 metric tons of CO_2 per year. Both projects aim to either utilize or permanently store CO_2 captured from their flue streams.

Through these projects, the LSP program aims to develop and mature a new suite of capture technologies and utilization and storage options to improve project economics and make carbon capture attractive for a broader set of applications. These new technologies are distinct from existing and currently deployable capture technologies (see OCED's second point source carbon capture program, below).

Carbon Capture Demonstrations

OCED's Carbon Capture Demonstrations program has over $2.5B from the BIL to invest in commercial-scale demonstrations of existing, currently deployable, integrated CCUS technologies with the goal to catalyze significant follow-on investments from the private sector for widespread deployment across the U.S. The BIL directive for the Carbon Capture Demonstrations program requires OCED to fund projects at two natural gas electricity generation facilities, two coal electricity generation facilities, and two projects in the industrial sector. Given the varying maturities

[9] DE-FOA-0002963

across carbon capture configurations, OCED is designing discrete funding opportunities for different segments of the market. To date, DOE has released two funding opportunities under this program.

Through the first funding opportunity (FOA 0002738), OCED is investing in front-end engineering and design ("FEED") studies for prospective integrated, demonstration-scale CCUS projects that include point source capture, transportation, and utilization or geologic storage. The goal of the FEED studies is to continue to build a pipeline of demonstration-ready projects spanning the power and industrial sectors. By the end of the approximately two-year project life, projects are expected to be ready for detailed design and permitting leading to construction. In May 2023, OCED announced the FEED selectees including: three coal-fired power generating units, two NGCC power generating units, one IGCC power generating unit, and two cement facilities. Combined, the FEED studies represent over $20M in government investment, matched by $22M in private sector investment in power sector applications.[10] The full projects enabled by these FEED studies have a total carbon capture potential of nearly 15 MMTPA in the power sector alone.

Through a second funding opportunity (FOA 0002962, referred to as "Carbon Capture Demonstration Projects"), OCED is investing in later stage (TRL 7-8) commercial-scale demonstrations of integrated CCUS projects in the power and industrial sectors. The goal of the Carbon Capture Demonstration Projects program is to financially de-risk full scale projects and demonstrate improved commercial readiness across the value chain for widespread adoption. These projects are planned to operate on a continuous basis once constructed. In December 2023, OCED announced three selectees: two NGCC power plants (in Texas and California) and one coal-fired power plant (in North Dakota). Combined, these projects represent $890M in government investment. The projects have the potential to capture and store 7.75 MMTPA CO_2, which would be a >30% increase over today's capacity in U.S. CCUS deployment.[11] The selected projects will provide commercial-scale demonstrations of developed, technologically mature technologies that can be widely deployed at other power generation facilities. These investments also advance the development of carbon transportation and storage infrastructure in different regions and in saline formations in different geological settings.

Other Carbon Capture Investments

OCED also invests significant capital in carbon capture projects across industrial and hydrogen production facilities through the $6.3B Industrial Demonstrations and $8B Regional Clean Hydrogen Hubs programs. Four of the seven selected hydrogen hubs plan to use carbon capture in their hydrogen production process and build out associated transportation and storage infrastructure if needed. Of the 33 Industrial Demonstration Selectees, five have announced plans to incorporate carbon capture, utilization, and/or storage.

OCED's LSP and Carbon Capture Demonstration programs build on decades of DOE-supported research and development (R&D), piloting, and demonstrations and will support further development of a robust value chain of carbon capture solutions providers to de-risk adoption across multiple sectors. Ongoing DOE-supported CCUS pilots and demonstrations, including FECM-led FEED studies (supporting capture and storage technologies) and DOE's CarbonSAFE programs (supporting storage solutions), continue to build out the CCUS value chain jointly with OCED programs. Leveraging funding from across these programs, project delivery repetitions have the potential to drive down delivered costs, reduce project delivery risks, and encourage follow-on investment.

NGCC Case Study

NGCC Case Study Summary

The following sections contain a case study performed using data from NETL on the cost and performance of carbon capture retrofits on existing NGCCs.[12] For this case study the assumed market is ERCOT, with the carbon capture

[10] Total includes funding for the FEED study only for 5 of the 7 projects for which funding amounts were publicly announced
[11] Global CCS Institute
[12] Cost and Performance of Retrofitting NGCC Units for Carbon Capture (osti.gov)

process using liquid amine solvents. This case study is intended to be dynamic and updated as the DOE receives additional information over time. Below is a summary of the steps taken and methodologies used for the analysis.

1. Derive estimated capital expense (CapEx) intensity for the NETL B31A-BR.95 retrofit case and four other DOE-funded FEED studies. These FEED studies were finalized within the past three years and represent current cost projections for carbon capture retrofits on NGCC facilities. They are included to contextualize the reasonableness of the NETL case used for this analysis. NETL case costs have been brought into 2023$ and adjusted upwards to reflect a FOAK versus next commercial offering build.

2. Generate illustrative and directional levelized costs of electricity (LCOE) for FOAK and Nth-of-a-Kind (NOAK) cases, incorporating 25% CapEx improvement and directional 1% operating expense (OpEx) reductions. The CapEx reduction estimate is based on interviews and discussions conducted with technology providers, engineering consultants, asset developers and OCED applicants. OpEx reductions are conservatively modeled at 1%.[13] This FOAK and NOAK data is used to generate an unsubsidized LCOE with carbon capture CapEx, fuel, CO_2 transport and storage expenses, and operations & maintenance expenses. The levelized 45Q tax credit is included to show how it impacts the unsubsidized LCOE.[14]

3. Combine the LCOE analysis with historical ERCOT market data to show breakeven costs for the illustrative FOAK facility. To do so, fixed costs and marginal operating costs are overlaid against historical market clearing power prices. The levelized effect of OCED funding is included in the waterfall analysis.

The analysis in this report highlights the current projected economic competitiveness and potential future cost reductions of carbon capture retrofits using amine solvents at an illustrative NGCC power plant in the ERCOT market. This case study serves as an example of the impact of OCED funded Carbon Capture Demonstration projects in the power sector. 45Q enables the illustrative plant to operate at a high-capacity factor by bidding into the power market below common market clearing prices. The historical market clearing prices are near the FOAK breakeven points with and without DOE funding, indicating the plant would be able to capture economic surplus. While there is still uncertainty around actual FOAK costs and performance, this analysis shows an economically viable and competitive central case. The results from this analysis are directional and illustrative and should be treated as FEED-level projections.

NGCC Case Study Background

This case study supports the conclusion that a NGCC facility with a carbon capture retrofit in ERCOT can operate competitively. Key directional indicators of (1) CapEx and (2) LCOE are compared between FOAK (developed using NETL data) and hypothetical NOAK facilities with illustrative reductions to CapEx and OpEx (discussed later).[15]

The addressable market for capture retrofits on NGCC facilities (i.e., NGCCs proximate to possible CO_2 storage sites) in the U.S. is substantial, providing opportunity for wide-scale deployment.[16,17] The remaining operating lifespan of any selected plant is a key consideration, and this analysis assumes a plant that has at least a 12-year remaining operating life in order to capture the current value of 45Q. This suggests significant potential emissions reductions can be achieved with CCUS retrofits on NGCC facilities, which directly emitted ~585 MMT CO_2 in the U.S. in 2023.[18] The capture efficiency of the flue gas stream itself is modeled at 95% capture based on steady-state full load operations.[19] A single ~700 MW NGCC + CCUS facility using NETL's design would target capturing and storing ~1.7 MMTPA of CO_2, or ~8% of current U.S. CCUS capacity.[20] Note that some net emissions remain from upstream sources associated with natural gas extraction and transmission as well as onsite emissions that are not captured by the carbon capture

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[13] While OpEx reductions may exceed 1% for NOAK facilities, this analysis uses 1% for conservatism.
[14] 45Q is eligible to be claimed by the person who owns the capture equipment and physically or contractually ensures the disposal, utilization, or use as a tertiary injectant of the CO_2 https://crsreports.congress.gov/product/pdf/IF/IF11455/2
[15] Modeling 45Q as $85 per metric ton through 2027, with 2% escalation after 2027, with the first 5 years modeled as direct pay, then years 6-12 modeled as a transfer with a 10% discount, removal of leverage and financing costs, and applying 5-year construction period and 12-year operating period.
[16] Use of natural gas-fired generation differs in the United States by technology and region - U.S. Energy Information Administration (EIA)
[17] Middleton, Bennett, Ellett et al. 2022. Reaching Zero: Pathways to Decarbonize the US Electricity System.
[18] United States Environmental Protection Agency (EPA). "Clean Air Markets Program Data." Washington, DC: Office of Atmospheric Protection, Clean Air Markets Division. Available from EPA's Air Markets Program Data web site: https://campd.epa.gov/.
[19] Decreasing the capture rate from 95% to 90% has only minor effects on plant economics. NETL Baseline Study Updated to Include the Performance and Cost of High Carbon Capture Rates for Power Generation Systems | netl.doe.gov
[20] CO_2 volumes captured and stored depend primarily on underlying plant size, capture system design, performance targets and technology

system.[21] Additional CO_2 emissions could also result from startup, shutdown (SUSD) and process upsets, however these potential emissions are still under study and not incorporated as part of the case study.

OCED investments combined with the increased 45Q tax credit will further accelerate deployment by reducing key commercial risks that previous CCUS projects have faced in reaching commercial operations. Risks can relate to project execution, technical performance, commercial factors, and the regulatory environment. In particular, project execution risks include potential supply chain constraints for labor and materials, such as engineering, procurement, and construction (EPC) partners and capital equipment, as well as unplanned cost, budget, and schedule overruns. OCED funding of FOAK projects will allow the full development of detailed facility design and costing, which de-risks future builds and helps to buy down some of the market risks associated with potential cost growth. OCED investments in CCUS also aim to indirectly build out the CCUS supply chain for both labor and materials including equipment, solvents, and technical expertise as an associated benefit of direct investment in projects. OCED investments also help developers and EPCs gain repetitions and expertise to refine designs, reduce delivery risks, and solidify asset performance expectations for future projects. The case study explores the potential impacts of OCED funded projects on some of the key areas of risk discussed above, although it does not comprehensively or quantitatively capture every potential challenge that may arise with these types of projects.

CapEx: Potential Reductions Possible for NOAK Builds

As with other large infrastructure systems, industry participants anticipate cost reductions for demonstrated CCUS systems (Figure 1) to come from a combination of:

1. Reductions in project cost of capital: Project cost of capital should come down over time as replication leads to reduction in uncertainty, establishment of performance track records, and demonstration of positive cash flow economics. Cost of capital reductions can come through lower interest rates and lower cost of loans and financing, bonds, insurance, and other financial instruments used to fund the design, engineering, construction, and operation of these facilities. As the private sector learns to monetize 45Q, the transfer discounts and implementation risks associated with the tax credit should decrease as well, which will increase the value realized by the project, while the reduction in uncertainty can similarly lower borrowing costs.

2. Increased system scale: There is an observed correlation between increasing scale of a carbon capture project and decreasing levelized capture cost.[22] By scaling up projects from pilot-sized systems to larger commercial-scale facilities and flue streams, overall costs per unit of carbon captured should decrease.

3. Sunsetting of non-recurring engineering costs: This includes standardization of engineering and design for plant foundations, engineering drawings and process flow diagrams, and modularization of plants to encourage some degree of mass production of key components or systems.

4. Maturation of supply chain partner ecosystem (capture system operations, procurement): Large capital projects rely on an ecosystem of technology developers, engineering, procurement, and design firms, plant and system operators, financiers, and upstream supply chain and manufacturing partners. This ecosystem will expand and improve from the increased repetition of system design, engineering, and implementation.

5. Engineering design and materials improvements over time: These include cost engineering efforts such as improved absorber designs and sizing, optimized instrumentation, and more energy efficient equipment, as well as improved materials. The Carbon Capture Demonstration projects would accelerate this process through the design, construction, and operation of the FOAK facilities for identification of future improvements and learnings.

Many of these cost reductions will occur as capital is spent, particularly for the sunsetting of non-recurring engineering costs and the maturation of the supply chain partner ecosystem, and not at the end of the project.

To corroborate the use of the NETL data, Table 1 compares adjusted NETL base case retrofit CapEx data updated to 2023$ and adjusted to represent a FOAK versus next commercial offering build against data from four other, recent

[21] ~67% of remaining net emissions from these systems are from upstream extraction and transmission.
[22] Technology-Readiness-and-Costs-for-CCS-2021-1.pdf (globalccsinstitute.com).

DOE funded FEED studies.[23] The average CapEx intensity in terms of total overnight cost (TOC) per net MW of capacity is $1.8MM, while the adjusted NETL TOC per net MW is $1.7MM.[24, 25] The NETL case is in-line with current data, and one of the FEED studies in the sample group, Deer Park Energy Center, has substantially higher projected CapEx driven by limited laydown areas and a congested site which necessitates a more expensive design for the capture facility, as well as being a combined heat and power facility. Table 1 also shows an illustrative 25% capital cost reduction from FOAK to NOAK projects based on discussions with external technology providers, engineering consultants, asset developers, and OCED applicants. The FEED studies performed for these projects ranged from Association for the Advancement of Cost Engineering (AACE) Class 3 to 5 estimates, as classified in the AACE Cost Estimate Classification System specific to Process Industries.[26] This indicates an estimate that is based on preliminary information resulting in a wide accuracy range of -30%/+50% for Class 4 estimates, which are used at the concept screening, feasibility study, and strategic planning stages. For contrast, AACE Class 1 estimates rely on detailed and discrete project cost data, result in an expected accuracy range of -10%/+15%, and are used during the project execution phase as a baseline against which actual costs and resources will be monitored.

Source	First-of-a-Kind CapEx Intensity TOC/MW	Nth-of-a-Kind CapEx Intensity TOC/MW
Adjusted NETL NGCC CC Retrofit B31A-BR.95	$1.7MM	$1.3MM
FE0031847: Southern Co, Linde BASF	$1.6MM	$1.2MM
FE0032137: Deer Park Energy Center, Calpine	$2.3MM	$1.7MM
FE0031848: Sherman Plant, Bechtel	$1.3MM	$0.9MM
FE0031844: Mustang Station, GSEC	$1.8MM	$1.3MM
FE0031842: Elk Hills, Fluor	$2.1MM	$1.6MM

Table 1. *Illustrative Natural Gas Combined Cycle (NGCC) carbon capture facility capital expense (CapEx) intensity reduction potential in millions of dollars (2023$) per net megawatt (MW) for a first-of-a-kind and nth-of-a-kind build.[27] The CapEx presented is representative of the total project cost of the carbon capture system. The expected accuracy range is -30%/+50% based on AACE Class 4 expected accuracy.*

While capture projects are trending toward more modular designs, carbon capture is not projected to experience the same type of CapEx learning curves through productization and large-scale production as some other clean energy technologies (e.g., solar modules, lithium-ion batteries, wind turbines). Key differences arise from the magnitudes of repetitions (tens or hundreds of plants versus thousands or millions of solar panels or battery cells). Learning curves for CCUS are expected to be more like large-scale infrastructure projects such as chemical plants or thermal power facilities.

LCOE: Potential Reductions in Cost Impacts of Carbon Capture Retrofits

Together, possible CapEx and OpEx reductions could drive reductions in LCOE from FOAK to NOAK facilities (Figure 1). For CapEx, the below analysis uses the adjusted NETL B31A-BR.95 data for FOAK and NOAK projects from Table

[23] Adjustments to the NETL data have been made to translate the CapEx figures which represent next commercial offering figures in 2018$ to a FOAK representative figure in 2023$. This was done by 1) applying the high end of the estimate uncertainty (+25%) to capture island, equipment, and materials costs, 2) applying CEPCI escalation to labor, materials, and equipment, and 3) updating labor costs to regional prevailing wage (+25%).
[24] FE0031847 FEED of Linde-BASF Advanced Post-Combustion CC Technology at Southern Company NG Power Plant, FE0032137 FECM Annual Project Review, FE0031848 FEED Study for CC Plant Retrofit to NGCC Power Plant, FE0031844 FEED for Piperazine with the Advanced Stripper
[25] Using definition of "Total Overnight Cost" per NETL basis for Techno-Economic Analysis. TECHNICAL REPORT TEMPLATE AND USER GUIDE (doe.gov).
[26] 18R-97: Cost Estimate Classification System
[27] Dollars expressed are in 2023$ and escalated using CEPCI. MW expressed are net capacity, the NETL case uses 636 MW net generating capacity.

1, and a transportation and storage OpEx (T&S OpEx) assumption of $15/MT. For OpEx, DOE modeled operating, fuel, and maintenance expenses with modest cost reductions of 1%, assuming standardization and increases in overall system performance, energy efficiency, and other operating efficiencies. Combined, these result in a decrease in LCOE by ~10% for the hypothetical NOAK facility.[28] This assumes that FOAK and NOAK plants will have the same capacity factor (85%) with annual escalation in CapEx and OpEx similar to escalations in 45Q. This aligns with other studies that use hybrid engineering-economic and experience-curve approaches to estimate potential decreases in LCOE of 10%-11% for NOAK plants compared with FOAK plants.[29] Studies on the upper end of the reduction spectrum using experience curves derived from seven technologies relevant to power plants with CCUS indicate a potential 15% reduction potential in the study's NGCC base case, with up to 20% reduction if the learning starts with the first plant.[30] Notably, at $85/MT, the 45Q tax credit substantially reduces LCOE for both FOAK and NOAK plants (by over 25%).[28,31]

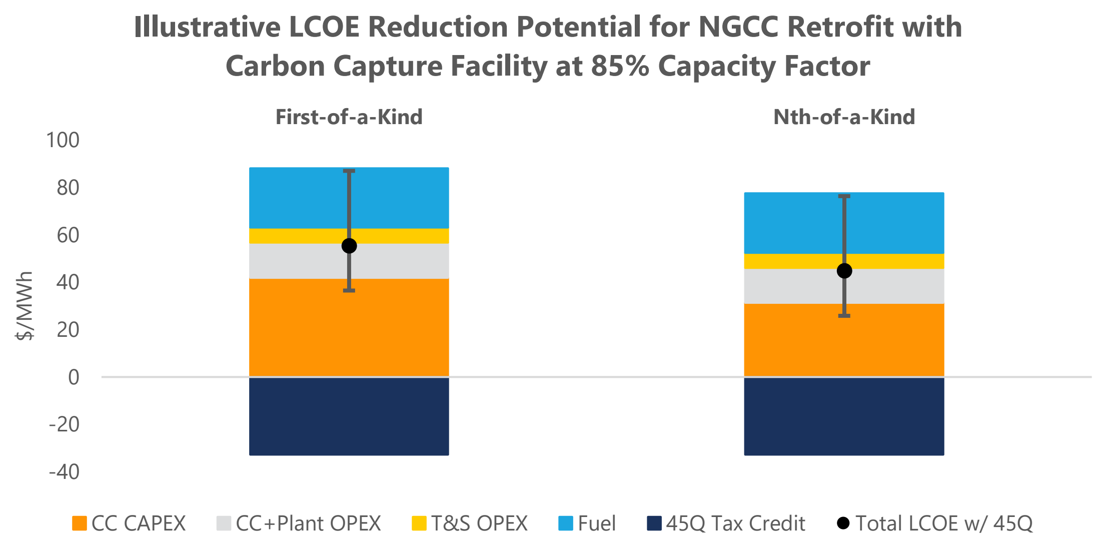

__Figure 1__[32] Levelized cost of electricity (LCOE) in units of dollars (2023$) per megawatt hour (MWh) for a first-of-a-kind and nth-of-a-kind natural gas combined cycle (NGCC) facility retrofitted with carbon capture technology. Colors indicate the components of LCOE. Black points represent the total LCOE with the 45Q tax credit and error bars indicate the uncertainty based on AACE Class 4 guidelines (-30%/+50%). Levelized 45Q tax credit is shown as negative LCOE. Project economics for projects with geologic storage through Enhanced Oil Recovery (EOR) are likely similar.[33]

Marginal Operating Expense and Market Structures

Based on the LCOE modeled above, real-world power market data (ERCOT), and a high operating capacity factor for the modeled capture retrofit (85%, detailed below), these systems can be viable today with 45Q (Figure 2). Projects funded under the Demostrations program are further derisked through OCED's capital support. OCED funding provides $270M in cost share for each of its carbon capture on gas power projects, which translates to around $10/MWh of LCOE value for the modeled ~700MW plant that provides margin for the project to buffer against potential cost growth.

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[28] Calculated using 10% weighted average cost of capital (WACC) and 12-year operating period.
[29] [Frontiers | Cost projection of combined cycle power plants equipped with post-combustion carbon capture (frontiersin.org)]
[30] [Use of experience curves to estimate the future cost of power plants with CO2 capture - ScienceDirect]
[31]Modeling 45Q as $85 per metric ton through 2027, with 2% escalation after 2027, with the first 5 years modeled as direct pay, then years 6-12 modeled as a transfer with a 10% discount, and removal of leverage and financing costs. Amortization, depreciation, the monetization of potential operating losses, and decommissioning costs are not included in this analysis. No terminal value is assigned.
[32]Total LCOE error bars derived from the capital cost and operational cost uncertainties based on AACE Class 4 guidelines but does not incorporate project execution or schedule risks, or commodity price sensitivity.
[33] EOR projects will have the following puts and takes. Use of geologic storage through EOR means projects receive $60/MT from 45Q, however, projects no longer need to pay T&S costs of ~$15/MT. The total cost for delivered CO_2 to EOR fields is ~2% of $/bbl-WTI per MCF of CO_2. At $80/bbl this is ~$30/MT CO_2. This figure, however, also includes the share paid to the midstream operator and may include wellhead compression. Impacts to LCOE are likely similar albeit subject to greater market risk vs geologic storage due to commodity risk associated with oil prices.

Under typical market conditions, power generators bid into the power market at their marginal operating cost, or the cost to produce a marginal unit of power (i.e., treating CapEx as sunk cost). Power producers are paid the "real-time market price", or market clearing settlement price, which is the price where power supply (starting with lowest cost producers to highest cost) meets market demand. As long as a plant's marginal OpEx is below the market clearing settlement price 85% of the time, that plant can operate at an 85% capacity factor.[34] To evaluate profitability, power generators look to whether the average market clearing settlement price across the times the plant operates is higher than the breakeven price, or the marginal operating cost plus fixed OpEx and CapEx contribution. Based on the NETL Baseline report, in 2017 the top twenty NGCC plants achieved capacity factors over 85%, with an average of 89%.[35]

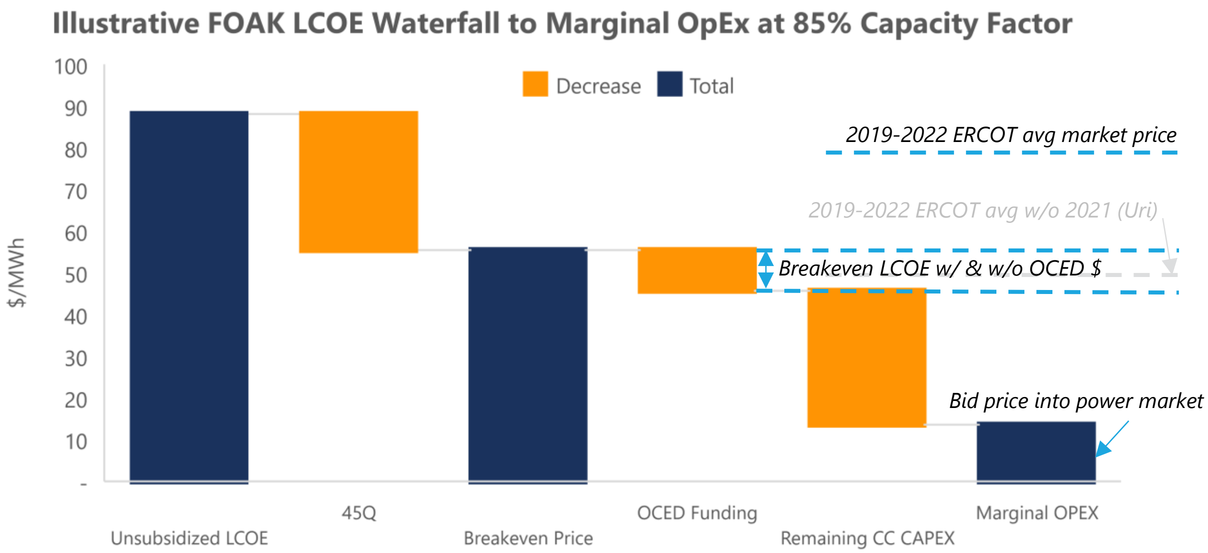

Figure 2. *Levelized cost of electricity (LCOE) waterfall chart for first-of-a-kind plant showing the total unsubsidized LCOE of a Natural Gas Combined Cycle (NGCC) facility with a carbon capture retrofit without base power plant CapEx. Unsubsidized LCOE is decreased by operational 45Q income to reach breakeven LCOE, or price per MWh required to reach operational breakeven inclusive of a rate of return on the capture retrofit CapEx. OCED Funding and capture retrofit CapEx is deducted to reach marginal operational cost of generating energy from the plant. This marginal OpEx is representative of what a plant or system operator would bid into the energy markets. For reference, the average real-time market clearing price for the ERCOT region from 2019-2022 is shown, including the impact of increased prices due to Winter Storm Uri in 2021. Prices have trended upward over the period, even controlling for Uri.[36] This waterfall is meant to be an illustrative base case, sensitivities to fuel prices, capital expenses and capacity factors are shown in the appendix.*

As illustrated in Figure 2, 45Q has a significant, positive impact on project economics. The total value of 45Q tax credits for the project is tied to the amount of carbon oxides (CO + CO_2) captured (and stored or used), which correlates directly to the capacity factor and variable operating expenses of the plant. At $85/MT of carbon oxides, the value generated from 45Q reduces the breakeven price for projects to below historical market clearing settlement prices and covers most of the variable operating expenses (fuel, carbon transport and storage, etc.) associated with the plant. Backing out CapEx from the breakeven price, marginal OpEx is low, higher capacity factors become achievable, and plants can be economically attractive. For example, this analysis depicts an illustrative NGCC with a CCUS retrofit at an 85% capacity factor enabled by structure of the 45Q tax credit, whereas average capacity factor for existing NGCCs was 57% in 2022.[37]

The breakeven LCOE is modeled with a 10% internal rate of return (IRR). Other value adders not included in this simplified analysis are the impacts of:

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[34] Plant capacity factors are also impacted by planned and unplanned outages.
[35] NETL Cost and Performance Baseline for Fossil Energy Plants. Volume 1: Bituminous Coal and Natural Gas to Electricity (2022)
[36] Independent Market Monitor for ERCOT 2022 State of the Market Report 2022annualreport.pdf (texas.gov)
[37] Natural gas combined-cycle power plants increased utilization with improved technology - U.S. Energy Information Administration (EIA)

- Energy Attribute Credits (EAC), or the value associated with providing low-carbon energy, similar to a Renewable Energy Credit (REC) for renewable energy projects.
- Depreciation and other potential tax benefits.
- Leverage, or the use of debt to increase the returns for equity investors in the project.

Incorporating and quantifying these common value adders would lower the LCOE and make returns for a project more attractive than depicted in this analysis.

Differences in plant location, including distance to existing CO_2 transport and storage options, will influence the physical performance and economics of the plants. Physical factors include differences in ambient site conditions such as elevation, barometric pressure, ambient air temperature, cooling water temperature and makeup. Commercial factors include transportation of supplies and equipment, local labor supply availability and supply chain considerations that may be inherent to a specific site location.[38]

Extensibility Across Fossil-Based Power: Coal-Fired Generators

Carbon capture projects on coal-fired generator units could experience the same CapEx and OpEx improvements described above. CCUS for coal-fired facilities is further along the maturation curve, with two commercially operating CCUS facilities on coal-fired generators in North America: Petra Nova and Boundary Dam. Notably, Carbon Capture Demonstrations selectee Project Tundra could directly benefit from cost reductions through project repetitions described in the sections above due to its existing partnership with EPC provider Kiewit and technology provider Mitsubishi Heavy Industries America (MHIA), both of whom were key partners on the Petra Nova project. Furthermore, Project Tundra will use MHIA's updated "advanced KM CDR process" with its reformulated KS-21 solvent, which enables more efficient capture compared to Petra Nova's capture system.[39]

In terms of delivered power costs, carbon capture retrofits on coal power result in higher unsubsidized LCOE than those on NGCCs, but the value of the 45Q tax credit is also greater. Both effects are primarily driven by the higher carbon content in coal flue streams (12-15% for coal power versus 4-5% from NGCC flue streams).[40] On a per MW basis, higher carbon content in coal systems leads to larger capture systems and higher capital costs, while higher OpEx intensity is driven by additional flue gas treatment needs and higher parasitic load (these systems have to do more capture work for a given amount of power).

Additional Impacts on Drivers of Commercial Liftoff

Beyond the CapEx and OpEx reductions, the LSP and Carbon Capture Demonstration programs will address additional risks faced by CCUS projects around transportation and storage infrastructure and value chain maturity. By providing anchor volume (adding >30% to today's capture capacity), OCED funded CCUS projects can unlock funding for pipeline construction and spur additional storage well development. OCED programs will create pools of suppliers, vendors, and delivery partners that will continue to grow with adoption. The broader $12B suite of carbon management programs at DOE will further support development in both these areas. To support an informed, connected deployment effort, DOE's Carbon Matchmaker provides an online information resource to connect users across the carbon capture, utilization, and storage and carbon dioxide removal value chain.

[38] Cost and Performance Baseline for Fossil Energy Plants Volume 1: Bituminous Coal and Natural Gas to Electricity. DOE/NETL. Oct 2022.
[39] Public information. https://www.projecttundrand.com/post/project-tundra-moves-into-final-development-stage, https://www.kiewit.com/projects/petra-nova-carbon-capture-project/
[40] Point Source Carbon Capture from Power Generation Sources | netl.doe.gov

Transportation and Storage

The continued build-out of transportation and storage (T&S) infrastructure will help to accelerate project deployment. While T&S costs are a smaller share of total costs for most CCUS projects compared to capture,[41] CCUS projects need T&S to achieve their goals. Private market activity in enhanced oil recovery and active carbon capture sectors (e.g., ethanol refinement) have supported existing CO_2 pipeline and storage well development. DOE programs, including the CO_2 Transportation, Infrastructure, Finance, and Innovation (CIFIA) program managed by LPO, FECM's CarbonSAFE and FEED funding programs, and OCED's LSP and Carbon Capture Demonstration programs (which include T&S), as well as the expanding market opportunity across industrial and power facility CCUS will continue to support infrastructure expansion. Cost declines and project viability are achievable through building shared regional pipeline networks, compared with higher-cost rail and truck transport.

Close engagement with states, local communities, and key stakeholders is an essential component of potential pipeline construction projects and storage site development. Several OCED funded projects include proposed CO_2 pipeline construction to transport captured CO_2 to sites for safe, long-term geologic storage. These OCED funded projects will aim to demonstrate best-in-class community engagement to increase the likelihood of project success. All OCED funded projects are required to submit and execute a Community Benefits Plan with regular community engagement. In addition, OCED conducts meaningful, two-way engagement throughout the project lifecycle with key stakeholders, including local communities and regulators. Outreach and engagement with local communities and state regulators, on key issues including risk management, safety, and emergency response, will continue to be essential to explore and respond to public concerns surrounding future pipeline projects and storage well development.

OCED and other DOE carbon management programs could also aid the expansion of geologic storage. North America has abundant subsurface storage resources for CO_2, ranging anywhere from 2,400 to 21,000 billion metric tons of potential storage resources.[41] However, before CO_2 can be injected, storage sites first need to be characterized and determined to be safe for use (e.g., CO_2 injection will not negatively impact underground sources of drinking water and public health). DOE programs seek to reduce the cost and deployment timeframes for further developing storage infrastructure. DOE's CarbonSAFE initiative supports the development of geologic storage sites across the U.S.[42] The Environmental Protection Agency (EPA) has developed Underground Injection Control Program requirements for geologic storage wells (also known as Class VI wells). EPA has a goal of reviewing well applications and issuing permits, when appropriate, within approximately two years.[43] As of January 2024, EPA has permitted four active Class VI wells and four pending wells. EPA has also approved three states to be the primary enforcement authority ("primacy") for Class VI well permitting within their borders: Wyoming, North Dakota, and Louisiana. These states are aiming for shorter permitting timelines and Wyoming and North Dakota have already approved wells. Other states (Texas, West Virginia, and Arizona) are taking steps toward primacy approval,[44] and industry groups are pushing to accelerate the permitting process.

Additional Value Chain Development

OCED investments in capture projects can help mature the less robust portions of the CCUS value chain, including emerging equipment suppliers, technical expertise, and commercial partnership standardization. The supply chain for point source amine-based capture technology is robust and resilient,[45] and OCED funded CCUS projects could trigger rapid scale up of production capacity for these suppliers. More nascent technologies will require the development of new supply chains. OCED funded LSP projects could help grow the number of commercially viable capture technologies and suppliers applicable to power and industrial sectors. These pilots aim to prove out operations and economics at smaller scales to de-risk investment in full-scale commercial facilities.

Scale up of CCUS will utilize and require technical experts and workers in skilled trades (e.g., electrical, plumbing, and mechanical trades), energy sector, and manufacturing. Continuing to invest in this workforce will be key to supporting a robust domestic carbon capture industry.[41] Community benefits plans for OCED funded projects help address this challenge through one of their four core policy priorities: investing in the American workforce. Investments for selected CCUS projects include workforce development for skilled and technical jobs through partnerships with universities, on-

[41] DOE's Carbon Management Pathways to Commercial Liftoff Report, April 2023
[42] CarbonSAFE Initiative | netl.doe.gov
[43] Class VI - Wells used for Geologic Sequestration of Carbon Dioxide | US EPA
[44] Primary Enforcement Authority for the Underground Injection Control Program | US EPA
[45] The Carbon Capture, Transport, and Storage Supply Chain Review: Deep Dive Assessment | Department of Energy. February 2022.

the-job training through registered apprenticeships and offering paid internships that provide high quality work with competitive pay.[46,47]

Finally, commercial standardization across later stages of the value chain for at-scale projects is critical (e.g., pipeline and storage agreements). OCED funded projects are creating demand for essential project execution partnerships in the private sector from technology providers to industrial emitters and EPC firms to pipeline and storage site operators. The development of these relationships, and emergence of standardized commercial contracting terms through OCED's programs can reduce partnering frictions and serve as examples for future projects.

Conclusion

DOE's funding for CCUS projects in the power sector can lower key barriers and accelerate commercial liftoff of CCUS in the U.S. power sector. OCED's investments in point source capture projects in the power sector across two programs can drive important cost reductions, critical infrastructure build-out, and value chain maturation. FOAK projects co-funded by OCED and industry partners will provide essential learnings for future projects and reduce risks for follow-on investors. The case study analysis of NETL data indicates that cost reductions, in conjunction with the 45Q tax credit, could make widespread deployment of carbon capture retrofits on NGCC power plants economically competitive.

[46] OCED Selects Three Projects in CA, ND, and TX to Reduce Harmful Carbon Pollution, Create New Economic Opportunities, and Advance Carbon Reducing Technologies | Department of Energy
[47] OCED Selects Four Projects in KY, MS, TX, and WY to Advance Technologies to Reduce Harmful Carbon Dioxide Emissions | Department of Energy

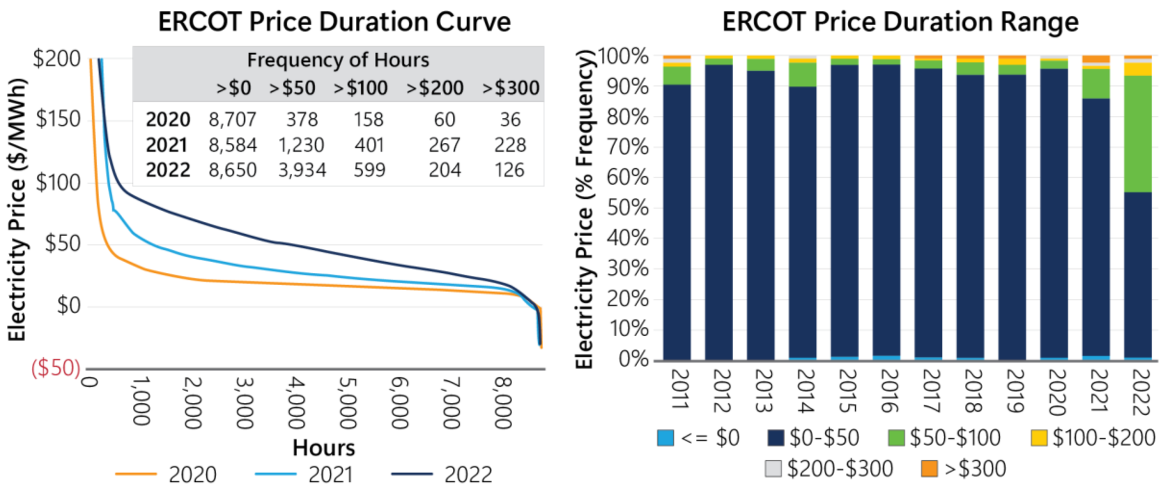
Appendix

Modeling Methodology

This analysis is meant to be illustrative, directional, and conservative. The modeling performed in this paper uses annual periods and simplified assumptions and inputs that provide appropriate, directional outputs. Simplifications include the intentional omission of leverage, depreciation, the monetization of operating losses, tax equity and a 10% discount on the value of transferred tax credits. Conservative assumptions were applied where possible to provide directionally accurate but conservative outputs. Examples include adjusting NETL baseline CapEx to the high end of the error range, a strict 12-year asset life, excluding energy attribute credits, etc. This analysis represents a single illustrative plant based on FEED-level data, and not final investment decision costs for all plant configurations. This appendix also contains sensitivity tables on three critical variables: fuel cost, capacity factor, and CapEx.

ERCOT Price Duration Curve and Range

Figures 3 and 4 show market data from ERCOT that supports the ability of assets to operate at higher capacity factors (~85%) due to marginal operating economics discussed in the NGCC case study. Figure 3 illustrates that the market clearing settlement price within ERCOT lies above the illustrative FOAK plant marginal OpEx (~$10) for most hours within the year. Figure 4 shares summarized longitudinal pricing data back to 2011 for ERCOT. These are provided as market reference point data in the ERCOT market as a compliment to the individual power plant asset-level economic analysis performed in the case study.



Figures 3 and 4. *ERCOT Price Duration Curve and Range (adapted from Figures A3 and A4 in source report, respectively).[48] The price duration curve shows the cumulative number of hours where electricity prices were above a certain price in $/MWh for the years 2020 through 2022. The price duration range graph shows the percent frequency where electricity prices are within certain bands from <=$50/MWh to >$300/MWh in $50/MWh to $100/MWh increments.*

While the case study leverages EIA's 2023 Annual Energy Outlook (AEO) natural gas curves, project economics are sensitive to natural gas prices (fuel makes up >50% of modeled OPEX).[49] Lower cost natural gas makes these projects more attractive. Table 2 below shows the sensitivity of the case study's modeled FOAK plant's marginal OpEx and LCOE to the price of natural gas. If prices for natural gas are low enough (~$2 or below) then the illustrative FOAK facility modeled in the case study could bid into power markets at below $0 per MW. All else equal, movements in marginal OpEx directly impact breakeven cost, so if marginal OpEx goes down or up, then breakeven LCOE for the facility goes down or up by the same amount. While changes in natural gas price would impact competing natural gas-

[48] Independent Market Monitor for ERCOT 2022 State of the Market Report 2022annualreport.pdf (texas.gov)
[49] Per EIA, Henry Hub spot prices as of 2/26/2024 were below $2.

operated power plants in the same direction, higher natural gas costs could challenge the economics of CCUS retrofits in the face of competition from power generation sources that do not consume natural gas as fuel.

Sensitivity Analysis

Sensitivity to natural gas price ($/MMBtu) - base case assumes $3.44/MMBTU over asset life based on 2023 AEO West South Central price curve

($/MWh)	1	1.5	2.0	2.5	3.0	3.5	4.0	4.5	5.0	5.5	6.0	6.5	7.0	7.5	8.0	8.5	9.0
LCOE - Unsubsidized	70	74	78	81	85	89	92	96	99	103	107	110	114	118	121	125	129
Breakeven LCOE - incl 45Q	38	41	45	49	52	56	60	63	67	70	74	78	81	85	89	92	96
Marginal OpEx	(4)	(1)	3	7	10	14	18	21	25	29	32	36	39	43	47	50	54

Table 2. *Sensitivity table illustrating the effects of changes in the price of natural gas ($/MMBtu) to the unsubsidized LCOE, breakeven LCOE including 45Q, and Marginal OpEx ($/MWh) of the carbon capture retrofitted NGCC plant base case. Highlighted case is the AEO 2023 West South Central Natural Gas price for electric power is approximately $3.44 per MMBtu over the course of the projected asset life.*[50]

Capacity factor is a critical driver of plant economics. The below sensitivity table (Table 3) accounts for the non-linearity within the 60%-90% range through separation of fixed and variable expenses but does not further account for non-linearity in carbon capture plant and NGCC performance and OpEx in the lower capacity factor ranges (<50%). Modeling shows that incentives such as 45Q mitigate the cost premium for low carbon electricity from fossil and provide the mechanism that support higher capacity factor operations as compared to many fossil generation assets that operate as load followers.

Sensitivity to capacity factor (%) - base case assumes 85% capacity factor

($/MWh)	60%	65%	70%	75%	80%	85%	90%
LCOE - Unsubsidized	110	104	99	95	91	88	85
Breakeven LCOE - incl 45Q	76	71	66	62	59	55	53
Marginal OpEx	17	16	15	15	14	14	13

Table 3. *Sensitivity table illustrating the effects of changes in the capacity factor to the unsubsidized LCOE, breakeven LCOE including 45Q, and Marginal OpEx ($/MWh) of the carbon capture retrofitted NGCC plant base case. Highlighted case is the assumed capacity factor of 85% annual average over the course of the projected asset life.*

Over the course of project development, costs can evolve as designs become more robust and projects approach final investment decision. Table 4 highlights impacts of overruns to CapEx and can similarly be used to understand impacts of inflation beyond the target Fed rate on projects, as 45Q does not adjust for inflation until 2027. Similarly, inflation within specific sectors or for certain items (e.g., construction or compressors) may potentially exceed adjustments to 45Q.

Sensitivity to CapEx overrun (%) - base case assumes $1.7MM TOC/MWnet

($/MWh)	-30%	-20%	-10%	0%	10%	20%	30%	40%	50%
LCOE - Unsubsidized	76	80	84	88	92	97	101	105	109
Breakeven LCOE - incl 45Q	43	47	51	55	60	64	68	72	76
Marginal OpEx	14	14	14	14	14	14	14	14	14

Table 4. *Sensitivity table illustrating the effects of CapEx overrun to the unsubsidized LCOE, breakeven LCOE including 45Q, and Marginal OpEx ($/MWh) of the carbon capture retrofitted NGCC plant case. Highlighted case is using the $1.7MM TOC/MWnet figure with no overruns. This table can also be used to assess the effects of increases in the cost of materials, equipment, and labor as a percent of CapEx.*

[50] U.S. Energy Information Administration - EIA - Independent Statistics and Analysis

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