ENERGY FUTURES INITIATIVE

Turning CCS projects in heavy industry & power into blue chip financial investments

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EXECUTIVE SUMMARY

The United States has reinforcing goals of 50-52% CO_2 emissions reduction from 2005 levels by 2030, and net zero emissions by 2050. To reach these goals will require an immense mobilization of resources, private capital, and innovation to support accelerated scale-up of current technologies (e.g., solar and wind energy, vehicle electrification, etc.), and emerging solutions. Carbon capture and sequestration (CCS) — the capture of point source CO_2 emissions and permanently storing them in geologic formations — is a critical component within a portfolio of decarbonization solutions. CCS can materially reduce the overall cost of achieving U.S. decarbonization goals, while mitigating several hundred million metric tons of emissions per year. It can be deployed across various kinds of power and industrial applications, helping multiple sectors support the overall decarbonization mission. CCS can enable negative emissions via bioenergy and direct air capture with carbon capture and storage, and help jumpstart the low-carbon hydrogen economy. CCS can deploy a talented workforce to a growth industry (carbon management) and leverage existing infrastructure and expertise in creating new economic opportunities on the order of tens of billions of dollars in incremental investment. However, it will take concerted policy action — building on existing momentum — to make these promises a reality.

Without "sticks," the policy of "carrots" for accelerating the development and deployment of CCS as a decarbonization technology must be generous and stable enough to attract the necessary private capital.

Several variants of carbon capture are well-established and already in commercial use across such industries as natural gas processing, urea production, and petrochemical production from coal gasification. In the U.S., there are thousands of miles of oilfield-serving pipelines that inject CO_2 underground for enhanced oil production purposes. All the basic elements of the CCS value chain - capture, transport, deep underground injection, and ongoing monitoring — have been deployed in various commercial applications in the U.S. for decades. As a key approach to greatly reducing CO_2 emissions from fossil fuel combustion and industrial processes, the elements of this value chain now need to be configured and deployed as a cohesive decarbonization solution.

Despite existing capabilities, CCS progress to date as a decarbonization solution in the U.S. has been disappointing. A fundamental reason for this is simple: CO_2 emissions are not restricted or priced at the national level. If such requirements existed with a sufficiently stiff cost — as, for example, is the case for pollution discharges into water or sulfur emissions into the air — then there would be a clear commercial impetus to avoid such penalties by reducing emissions via deployment of CCS. Clearly, a significant CO_2 emissions price would dramatically enhance the case for CCS, but such a price is not anticipated in the U.S. anytime soon.

Without "sticks," the policy of "carrots" for accelerating the development and deployment of CCS as a decarbonization technology must be generous and stable enough to attract the necessary private capital. However, until very recently and albeit in only specific cases, the federal support mechanisms of corporate income tax credits — offered on a per metric ton of CO_2 sequestered basis — have not been large enough to cover the capital and operating costs of CCS, especially when given the challenges associated with first-of-a-kind deployments. Importantly, to kick-start at-scale investment in CCS as a decarbonization solution there are two fundamental challenges that need to be addressed: application heterogeneity and value chain complexity.

Application heterogeneity refers to the deployment of CO_2 capture technologies in new industrial settings. Current carbon capture technologies have been engineered and optimized for specific flue gas characteristics such as temperature, pressure, CO_2 concentration and the presence of other chemicals and impurities. While there is considerable expertise and experience in these settings, the same cannot be said for the variety of retrofit scenarios across industrial and power sector applications — settings for which carbon capture is key to materially reduce emissions. It will take effort to tune carbon capture to each new heterogeneous application and, crucially, progress in one setting may not translate seamlessly to another. Each new application of carbon capture is a first-of-a-kind; to drive down costs and build up commercial confidence in each commercial setting, the innovation of multiple applications needs to occur in parallel.

Importantly, to kick-start at-scale investment in CCS as a decarbonization solution there are two fundamental challenges that need to be addressed: application heterogeneity and value chain complexity.

Value chain complexity refers to the four links that connect a CO_2 capturing industrial facility to permanent geologic storage: capture, transport, deep underground injection, and ongoing monitoring. Each of these four value chain links are industries unto themselves, much like the oil sector is divided into exploration, production, midstream, refining and distribution subsectors. As such, CCS is a complex decarbonization solution that requires integration across markets, technologies, and geographies to be functional. Moreover, each of the four CCS links are currently regulated relatively independently from each other, with little coordination across federal, state, and local agencies. Taken together, the nascency of CCS economic, infrastructure, and regulatory regimes effectively saddles potential developers with a multitude of risks for each of the four links in the value chain. The complexity and compounding financial risk attendant to managing these four links simultaneously makes CCS a distinctly challenging decarbonization solution.

On a risk-adjusted basis, even in the presence of greater financial support mechanisms, CCS remains challenged relative to most other kinds of development when it comes to attracting investment capital. Given such conditions, now is a critical time to develop a coordinated, comprehensive, long-term set of incentives as well as improved market, permitting, and regulatory policies. All these are needed to attract billions of dollars of private sector financial capital and widen the application of CCS to key industries. Without private capital to leverage public investment, CCS will not scale up and a key solution will remain lacking, and by such postponement, driving up the overall cost of decarbonization.

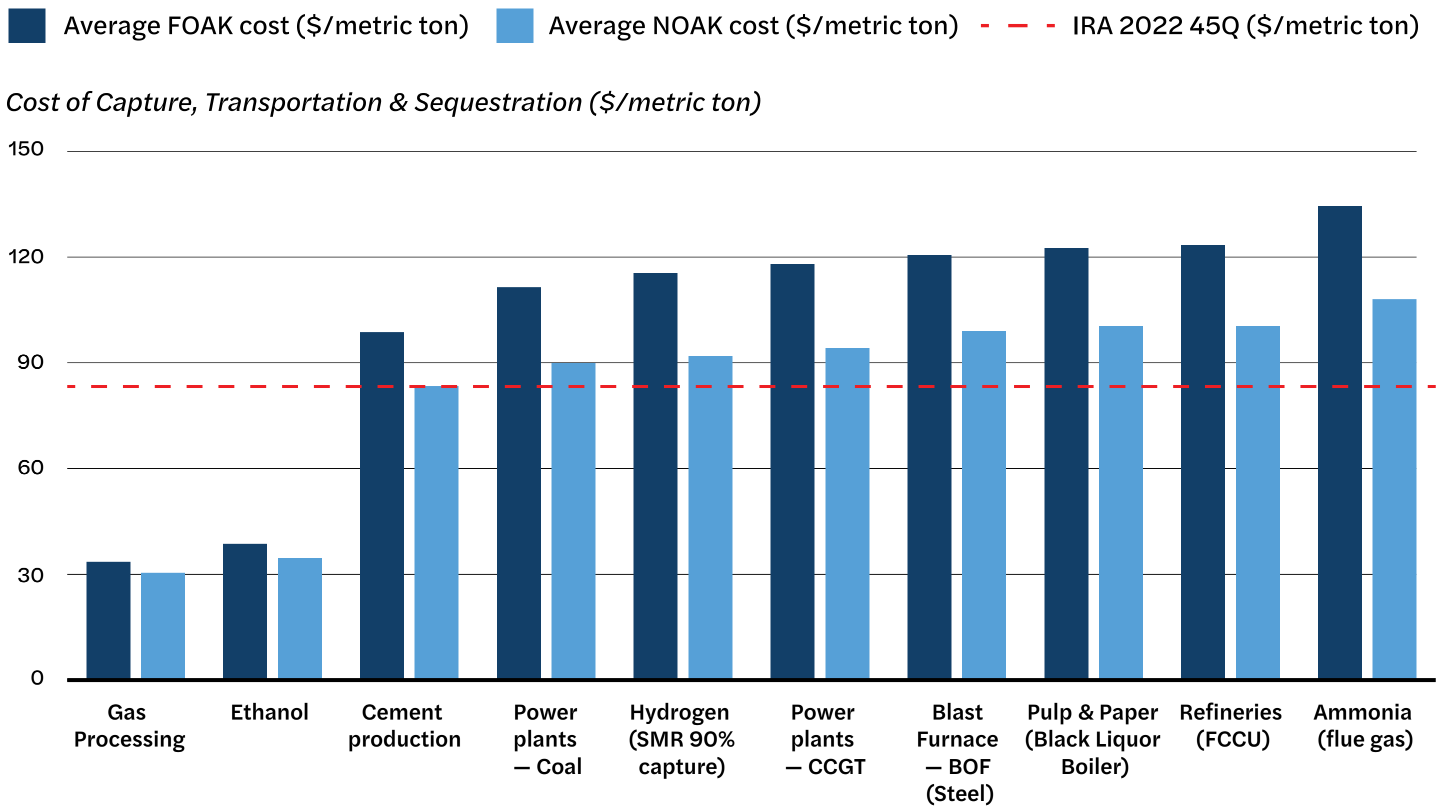
Yet, there is hope. Significant progress has been made over the past five years to jumpstart the CCS industry through a series of complementary regulatory and legislative actions. The investment case for CCS deployment in several industries, such as ethanol production and gas processing, has been markedly improved. In addition, the passage of the Bipartisan Infrastructure Law (BIL) in late 2021 provides $12.1 billion of funding to carbon management to 2026, the majority of which is allocated to grants designed to support demonstration of multiple CCS projects. The Inflation Reduction Act (IRA) signed into law in mid-August 2022 provides an enhanced Section 45Q federal corporate income tax credit value of $85/metric ton for CCS tied to geologic sequestration. Crucially, IRA made this tax credit available to a new set of non-corporate CCS facility owners, allowed tax credit transferability, and in some circumstances allowed owners to receive cash as opposed to a non-cash tax credit. In combination, these two landmark bills (the BIL and IRA) are considered gamechangers for CCS. Some analysts project that the annual quantity of CO_2 captured and sequestered in the U.S. could reach 450 million metric tons by 2035, spurring many billions of dollars of investment.

This study identifies six broad themes regarding the investment challenges for CCS that are consistently raised by project owners, developers, and investors, and offers policy recommendations to address said challenges to attract private capital.

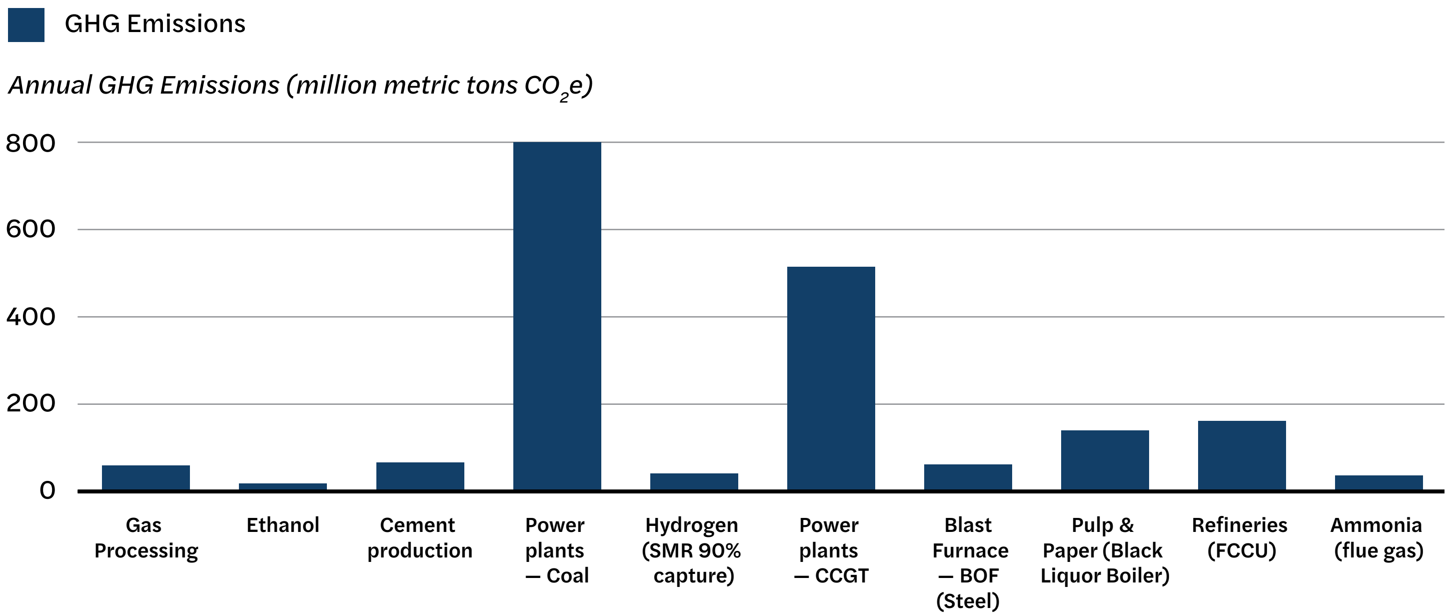
While the bold steps offered by the BIL and IRA to support CCS are significant, further policy action is needed to materially deploy CCS to help decarbonize the U.S. stock of electricity and industrial facilities. In many cases, these policy changes are not costly, but their absence may dissuade significant capital flows to first-of-a-kind applications (FOAK). Without FOAK deployment in a variety of CCS applications to start the learning process, necessary cost reductions will simply not appear. Specifically, CCS deployed for steel, pulp mill wood-byproduct boilers, natural gas and coal-based generation and hydrogen production using steam methane reformers are all currently out-of-the-money (i.e., more expensive than the value of the credit) for FOAK and in some cases mature Nth-of-a-kind (NOAK) installations. Crucially, these out-of-the money CCS applications make up the bulk of CO_2 emissions from the U.S. electricity and industrial sectors (ES-1a and ES-1b, next page).

This study identifies six broad themes regarding the investment challenges for CCS that are consistently raised by project owners, developers, and investors, and offers policy recommendations to address said challenges to attract private capital. These themes are related to a mix of supply and demand side issues (Theme 1 and 2); informational and industrial coordination barriers (Theme 3 and 4); and environmental and economic justice concerns (Theme 5 and 6).

ES–1A | By industry comparison of calculated First-of-a-kind (FOAK) & Nth-of-a-kind (NOAK) $/metric ton cost of CCS to the Inflation Reduction Act tax credit incentive



ES-1B | By industry comparison of annual (2021) GHG emissions in million metric tons CO_2e (EPA FLIGHT data)



Theme 1: Light at the end of the deployment tunnel — supply & demand incentives

Application heterogeneity coupled with value chain complexity requires CCS developers and investors to develop several interdependent, new industries *de novo*. These commercial entities — including technology providers, constructors, emitting facility owners, investors, and lenders — must see a clear, long-term, durable trajectory of policy support mechanisms driving CCS applications from early commercialization ventures to routine deployment. If the prospects of such a successful trajectory are weak, these entities will not see a commercial rationale for deploying the financial and human resources needed to develop CCS. In response, the necessary policy support mechanisms take the form of both supply (cost) and demand (revenue) incentives.

First mover CCS projects in most power and industrial applications will require supplemental support beyond the $85/metric ton tax credit through a mix of grants and loans to reduce costs enough to garner the interest of private capital. This action would facilitate the deployment of FOAK facilities, initiating a cycle that catalyzes learning effects, leading to CCS cost and operational efficiencies in subsequent installations. Since most near-term CCS projects will involve retrofits of existing power and industrial facilities, each with its own idiosyncrasies and need for significant customization, it is only through the accumulation of experience via multiple deployments across multiple industries that long-run cost reductions found in NOAK installations can be realized.

Complementing cost reducing policies are those that spur demand for CCS, such as clean energy standards within electricity generation. Clean, firm baseload power in the form of CCS coupled to existing (and new) fossil fuel generation is needed to help cost-effectively decarbonize the electric sector. This is especially important with increased electrification of industry, buildings, and transportation. Including CCS within state-level procurement standards, combined with updates to electricity market dispatch rules, offers a durable demand signal needed to help form a new carbon management industry.

Supply & demand incentive policy recommendations

- The Department of Energy should in part target BIL commercialization grant funds to the first three-to-five installations in key industries to supplement the current $85/metric ton tax credit, essentially providing low-cost equity to first movers. Additional grant funding totaling $3.2 billion would be needed to accomplish the necessary mixed funding across the six highest-emitting industrial sectors.

- Congress should allow the Department of Energy to issue loans through the Loan Program Office (LPO) to projects receiving grants as part of FOAK commercialization deployments.

- LPO should administratively update its rules to allow loans to 4th and 5th of a kind CCS installations Current regulations ban an LPO loan for CCS if the subject project technology has been used in 3 or more commercial facilities in the U.S. that have at least 5 years of operating history.

- States should modify state clean electricity procurement standards to allow fossil fuel generation with CCS to become an eligible compliance solution.

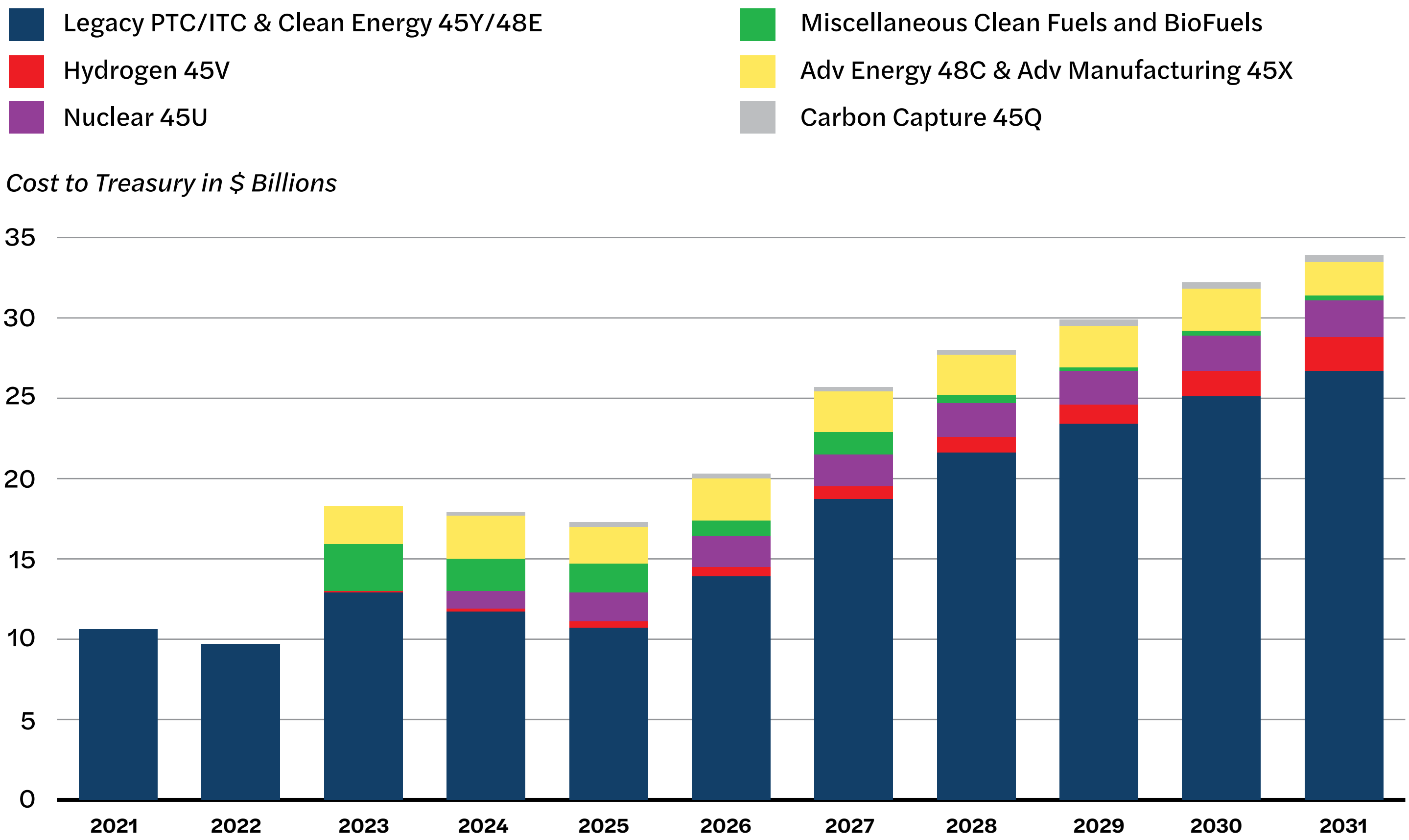
- State regulators and deregulated electricity market authorities should update market rules to allow either take-if-available energy contracts under Power Purchase Agreements or clean capacity payments (e.g., zero emission credits), for CCS-enabled fossil plants to ensure levels of dispatch for clean baseload power sufficient to ensure project financial feasibility.

Theme 2: Tax credits need to become more efficient and accessible

The passage of the IRA will lead to an expansion of the clean energy corporate income tax credit market from ~$10 billion per year (2021 and 2022, measured in terms of cost to the Treasury in forgone tax revenue) to ~$34 billion per year in 2031 (Figure ES-2). Moreover, the IRA also made considerable improvements to the usability of 45Q, specifically the direct pay and transferability provisions.

This CCS focused tax credit is eligible for "direct pay" provisions for the first five years of the incentive for (tax-paying) private parties, followed by seven years of enhanced transferability for corporate taxpayers. Tax-exempt entities such as governmental, cooperative, and tribal owners of CCS projects can now use direct pay provisions for all 12 years of claiming the credits. Key proposed benefits of direct pay include: its simplicity (refund of cash issued as part of a corporate tax return) and value certainty (100 cents on the dollar provided all reporting requirements are satisfactory and true). A crucial intended benefit of transferability is the ability to allow developers who earn tax credits to transfer them to another party in exchange for cash, should they deem doing so as beneficial. Taken together, these provisions promise an increased value of 45Q to developers while expanding the market of would-be consumers of tax credits.

ES-2 | Aggregation of U.S. Congress Joint Committee on Taxation scoring of pre-IRA and IRA energy related corporate tax credits (net of direct pay)



Attracting new participants to make use of ("monetize") transferred tax credits, thereby creating new sources of financial capital for CCS projects, should be a first-order priority of policymakers. The current pool of tax credit consumers has limited capacity to monetize additional credits, given a combination of relatively low corporate tax rates and longstanding federal limitations on a corporation's pre-credit federal tax liabilities that can be offset using corporate tax credits. In theory, there is more than enough remaining taxable corporate income across all sectors of the U.S. economy to fully utilize the new tax credit supply generated by IRA. However, most of these firms are not familiar with federal clean energy tax credits. As a result, it is imperative that well implemented direct pay and transferability rules create the conditions to attract the needed participants to monetize the opportunities presented in the IRA. Further, consideration should be given to allowing tax-exempt pension funds and charitable foundations to benefit from the same IRA direct pay provisions as tax-exempt entities. Tax-exempt pension fund and foundation fiduciaries have the financial sophistication to use direct-pay tax credits; otherwise, with no direct taxes owed to the federal government, they cannot easily use traditional non-refundable/non-cash tax credits.

Tax credit incentive policy recommendations

- The IRS should ensure that the new regulations required to implement the 45Q direct pay and transferability provisions of IRA are designed in a manner that will be conducive to bringing a broader range of new buyers into the market.
- Congress should consider expanding the pool of eligible entities able to make use of all clean energy tax credits.

Theme 3: Critical data and knowledge exist on capture and geologic storage; increasing its availability and accessibility would accelerate commercialization

Detailed data and knowledge about carbon capture technology and geologic storage characterization, cultivated over decades through federally funded research programs, represent a valuable informational resource that could be used to accelerate CCS development. Potential changes in how technical data concerning carbon capture technology and geologic sequestration sites are characterized, aggregated, and made accessible could unlock that value for potential developers.

Yet not all this information is readily accessible in a form that would-be CCS developers could use to inform critical investment and design decisions. The general result is a reduction in the pace of potential new solution development, as well as an increase in development costs across the value chain because project designers, sponsors, and regulators do not fully benefit from knowledge spillovers. There needs to be a balance struck between rewarding the federal grantee who has put resources at risk and supporting would-be follow-on developers who could benefit from learning from first movers. Further, there needs to be a focus on taking new and existing data originally collected for research purposes and developing tools useful for commercial development.

Information sharing from federally funded projects policy recommendations

- The Department of Energy should require that all key engineering performance data be disclosed by the funding recipient to the Department as a condition of awarding competitively procured cost-sharing agreements for carbon capture projects. Without infringing upon private corporate intellectual property or patents, DOE should subsequently negotiate timely and comprehensive public disclosure of such information with the funding recipient.
- The Department of Energy should allocate additional funding to aggregating existing data, collecting new data, and building tools to support geologic sequestration commercial development. EDX — the energy database managed by NETL — is a comprehensive repository of curated public and private data and analytical tools for geologic resources. Additional funds beyond the BIL are needed for EDX to aggregate data across state and federal agencies and build tools needed to help reduce the development risk of geologic storage sites.
- The Office of Information and Regulatory Affairs (part of the Office of Management and Budget) should take the initiative to harmonize federal air pollution databases to facilitate identification and screening of facilities amenable to CCS retrofits. Harmonization of the Greenhouse Gas Reporting Program (EPA), National Emissions Inventory (EPA) and Emissions & Generation Resource Integrated Database (DOE) would materially reduce the efforts of would-be carbon capture developers to screen for ideal host facilities.

Theme 4: Streamline federal and state regulatory requirements across the CCS value chain of capture, transportation, sequestration, and long-term monitoring

CCS value chain complexity — aligning capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements — creates coordination costs and development risks that are disadvantageous to most developers, relative to other clean energy projects. Even highly experienced investors and specialty pools of funds that are otherwise quite willing to pursue "risky" projects shy away from CCS in large part because of value chain complexity.

The lack of permitted geologic storage sites, compounded by the prospect of building large-scale pipelines, creates "holdup" problems across multiple physical and regulatory landscapes for CCS that are distinct from other industries. These include: a lack of a clear permitting regime for interstate CO_2 pipelines (federal policy); uncertainty surrounding the ownership of pore space where injected CO_2 will ultimately reside (state regulation); challenges related to obtaining unitization of land/pore space (largely state regulation if not on federal land); length of time and related uncertainty regarding underground injection permitting (federal or state regulation); and the estimation and available funding approaches used for financial assurance necessary to support post-operation and post-closure injection site care (federal and state regulation).

Policy recommendations to reduce CCS value chain complexity

- State Governors should each create one empowered coordinating body to manage all state-level CCS regulatory interfaces including: facility siting, eminent domain, pore space unitization, long-term liability requirements, etc.
- State coordinating bodies and legislatures each need to develop clear, workable regulations and statutes concerning pore space unitization, post-closure liability, and pipeline eminent domain.
- Congress should take up the issue of the appropriate federal role in permitting, eminent domain, and economic regulation for interstate pipelines and geologic sequestration sites.
- Congress should consider authorizing innovative public private partnerships (including federal ownership stakes) in FOAK CCS pipeline and sequestration infrastructure to the extent so doing facilitates the construction of larger and less costly subsequent developments.

Theme 5: Siting analysis for a carbon capture project needs to address fenceline community health issues

Current permitting approaches, and the attendant public disclosure processes, for carbon capture projects have been built on legacy assessment systems and precedents that apparently lack the flexibility and transparency needed for simultaneously scaling up CCS nationally, protecting human health, and maintaining air quality standards. Especially in the case of retrofits that append carbon capture capabilities to existing facilities, the current framework can lead to limited disclosure of environmental benefits and/or detriments, undermining the social license to operate such capture projects.

Under current regulations, a carbon capture developer is typically motivated to analyze and permit a carbon capture installation in isolation from the CO_2-emitting host facility, because the developer wishes to avoid "reopening" currently applicable air emissions permits at the host facility. In many cases CCS installations provide non-CO_2 environmental benefits to the host facility such as mitigating some criteria pollutants (including common smog and acid-rain precursors) by pre-treatment of flue gases. Yet when the carbon capture is permitted as a standalone project, these non-CO_2 benefits are not adequately considered or disclosed in the permitting process.

There is inherent tension in the current system. On the one hand, expanding the entire air permitting process for new carbon capture retrofit projects to consider the host plant would trigger additional regulatory requirements under EPA air permitting rules that could pose delays, raise other non-CCS issues, and potentially jeopardize the project entirely. On the other hand, not considering the entire system could lead to an incomplete assessment of environmental impacts disclosed to the public.

Policy recommendations for carbon capture project emissions disclosure/research

- State environmental quality authorities should require carbon capture project proponents to perform and comprehensively disclose an analysis of the combined impact on emissions of CO_2, criteria air pollutants (CAP), and hazardous air pollutants (HAP) of the host facility and the new capture plant. This would be a community disclosure requirement, not a change in the actual Clean Air Act-based permitting regime that EPA generally has delegated to individual state air quality authorities.

- The Department of Energy should fund and undertake research examining the net changes of CAP and HAP that result from carbon capture installation, particularly in industries characterized by host facilities that produce both high quantities of CO_2 and conventional pollutants.

Theme 6: Harness community benefits given the energy transition

Building CCS infrastructure can preserve existing jobs and the economic base within a community (e.g., continuing the operation of an existing cement plant), while also providing new opportunities (e.g., building and operating a carbon capture installation adjacent to a host cement plant). These benefits may manifest all along the value chain, where the need for new infrastructure (e.g., pipelines and geologic sequestration sites) may create new economic benefits.

How the labor force will grow and what specific benefits will accrue to the groups proximate to CCS development can be shaped by constructive negotiations between communities, their leaders, and CCS developers. Community engagement by developers offers the chance to design outcomes to accommodate preferences expressed by those who have a stake in the project. This approach where communities have agency and efficacy in the process, also benefits developers by gaining a social license to operate. The appropriation of benefits afforded to both parties — the developer and the community – can be formalized within a community benefits agreement (CBA), which, in turn, acts as an enduring basis for continual engagement across all phases of the project.

Policy recommendations for sharing community benefits

- The Department of Energy, working with states and local governments, should provide direct funding for the capacity building of communities to lead the negotiation of CBA with CCS developers.

CONCLUSION

Turning CCS projects into blue chip investments: A suite of mutually reinforcing recommendations

The recommendations associated with the themes ought to be viewed as mutually reinforcing in enhancing the investment quality of CCS as a decarbonization solution. It is the totality of the recommendations that can materially lower the barriers to private flows of capital to CCS projects. Taken together, these recommended policy actions would address the investment challenges faced by project owners, developers and investors, meaningfully supporting the at-scale deployment of CCS as an industry within a portfolio of solutions needed to reach U.S. decarbonization goals.

Turning CCS projects in heavy industry & power into blue chip financial investments

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INTRODUCTION

The United States has complementary goals of 50-52% CO_2 emissions reduction from 2005 levels by 2030 and net-zero emissions by 2050. To carry out these goals requires an immense mobilization of resources, private capital, and innovation to support accelerated scale-up of current technologies (e.g., solar and wind energy, vehicle electrification, etc.) and emerging solutions. Carbon capture and sequestration (CCS) – capturing point source emissions and permanently storing them in geologic formations – is a critical component within a portfolio of decarbonization solutions. CCS can materially reduce the overall cost of achieving U.S. decarbonization goals while mitigating several hundred million metric tons of emissions per year. It can be deployed across various power and industrial applications, helping multiple sectors support the overall decarbonization mission.[a] CCS can enable negative emissions via bioenergy with carbon capture and storage and help jumpstart the low-carbon hydrogen economy. CCS can deploy a talented workforce to a growth industry (carbon management) and leverage existing infrastructure and expertise in creating new economic opportunities on the order of tens of billions of dollars per year in incremental investment. However, it will take concerted policy action – building on existing momentum – to make these promises a reality.

Several variants of carbon capture are well-established and already in commercial use across such industries as natural gas processing, urea production, and petrochemical production from coal gasification. In the U.S., thousands of miles of oilfield-serving pipelines transport CO_2 to be injected underground for enhanced oil production. The CCS value chain's essential elements – capture, transport, deep underground injection, and ongoing monitoring – have been deployed in various commercial applications in the U.S. for decades. A critical means for greatly reducing CO_2 emissions from fossil fuel combustion and industrial processes, the CCS value chain should now be configured and

[a] The focus of this study is on carbon capture as a pollution control technology used primarily to reduce GHG emissions on new and existing point sources such as power and industrial facilities. Note that upstream GHG emissions (e.g., methane leaks in natural gas production, transmission, and distribution systems), if not adequately addressed, can offset these system lifecycle emission abatement efforts. Discussion of proposals and efforts to inhibit such upstream emissions (e.g., tied to natural gas, coal, chemicals, etc.), while crucial for decarbonization efforts, are outside the scope of this work.

deployed as a cohesive decarbonization solution, an essential piece in pollution control technology.

Estimated capture costs (first builds and projections for commercially mature solutions) and annual emissions (CO_2e) for sectors in the U.S. where CCS is technologically compatible as a pollution control technology are shown in **Figure 1a**. With total emissions of approximately 1,900 million metric tons of CO_2 (**Figure 1b**), the industries represented in the figures below represent 73% of U.S. industrial and electricity sector emissions and 36% of all emissions nationwide. It is important to note that many of the facilities in these sectors are relatively young, with decades of operation still ahead of them. For example, while the capacity-weighted average age of coal power plants is 42.3 years, 22 GW of new coal-fired generation capacity has been built since 2000. NGCC generation facilities have a capacity-weighted average age of only 17.2 years, with 80 GW of capacity built since 2012.[1] Cement plants, based on clinker capacity, have a capacity-weighted average age of 27.4 years, with 54% of capacity built after 2000, 68% of which uses coal as the primary fuel source.[2]

Figure 1a

By industry comparison of calculated First-of-a-kind (FOAK) & Nth-of-a-kind (NOAK) $/metric ton cost of CCS to the Inflation Reduction Act tax credit incentive

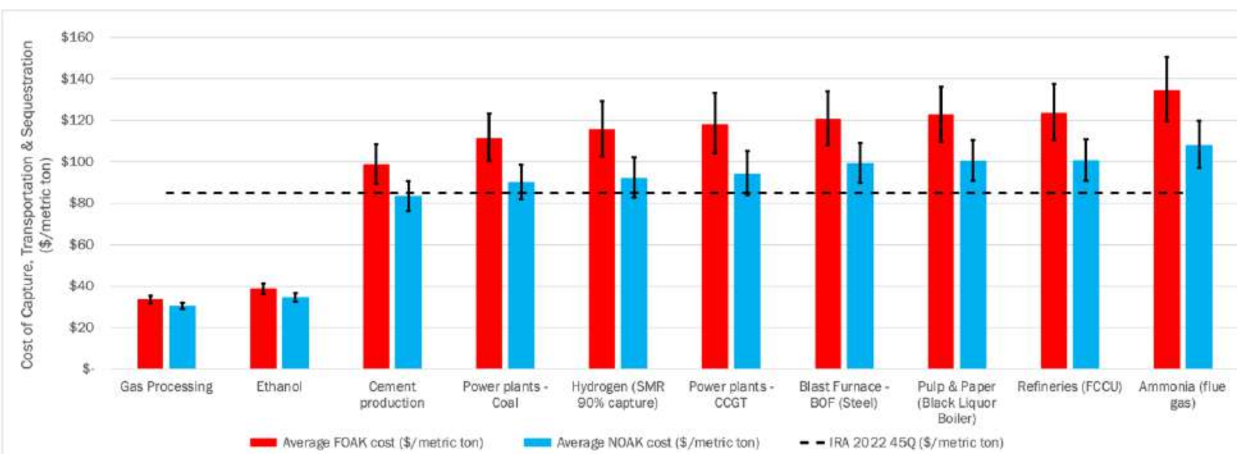
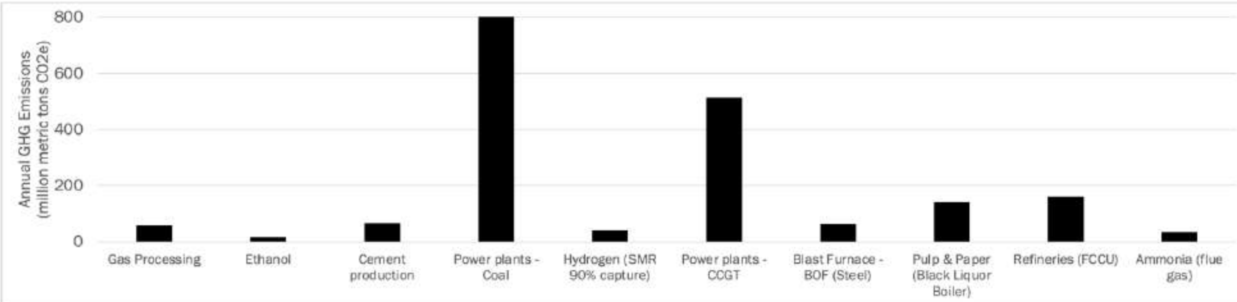


Figure 1b

By industry comparison of annual (2021) GHG emissions in million metric tons of CO2e



Displayed cost estimates are in 2022 dollars and include $15/metric ton transportation and sequestration costs (both FOAK and NOAK). The variance on each cost estimate represents the range of cost increases on a generic chemical processing facility due to inflation from 2018[b] using the Chemical Engineering Plant Cost Index (CEPCI).[3] The low range reflects a 16% increase (index reading from 603.1 in 2018 to 701.4 in June 2021); the high range is 38% (from 603.1 to 832.6 in June 2022). Each average cost (column) is the midpoint between these two inflation-inclusive estimates. See the Appendix C for more detail. The emissions graphed here are not total U.S. GHG emissions; Fig. 1b includes only emissions data reported by large emitters to the Greenhouse Gas Reporting Program (GHGRP) in 2020. Data from EPA FLIGHT.

CCS as a pollution control technology can have a substantive decarbonization role to play going forward since many of the plants are relatively new, and any unabated emissions of these plants are significant; the need for their products (power, cement, steel, fertilizer) is robust, and all are considered essential building blocks of an advanced economy.

Suppose significant fossil fuel combusting equipment remains operative in future decades. In that case, the GHG emissions of such facilities must at least be abated with an “end of pipe” solution such as CCS. In the electricity sector, coal generation has fallen and is often replaced by natural gas and renewables. However, half of today’s 200GW of coal capacity will likely remain online, running at reasonably high-capacity rates (i.e., 50-60%) for decades to come. [c,4,5,6,] Those facilities that are not slated for retirement soon will need to be retrofitted to mitigate their emissions until replacements are made.

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[b] The year 2018 is the most recent reference date for such reports as the U.S. Department of Energy National Energy Technology Laboratory Baseline Studies for Fossil Energy Plants and the National Petroleum Council Report “Meeting the Dual Challenge” both published in 2019 and represent a significant portion of the cost modeling used in this report.

[c] EIA’s Annual Energy Outlook 2022, Table 9 (Electric Generating Capacity) Reference Case shows the existing ~200GW of coal capacity declining to 121GW by 2030, but with 106GW still remaining in 2040

In a similar vein, despite significant growth in renewable electricity and stationary storage, natural gas generation, which provides essential load following and firming capacity for renewables, provides the highest percentage of power generation in the U.S. fleet. Further, the Energy Information Administration's (EIA) reference case projects that by 2040 natural gas will have 33% market share of total net electric power sector generation. And carbon emissions from these facilities also need to be mitigated.

The industrial subsectors, including cement, steel, ammonia, and hydrogen production, whose production facilities do not face the same level of substitutive competition relative to fossil fuel electricity generation, will likewise require emissions mitigation. There will be an ongoing need to mitigate GHG emissions from the existing stock of industrial assets to meet decarbonization goals. Absent other technologies to provide carbon-free high-quality process heat for critical industrial needs, CCS will be needed at scale.

The unfulfilled promise of U.S. scale-up of CCS

Despite existing capabilities, CCS progress to date as a decarbonization solution in the U.S. has been disappointing. A fundamental reason for this is simple: CO_2 emissions are not restricted or priced at the national level. If such requirements existed with a sufficiently stiff cost – as, for example, is the case for pollution discharges into water or sulfur emissions into the air – then there would be a clear commercial impetus to avoid such penalties by reducing emissions via deployment of CCS. Clearly, a significant CO_2 emissions price would dramatically enhance the case for CCS, but such a price is not anticipated in the U.S. anytime soon.

CCS is one of many decarbonization technologies that offer promise but have been slow to deploy in the United States. Despite years of development, technological advancement, policy progress and availability of federal incentives, CCS has thus far failed to deliver on its promise as a viable electricity and industrial sector pollution control technology. Why?

The poor economics (expected, not demonstrated), coupled with incomplete and/or counterproductive regulatory burdens, have discouraged many parties from project development efforts. Moreover, those who have invested in development efforts have had great difficulty attracting third party capital, or in the case of large corporations, in obtaining internal authorizations for investment.

A description of the overall failure of deploying CCS at scale to meet climate change mitigation goals is captured succinctly in *The Economist:*[7]

> *"Since the turn of the century CCS has been held up as a way in which coal and gas could go on being used to generate electricity without wrecking the climate, both by being retrofitted to existing plants and designed into new ones. The degree to which this has failed to happen is spectacular. The IEA's Net-Zero Emissions scenario calls for CCS in electricity generating plants to be capturing 430 [million metric tons] of CO_2 a year by 2050. The only commercial power station in the world currently using the technology captures 1 [million metric tons] a year. And it runs on coal. There is not a single operational CCGT fitted with CCS."*

This description of lack of progress stands in contrast with the potential benefits of CCS:

- It is the principal technology for separating CO_2 from a mixed gas flow is ubiquitous world-wide in industrial applications such as natural gas processing, urea manufacturing, and coal-to-hydrogen.[d,e,8]
- In terms of other parts of the value chain pipelines and subsurface injection, the U.S. is estimated to have 5,150 miles of dedicated CO_2 pipelines;[9] and U.S. firms have injected (and retained in the subsurface) on the order of one billion metric tons of CO_2 historically through enhanced oil recovery (EOR) practices, with a current injection rate of ~68 million metric tons of CO_2 per year.[10]
- The UN International Panel on Climate Change has stated that costs of achieving climate goals could more than double if CCS is not fully utilized.[11]
- CCS offers a clear route to decarbonization of existing industrial plants that are, in the intermediate term, an irreplaceable part of the U.S. industrial and employment base.[12,13]
- CCS is flexible since carbon capture systems can be used either as an end-of-pipe solution to directly abate GHGs in waste gas stacks, or as a means of extracting GHGs upstream in the manufacture of gaseous and liquid zero-carbon fuels (e.g., hydrogen production via methane reforming with carbon capture).
- Adding CCS to existing carbon-intensive power and industrial plants often requires extensive pretreatment of exhaust to remove sulfur oxide (SO_x) particulates and

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[d] Figures on gasification plants using carbon capture, typically the Selexol or Rectisol solvent processes, are difficult to come by, in part because the bulk of the industry is in China. The figure cited is an EPA estimate as of 2016, with the power-based gasification plants stripped out, since coal-to-electricity gasification typically does not need to utilized carbon capture.

[e] Note that the CO_2 is captured in these plants, however, it is almost always vented to the atmosphere for lack of any reason to undergo the expense of sequestration. Two U.S. gasification plants that send the captured CO2 to geologic injection sites are the Dakota Gasification plant and the Coffeyville, KS petroleum coke gasification project.

nitrogen dioxide (NO_2), thus creating potential reductions in these conventional criteria air pollutants (CAPs). Such action would materially benefit fenceline communities, especially in non-attainment airsheds. Note that current reductions are made solely to assist the proper functioning of the capture equipment, not to meet air pollution regulations: the existing facilities typically have vintage permits that are still valid, allowing the existing facilities to emit CAPs at levels that would not be permitted in a newly built facility today.

The business model for CCS as a pollution control technology

Trying to explain the paradox regarding CCS's lack of progress in scale-up for pollution control brings to mind an old business adage: "follow the money." But in the case of CCS there has been no money path to follow. In fact, CCS is sometimes criticized for lacking a viable business model and for being over-reliant upon government incentives.

It is important to recall that there were no preexisting business models for wastewater treatment facilities or a coal-fired power plant flue gas desulfurization systems, in the absence of such policies as the Clean Water Act, the Safe Drinking Water Act, and the Clean Air Act. Today, despite these beneficial precedents of effective regulations on conventional pollutants, there remains no national regulated limit on CO_2 emissions, nor any monetary price to pay for its emissions.

Cleaning up effluent entering America's rivers and reducing sulfur dioxide that caused acid rain and severely impacted lakes, both these programs involved decades of debate, federal regulation, incentives, and economic support. The development and deployment of pollution control technologies to address water effluent and emissions of SO_2 into the air were the result of policy decisions that required the clean-up of such wastes, as part of the social license to operate the facilities that created the pollution in the first place. In contrast, legal requirements for facilities and their owners for CO_2 emissions currently do not exist in the U.S. at the federal level.

Again, in the absence of a carbon tax or emissions control compliance regime, nothing at the federal level forces a U.S. steel mill or coal power plant to scrub CO_2 from coal combustion-derived flue gases. Thus the U.S. has never had a commercial steel mill carbon capture project. Unlike other pollution control industries, such as solid waste (~$200 billion enterprise value) or municipal water supply and sewage treatment (~$300 billion bonds outstanding), there is little general demand for CCS as a pollution control option.[f,g] As there are no current forcing mechanisms compelling emitters to repurpose industrial CO_2 removal technologies to pollution control applications, the world has very little practical experience with pollution-control use of CCS across power and heavy industry. There has been only a single coal power plant post-combustion CCS project, and that one was abandoned in 2020 when oil prices critical to the project's success fell from over $100 to below $40 per barrel.[14]

The key challenges of redeploying CCS as pollution control technology

Without "sticks," the policy of "carrots" for accelerating the development and deployment of CCS as a decarbonization technology must be generous enough to attract the necessary private capital. However, until very recently, and in only specific cases, the federal support mechanisms of corporate income tax credits – offered on a per metric ton of CO_2 sequestered basis – have not been large enough to cover the capital and operating costs of CCS, especially when given the challenges associated with first-of-a-kind deployments. Importantly, to kick-start at-scale investment in CCS as a decarbonization solution there are two fundamental challenges that need to be addressed: application heterogeneity and value chain complexity.

Application heterogeneity refers to the deployment of CO_2 capture technologies in new industrial settings. Current carbon capture technologies have been engineered and optimized for specific flue gas characteristics such as temperature, pressure, CO_2 concentration and the presence of other chemicals and impurities. While there is considerable expertise and experience in these settings, the same cannot be said for the variety of retrofit scenarios across industrial and power sector applications – settings for which carbon capture is key to materially reducing emissions. Excessive optimism based on carbon capture in industry has led to incorrect assumptions about how easy it will be to scale-up of CCS as a broadly applicable pollution control technology. In fact, it will take effort to tune carbon capture to each new heterogeneous application, and progress in one setting may not translate seamlessly to another. Each new application of carbon capture is a first-of-a-kind; to drive down costs and build up commercial confidence in each

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[f] $193 billion combined latest enterprise values (market value of equity plus long-term debt outstanding) of the three largest U.S. solid waste management companies, WN, RSG, and WCN reported by Yahoo Finance August 5, 2022.

[g] Estimate: $4 trillion outstanding, with approximately 11% issued for non-power utilities. Detailed market data are proprietary and expensive to obtain. https://www.msrb.org/Market-Topics/~/media/6C4DDF98D4074C83AECD80A2DA5C93B2.ashx

commercial setting, the innovation of multiple applications needs to occur in parallel. Moreover, a business model for CCS as a pollution control technology must consider and accommodate the needs of different industries, as the application of a given incentive may have a different effect on economic viability in one industry compared to another.

Value chain complexity refers to the four links that connect a CO_2 capturing industrial facility to permanent geologic storage: capture, transport, deep underground injection, and ongoing monitoring. Each of these four value chain links are industries onto themselves, much like the oil sector is divided into exploration, production, midstream, refining and distribution subsectors. As such, CCS is a complex decarbonization solution that requires integration across markets, technologies, and geographies to be functional. Moreover, each of the four CCS links are currently regulated relatively independently from each other, with little coordination across federal, state, and local agencies. Taken together, the nascency of CCS economic, infrastructure, and regulatory regimes effectively saddles potential developers with a multitude of risks for each of the four links in the value chain. The complexity and compounding financial risk attendant to managing these four links simultaneously makes CCS a distinctly challenging decarbonization solution.

On a risk-adjusted basis, even in the presence of greater financial support mechanisms, CCS remains challenged relative to most other kinds of development when it comes to attracting investment capital. Given such conditions, now is a critical time to develop a coordinated, comprehensive, long-term set of incentives as well as improved market, permitting, and regulatory policies. All these are needed to attract billions of dollars of private sector financial capital and widen the application of CCS to key industries. Without private capital to leverage public investment, CCS will not scale up and a key solution will remain lacking, and by such postponement, drive up the overall cost of decarbonization.

CCS policy actions in the last half-decade in the United States

Over the last five years the U.S., Congress, and the Executive branch have taken actions to promote CCS investments by revising existing—or introducing new—policies. In 2018, the Section 45Q tax credit for CCS underwent a substantial reform, increasing the value of the credit to $35 and $50 per metric ton by 2026 for EOR and GS respectively, from its original (2008) baseline of $10 and $20 per metric ton. The 2020 Energy Act, as part of Consolidated Appropriations Act 2021 directed DOE to fund about $6 billion of CC(U)S

RD&D over the next five years, incorporating key provisions from the Utilizing Significant Emissions with Innovative Technologies (USE IT) Act. This law focuses on interagency efforts for planning, siting, and permitting of CO_2 transport and storage infrastructure.[15] In addition, the Bipartisan Infrastructure Law (BIL), passed in 2021, provides $12.1 billion of funding to carbon management over the next five years, including $2.54 billion for demonstration capture projects (§41004), $2.1 billion in low interest loans for shared transportation systems (§40304) and $2.5 billion in grant funding for large-scale sequestration projects (§40305).

Pursuant to the USE IT Act, the Council on Environmental Quality (CEQ) issued *Carbon Capture, Utilization, and Sequestration Guidance* for federal agencies in February 2022. The guidance was introduced to *"facilitate reviews associated with the deployment of CCUS and to promote the efficient, orderly, and responsible development and permitting of CCUS projects,"* including: recommendations for federal agencies on developing programmatic environmental reviews, establishing a facilitating agency for each CCS project category in the Federal Permitting Infrastructure Permitting Council, and performance schedules for each category of CCS project; undertaking measures to facilitate a transparent process and meaningful public engagement; collaborating on studies of environmental impacts of CCS; and sharing information, best practices, and methodologies on data collection and reporting.[16]

The passage of BIL and CEQ's guidance on CCS paves the way to scale up investments in CCS by materially addressing most regulatory and infrastructure risks as well as reputation risks. On the latter, for example, DOE's carbon capture demonstration projects program funded by BIL will require the applicants to submit a community benefits plan related to community and labor engagement, investing in the American workforce, diversity, equity, and inclusion and accessibility, and the administration's Justice40 Initiative for community-informed CCS demonstration.[17] Provisions on public engagement and providing communities with forums to shape CCS projects in the early phases of projects will also help mitigate the reputational risks associated with CCS.

In June 2022, the *West Virginia v. EPA* ruling by the U.S. Supreme Court (SCOTUS) struck down the Clean Power Plan (an Obama Administration regulation that was never implemented, limiting GHG from existing power plants), effectively limiting a regulatory approach that could have been used by the EPA. The Court ruled that the EPA does not have the authority to set emissions limits based on "generation shifting" (i.e., shift from higher-emitting to lower- or zero-emitting sources in power generation).[18] As a result, to set standards for limiting emissions in power plants, EPA will have to rely on only "source specific" mechanisms that regulate emissions at the source, reflecting a narrower interpretation by the SCOTUS. Source specific mechanisms include efficiency (i.e., heat rate) improvements, fuel blending, and CCS.

Despite the ruling, CCS remains the only current option that could enable large-scale emissions reduction from existing fossil fuel fired power generation. The cause of this uncertainty: EPA must determine if CCS as the best system of emissions reduction (BSER), a designation that can only be made for adequately demonstrated technologies. Since there are mixed views on whether CCS is demonstrated technology, it may be difficult to determine CCS as the BSER, at least in the very near future.[19] Moreover, states retain the flexibility to determine how they will achieve EPA's targets, including using generation shifting as a strategy for emissions reduction. The impact of this ruling on accelerating CCS deployment is not yet clear. Importantly, however, the ruling did not affect EPA's general authority to regulate CO_2 emissions under the Clean Air Act.

The Inflation Reduction Act (IRA), signed into law in mid-August 2022, provides an enhanced tax credit value of $85 per metric ton. The IRA also makes considerable improvements to the usability of 45Q, specifically the direct pay and transferability provisions. This CCS focused tax credit is eligible for "direct pay" provisions for the first five years of the incentive for (tax-paying) private parties, followed by seven years of enhanced transferability for corporate taxpayers. Tax-exempt entities such as governmental, cooperative, and tribal owners of CCS projects can now use direct pay provisions for all 12 years of claiming the credits.[20]

The IRA significantly mitigates a portion of CCS commercialization and revenue risks through supply-side support mechanisms. For example, CCS applied to gas processing and ethanol are clearly economic given the tax credit value (see **Figure 1a** and **Table 1** above), while cement production retrofits may be borderline-feasible for FOAK projects. The IRA also expands the existing DOE loan program (§1703) that includes the "Advanced Fossil Loan Program" by $40 billion of loan authorization plus a $3.6 billion appropriation for program costs, including credit subsidy costs. In addition, the IRA adds an entirely new section "1706 program" the Energy Infrastructure Reinvestment Program, supporting $250 billion of loan authorizations, plus a $5 billion appropriation for credit subsidy costs. The 1706 program could, through provisions aimed at revitalizing existing energy infrastructure, provide flexible loans for carbon capture projects.[21] Finally, IRA appropriates $5.8 billion to provide grants for advanced industrial technologies, including carbon capture.[h,22] Early projections of the total quantity of CO_2 that could be captured and sequestered across point sources is 200 million metric tons per year in the U.S. by 2030, rising to 450 million metric tons by 2035, which will require hundreds of billions of dollars of capital expenditures to accomplish (see **Box 1**).[23]

Box 1

What is the magnitude of potential capital expenditures for CCS assets?

Total current and projected clean energy capital expenditure needs: according to BNEF, $114 billion of clean energy investments was made in the U.S. in 2021.[24] This includes all investments in renewable energy, energy storage, electrified transport, electrified heat, hydrogen production, CCS, and sustainable materials. According to initial estimates by Princeton NET ZERO lab, with the passage of the IRA on top of the BIL, this annual value could grow to $400 billion by 2030. With this order of magnitude in mind, it is useful to estimate the total capital expenditure required to scale up CCS in the U.S. to a 100 million metric ton/year industry.

CCS capital cost per annual metric ton captured & stored: a general estimate is ~$565 of capital cost per metric ton of annual system capacity for CO2 to be captured, transported, and sequestered, based on a system that can operate for 30 years. This estimate of $565 per annual metric ton of system capacity is based on:

1. Cost of capture equipment: $350 per metric ton captured (assumed average value across types of application by industry)
2. Cost of gathering pipelines: $25 per metric ton captured[i]
3. Cost of trunk lines: $40 per metric ton captured[j]
4. Cost of storage facility: $150 per metric ton captured[k]

Implications for total CCS capex spending: The $565/metric ton per year translates to ~$56.5 billion capex per 100 million metric tons/year of capture capacity. An estimate of national capture capacity needed is available from the Princeton NET ZERO lab, which estimated that the combined impact of the IRA and the BIL could spark capture of 200 million metric ton/year by 2030 an incremental 250 million metric ton/year by 2035.25 Using the $565/metric ton-yr. capacity cost estimate, these captured volumes would imply total CCS capital spending of $14.1 billion/yr. between 2023-2030 (inclusive), and $28.3 billion/yr. between 2031-2035 (inclusive), for a total of about $250 billion from 2023-2035.

[h] See Section 50161 of IRA for the $5.8 billion number. The purposes are cross referenced to 42 USC 17113(c).

[i] 100 million metric tons/yr, split across 50, 1-mile spur lines, each with average capacity 2 million metric tons/ yr; each pipeline costs $50 million, therefore the total cost is = $2.5 billion or $25/metric ton captured

[j] 100 million metric tons/yr, split across 10, 200-mile trunk lines, each with average capacity of 10 million metric tons/yr; each pipeline costs $400 million, therefore the total cost is = $4 billion or $40/metric ton captured

[k] $150/metric ton/yr of injection capital cost as estimated by NETL. Therefore, total cost is $15 billion, or $150/metric ton captured

Much has been done, but more is needed for CCS to scale

In the past five years, significant progress has been made in accelerating the development of a CCS industry through a series of complementary federal and state regulatory and legislative actions. This has markedly improved the development of a few targeted projects, such as ethanol and gas processing. Yet, the CCS industry has been proceeding by fits and starts, without a comprehensive plan for success. Clearly, a coordinated, comprehensive, long-term set of (supply-side) incentives and complementary (demand-side) market, and federal and state regulatory policies are required to attract billions of dollars of private sector financial capital to pioneer the application of CCS to a dozen key industries. Without private capital to leverage public investment CCS will not scale up, and the ability to mitigate (and remove) emissions from key industries will be substantially diminished. To be clear, the BIL and IRA specifically have provided tailwinds to the commercialization of CCS. However, to meet both immediate and long term decarbonization goals, additional congressional, regulatory, and administrative actions are needed to accelerate the deployment of CCS as a pollution control technology across the electricity and industrial sectors.

This study identifies six broad themes regarding the investment challenges for CCS that are consistently raised by project owners, developers, and investors. These themes are related to a mix of supply- and demand-side issues (Theme 1 and 2); informational and industrial coordination barriers (Theme 3 and 4); and environmental and economic justice concerns (Theme 5 and 6). The subsequent chapters of this report offer policy recommendations to address the challenges described in each theme to attract the private capital necessary to scale up CCS as a decarbonization solution.

FINDINGS: SIX THEMES FOR IMPROVING ATTRACTIVENESS OF FINANCING CCS AS A POLLUTION CONTROL TECHNOLOGY

Analyzing findings from commissioned whitepapers, stakeholder interviews, technical workshops, and other primary and secondary research, six themes emerged regarding the investment quality challenges for CCS. These themes continually re-emerge for project developers, investors, lenders, corporate owners, and technology vendors.

Theme 1: There must be light at the end of the deployment tunnel – supply & demand incentives

Application heterogeneity coupled with value chain complexity requires CCS developers and investors to develop several interdependent, new industries *de novo*. These commercial entities – including technology providers, constructors, emitting facility owners, investors, and lenders – must see a clear, long-term, durable trajectory of policy support mechanisms driving CCS applications from early commercialization ventures to routine deployment. Essentially, capital providers of all risk appetites will not take the "first steps into the deployment tunnel if they cannot see light at the end of it." Put another way, there needs to be a trajectory of supportive policies to initiate the new industry and sustain it, to help ensure its role in deep decarbonization for both the power and industrial sectors. If the prospects of such a successful trajectory are weak, these entities will not see a commercial rationale for deploying the financial and human resources needed to develop CCS.

Deployment and commercialization policies for the first generation of projects must clearly segue into long-term base levels of support for the second generation, with both stages of incentives being locked into an initial unified policy. The unified policy should include federal support for the first-generation cohort of projects until there is a clear track record of commercial success for which costs have been driven down substantially. These first-of-a-kind (FOAK) and next-of-a-kind (NXOAK) projects, typically on the order of three to six builds per application, develop experience, knowledge bases and initial industrial coordination that will lead to commercially ready design and track records (second generation), known as nth-of-a-kind (NOAK). Further, the supporting CCS policy should also include long-term post-commercialization baseline federal incentives attractive enough – by themselves – for mature projects to be viable once NOAK cost levels have been achieved.

Of course, incentives that offset the cost of building and operating CCS as a pollution control technology must be revisited if and when a national policy to materially price or cap CO_2 emissions is implemented. While at the present time such mechanisms that directly limit CO_2 emissions (rather than indirectly by incentivizing the technology to capture it) appear to be politically infeasible, such policies do lend themselves to a higher level of investor confidence compared to various tax incentives. This is likely to be the case, however, only if an emissions cap is permanent and declining, or the emissions price is permanent and rising.

Theme 2: Tax credits need to become more efficient and accessible

The passage of the IRA will lead to an expansion of the clean energy corporate income tax credit market from ~$10 billion per year (2021 and 2022, measured in terms of cost to the Treasury in forgone tax revenue) to ~$34 billion per year in 2031 (for all energy related corporate income tax credits, including the 45Q CCS tax-credit). Moreover, the IRA has also made considerable improvements to the usability of 45Q, specifically the direct pay and transferability provisions. This CCS focused tax credit is eligible for “direct pay” provisions for the first five years of incentive for (tax-paying) private parties, followed by seven years of enhanced transferability for corporate taxpayers. Tax-exempt entities such as governmental, cooperative, and tribal owners of CCS projects can now use direct pay provisions for all 12 years of claiming these credits. Key proposed benefits of direct pay include: its simplicity (refund of cash issued as part of a corporate tax return) and value certainty (100 cents on the dollar provided all reporting requirements are satisfactory and true). A crucial intended benefit of transferability is the ability to allow developers who earn tax credits to transfer them to another party in exchange for cash, should they deem doing so as beneficial. Taken together, these provisions promise an increased value of 45Q to developers while expanding the market of would-be consumers of tax credits.

Despite these useful changes, it may be a challenge even for carbon capture projects that earn tax credits and smoothly monetize those credits. As a practical matter, the number of tax-paying entities that possess both a natural business nexus to CCS (such as those in heavy industry, energy, or electric generation) and have large enough tax liabilities to utilize CCS tax credits is limited. The current pool of tax credit consumers has limited capacity to monetize additional credits, given a combination of relatively low corporate tax rates and the longstanding federal limitations on a corporation's pre-credit federal tax liabilities that can be offset using corporate tax credits. All the more vital it is to attract new participants who will make use of ("monetize") transferred tax credits, thereby creating new sources of financial capital for CCS project. This should be a first-order priority of policymakers.

Further, CCS tax credits are not as certain as a solar investment tax credit: if a solar project goes into service and the project does not change ownership for five years, the solar tax credit will not be "recaptured" or subject to return by the Internal Revenue Service (IRS). If wind generated electricity is produced and fed into the grid, the associated production tax credit (PTC) is also considered "absolutely safe." In contrast, the 45Q credit is viewed less favorably by potential investors because of the complexity of the CCS value chain and the possibility of losing the tax credit. This may occur when the injector of captured CO_2 (such as a 3rd party commercial geologic sequestration site) fails to comply with Environmental Protection Agency (EPA) regulations, fails to file the proper paperwork with the IRS, allows leakage, or goes bankrupt. As such, the 45Q tax credits have historically been of little direct use to CCS projects, and only of modest interest to a few large corporations and tax equity partners. Drafting workable IRS implementing regulations, a process that has begun only recently, is critical to capitalizing on this partial, but meaningful, progress.

Theme 3: Critical data and knowledge exist on capture and geologic storage; increasing its availability and accessibility can accelerate commercialization

Detailed data and knowledge about carbon capture technology and geologic storage (GS) characterization has been created as part of federally funded programs. This is a rich and useful resource that could benefit would-be project developers and investors. Yet not all this information is readily accessible in a form that would-be CCS developers could use to inform critical investment and design decisions. This inaccessibility has resulted in a reduction in the pace of potential new solution development, as well as elevated costs across the value chain, as project designers, sponsors and regulators do not fully benefit from knowledge spillovers.

Many experts have been calling for greater transparency of data, experience, and knowledge generated by federally funded carbon capture technology projects.[26,27] Providers whose proprietary systems are being installed in federally funded projects (i.e., projects that benefit from federal "cost sharing agreements") ought to be able to protect and retain their private patents, intellectual property, and critical know-how. There needs to be a balance struck, however, between rewarding the federal grantee who has put resources at risk and supporting would-be follow-on developers who benefit by learning from first movers. The industry in general would greatly benefit from wider access to actual costs and operational data tied to federally funded carbon capture projects. Examples of operational data should include detailed system layout and system and key sub-system performance (including energy efficiency and emissions).

With respect to geologic sequestration (GS), the federal government has given grants to several projects that have performed extensive investigations for GS (e.g., the Southern Company/Kemper Project) or obtained EPA Underground Injection Class (UIC) VI permits and injected/sequestered (e.g., the ADM/Decatur Project). Original and continuing efforts have primarily focused on data acquisition, data curation and model-building for public and industrial R&D purposes. Expanded efforts are required to build the toolsets needed by multiple stakeholders, such as developers, local communities, and policymakers, to make informed decisions regarding GS commercialization. These data can be bolstered through aggregating similar and complementary resources collected by colleges, universities, and state geologic surveys. Further, while the volume, quality and structure of the data are important, translating such input into useable tools and formats that support commercial decision-making will accelerate GS facility deployment, while reducing development costs.

Taken together, there is enormous informational value that has been created through decades of federal funding that could be used to accelerate CCS development. To the extent that more information about first mover projects is made public in a timely manner and that the information is made useable for commercial purposes, all this would lower development costs and decrease site selection, construction, and future O&M risks. Lower risk, in turn, would translate into lower all-in cost of capture, which would then increase the rate at which new follow-on projects are deployed.

Theme 4: Streamline federal and state regulatory requirements across the CCS value chain of capture, transportation, sequestration, and long-term monitoring

CCS value chain complexity – aligning capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements – creates coordination costs and development risks that are disadvantageous to most developers, relative to other energy projects. Even highly experienced investors and specialty pools of funds that are otherwise quite willing to pursue "risky" projects shy away from CCS, in large part due to value chain complexity. Added to this, beyond the technical and organizational challenges of CCS is a complicated regulatory regime. Each of the four CCS links are currently regulated relatively independently from each other, with little coordination across federal, state, and local agencies.

There are also historical, financial, legal, structural, and regulatory reasons as to why the oil and gas industry is organized into distinct upstream, midstream, and downstream sectors. Each sector has corresponding specialists in the investment community; financial investors, lenders, credit, and equity analysts, and managers specialize in just one of these individual links of the value chain because, in part, garnering competence in any of these three sectors is a significant challenge.

By contrast, carbon capture developers are required to master upstream (capture), midstream (pipelines), downstream (geologic sequestration) as well as long-term monitoring links in the value chain. Individual "projects" must span all sectors, because of lack of adequate existing pipeline and storage infrastructure to support carbon capture scale up. At-scale deployment of pipelines and storage with federal support for FOAK facilities – coupled with state-level regulatory clarity – could lower development risks, operational risks, and business complexity. With such infrastructure development, a major GHG emitter could concentrate solely on implementing the carbon capture operation, and any uncertainties about transport and GS siting, for example, would not deter development.

Much as in the cases of rural electrification, the interstate highway system, and most recently, rural broadband access, the public sector has provided direction, guidance, and substantial resources to seed new industries, providing a foundation on which commercial developers could build.[28,29,30] The same is now required to grow the CCS industry at scale. Pipeline transportation, geologic storage and long-term site care are dimensions of large-scale carbon management where public involvement is needed by first movers. Specifically, by working together, federal and state governments can: (i) mitigate uncertainties related to permitting and pore space ownership; (ii) adopt a performance-based approach to financial responsibility for EPA Class VI wells; (iii) ensure scale economies; and (iv) ensure that transportation and sequestration infrastructure is designed to mitigate the market power of too few operators. Altogether these actions will significantly increase the investment case for CCS in the U.S.

Theme 5: Siting analysis for a carbon capture project needs to address fenceline community health issues

Current permitting approaches, and their attendant public disclosure processes, for carbon capture projects have been built on legacy assessment systems and precedents that apparently lack the flexibility and transparency needed for simultaneously scaling up CCS nationally, protecting human health, and maintaining air quality standards. Especially in the case of retrofits that append carbon capture capabilities to existing facilities, the current framework leads to limited disclosure of environmental benefits (and/or detriments), undermining the social license to operate such capture projects. Here's one reason why.

Under current regulations, a carbon capture developer is typically motivated to analyze and permit a carbon capture installation in isolation from the CO_2-emitting host facility. This is because the developer wishes to avoid "reopening" currently applicable air emissions permits at the host facility. And in many cases, CCS installations provide the host facility with non-CO_2 environmental benefits, such as mitigating some criteria pollutants (including common smog and acid-rain precursors) by pre-treatment of flue gases. Yet when carbon capture is permitted as a standalone project, these non-CO_2 benefits are not adequately considered or disclosed in the permitting process.

Further, there has been ongoing concern voiced by fenceline communities and their advocates that the emissions associated with the carbon capture equipment connected to the host facility will itself lead to incrementally more emissions of GHGs, criteria air pollutants (CAPs), and hazardous air pollutants (HAPs), negating the benefit of mitigated CO_2 emissions from the original vent stack. While the limited available data examined in this study suggests that there are indeed substantive benefits to carbon capture, it is completely understandable that fenceline communities remain skeptical, in view of the lack of publicly accessible research on the subject.

There is inherent tension in the current system. On the one hand, expanding the entire air permitting process for new carbon capture retrofit projects to consider the host plant will trigger additional regulatory requirements under EPA air permitting rules. This might pose delays, raise other non-CCS issues, and potentially jeopardize the project entirely. On the other hand, not considering the entire system could lead to an incomplete assessment of environmental impacts disclosed to the public.

To address this concern, concerted efforts by public entities are needed to support and promulgate detailed studies that examine and analyze the emissions consequences of the combined host and capture facility and make such studies useable to all stakeholders. This would help gain the needed social license to operate CCS as a pollution control technology.

Theme 6: Harness community benefits given the energy transition

Building CCS infrastructure can preserve existing jobs and the economic base within a community (e.g., continuing the operation of an existing cement plant), while also providing new opportunities (e.g., building and operating a carbon capture installation adjacent to a host cement plant). These benefits may manifest all along the value chain, where the need for new infrastructure (e.g., pipelines and geologic sequestration sites) may create new economic benefits.

While communities may indeed benefit economically from CCS projects, it is critical to remember that public opinion is formed by perceived risks and benefits (well-founded or otherwise) and is influenced by such factors as: project alignment with the community's long-term goals; the degree of trust in the project team and government agencies; and the perceived equity in the process of project development. Meaningful community engagement is needed to gain the social license to build and operate CCS projects as part of a broader decarbonization portfolio of solutions.

How the labor force will grow and what specific benefits will accrue to the groups proximate to CCS development can be shaped by constructive negotiations between communities, their leaders, and CCS developers. Community engagement by developers offers the chance to design outcomes to accommodate preferences expressed by those who have a stake in the project. Acquiring public acceptance may require extended consultation, discussion, and negotiation procedure with a range of local stakeholders.

This approach where communities have agency and efficacy in the process also benefits developers by gaining a social license to operate. Most capital providers consider environmental justice as they evaluate investments in energy transition infrastructure. Investors are increasingly screening projects for environmental and economic justice attributes as part of their due diligence process. Capital providers tend to be more motivated to participate in a project where good community engagement practices can be demonstrated and where local economic development can be broadly quantified and attributed to an investment.

THEME 1: THERE MUST BE LIGHT AT THE END OF THE DEPLOYMENT TUNNEL – SUPPLY & DEMAND INCENTIVES

Sufficient, stable, long-term revenues help build an enduring industry

Overview

A prudent explorer tries to avoid marching into a dark tunnel unless there is a glimmer of light visible at the far end. By the same token, major corporations, financial investors, technology providers, and construction contractors will not aggressively undertake a first-of-a-kind decarbonization project – or any multi-billion-dollar business venture – unless they can see a clear pathway leading to long-term success. As applied to CCS, a pollution control technology, a business line whose prospects are disproportionately driven by government commercialization programs and incentives (in the absence of compliance regimes) the “light at the end of the tunnel” is lit by strong federal policies – or extinguished by weak ones.

Carbon capture – the front end of the CCS value chain – requires many different, industry-specific, life cycle-appropriate deployment efforts. Carbon capture in each specific industrial setting needs to be nurtured by high-cost early projects, such as FOAK and NXOAK[I] which are the first through ~sixth installation for a given application, to lower-cost, later-stage nth-of-a-kind (NOAK) projects that will be fully feasible based on long-term policy support levels (scale-up projects). Fully understood and transparent, long-term policy certainty from the outset of a project is essential for building private sector

[I] See full explanation of FOAK, NXOAK, and NOAK acronyms in the following pages.

confidence sufficient to deploy resources to scale up from FOAK to NOAK across applications. The policy mechanisms that best support the trajectory from FOAK to NOAK is a mix of supply-side incentives (to lower the cost to developers to build carbon capture and gain experience), and demand-side incentives (to increase the potential for ongoing revenue for developers once the facility is operational).

Link to investability

Without the long-term assurance of a vibrant and growing market for CCS projects, the standardized components/sub-assemblies that the projects use, the engineers to build them, the infrastructure to support them, and the markets/incentives to pay for them, it is difficult to find lenders or investors for the first project.[m] This is true on the financial side of the ledger as well, in terms of decision-making by actors in the public capital markets of Wall Street and in the private, internal capital markets of corporate capital expenditure allocation.

These commercial parties will become interested in FOAK CCS projects if they can reasonably conclude that their FOAK efforts will yield them a subsequent competitive advantage, in turn leading to relatively higher market shares and profits compared to competitors. This will only be the case, however, if a viable market emerges with a reasonable “order book” for NXOAK and NOAK units. Without a viable market for future units, initial FOAK investors are trapped with an idiosyncratic asset (a so-called white elephant) with no likely secondary market buyers of either debt or equity. That situation raises the prospect that these early investors will not be able to exit the FOAK financial investment with their capital intact. In other words, there is currently a significant first-mover disadvantage for FOAK CCS projects.

Defining stages of commercialization for CCS

There are three deployment thresholds that connote increasing levels of system maturity on the road to full commercialization. Another way to view these categories is that FOAK and NXOAK (described in 1a and 1b below) together make up first-generation projects that need extra support beyond a baseline. NOAK projects, on the other hand, (2a below)

[m] Occasionally a one-off first project can be assembled, but costs tend to be prohibitive because every party involved treats the project as a one-off with no certain prospects of follow-on business. Specifically, the EPC contractor will seek to recover 100% of its engineering costs from the first project alone, and component suppliers will need to charge high prices to tool up to build one-of-a-kind parts and subassemblies.

are effectively second-generation projects that are feasible when relying on an existing baseline.

1. **First Generation: Driving costs down below long-term baseline support**
    a. First-of-a-Kind (FOAK) means "Serial Number 001" for a given design or industry application; and
    b. Next-of-a-Kind (NXOAK) includes the several projects (of a given industry application) that follow the FOAK (likely another 2-6 projects, for a total first generation of up to five projects) that are sufficient to: (i) eliminate investor concerns regarding technological failure; (ii) allow engineering, procurement, and construction (EPC) entities to offer reasonable, bankable commercial terms on lump-sum-turnkey (LSTK) construction contracts; and (iii) enable component/assembly suppliers to formulate manufacturing facility plans and designs for future scaled-up deployment.
2. **Second Generation: Driving widescale deployment**
    a. Nth-of-a-Kind (NOAK) includes those projects that are fully commercialized because of the experience gained through FOAK and NXOAK stages, with costs beginning to approach long-run trajectories given learning effects, supply chain establishment, and use of dedicated manufacturing capabilities.

FOAK, NXOAK, and NOAK stages of technology deployment must be considered simultaneously to ensure the proper formulation and implementation of policy support mechanisms. This consideration is required to build a durable trajectory and sufficient investor confidence to see a technology through to cost-effective implementation at scale.

Establishing CCS as a pollution control technology for an industry requires FOAK incentives to smoothly transition into long-term baseline incentives

Policymakers have traditionally thought about incentive programs for carbon capture at commercial scale in a manner divorced from the long-term baseline levels of the policy support required.[n] The challenge with this approach is that manufacturers, suppliers, vendors, developers, and financiers (i.e., the industry ecosystem) have no interest in doing a single project. These industry ecosystem actors are reluctant to invest the time,

[n] If there were other reliable demand side revenue sources, which there are not, those revenues would reduce the long-term support needed from federal incentives.

money, and internal resources required to finance, build, and operate project Serial #1 unless they can see a clear path to a sustained market. What is needed to raise private investor confidence is a suite of commercialization policies to cover NXOAK (commercialization) costs for CCS plants Serial # 2-6, and a trajectory of industry scale-up founded on baseline incentives generous enough to make feasible NOAK Serial #7-100.

Table 1 (below) shows the cost estimates for Serial # 1 (FOAK cohort of projects) and Serial #7 onward (NOAK) for various applications of CCS. The FOAK costs include relatively high estimates of capital recovery factors (13% of capital cost, based on a 12-year term)[o] and project contingencies (35-40% of capital cost)[p] that represent an experience level appropriate for deployment of a new technology. NOAK costs are reduced compared FOAK by using lower costs of an 11% capital recovery factor and 15-20% project contingency costs, indicating projected learning effects. Note that these estimates are comprehensive, including cost of capture/compression, cost of transportation, and cost of geologic sequestration.

Each estimate considers both a retrofit scenario and an inflation scenario. Note that these estimates are considerably higher than those of studies dating from 2018-2019 because of significant inflation in capital goods costs and higher natural gas/electricity costs.[q]

- The retrofit scenarios contemplate either low or high incremental capital costs experienced in brownfield/retrofit developments depending on the difficulty of physically integrating the capture project with the host emitter facility. A low estimate is based on a zero percent retrofit factor (multiplier) applied to the capital cost of the facility, meaning that no additional capital investment is required for the capture unit to be retrofitted to the host facility. The high estimate is based on a 15% retrofit factor.
- The inflation scenarios consider capital cost increases vs. 2018 of either 16% or 38% based on the Chemical Engineering Plant Cost Index (CEPCI) benchmark

[o] A capital recovery factor is a coefficient, expressed as a percentage of original project capital cost, that aggregates the annual fixed costs related to debt payments, returns of/on equity capital, and income taxes.

[p] "Contingencies" are the sum of extra funds to account for unusual risks that contractors build into their quoted price to deliver a completed project plus the extra funds lenders usually require that the owner supply to provide for unusual risks that are not otherwise borne by the contractors.

[q] A variety of U.S. Department of Energy studies used 2018-dollar cost bases, and several multi-industry cost studies were also completed in the 2018 period. Few multi-industry capture costs studies have been released since that timeframe. The two inflation scenarios provide a bridge from those old estimates to today, while realizing that construction indexes such as the CPI fall, as well as rise, depending upon market conditions.

increase from 2018 to June 2021 (low) or 2018 to June 2022 (high), respectively. Estimates are compared to the IRA promulgated credit rate of $85/metric ton; those highlighted in green are less than the tax credit value, and those in red are above it.

Gas processing and ethanol production seem to be, on average, economically viable at the IRA 45Q rate. At ~$90/metric ton, cement is nearly viable for FOAK given an ideal retrofit setting and low inflationary effects. All other applications suggest that additional support is needed to cover the cost gap between the 45Q incentive and the FOAK per metric cost of CCS to induce first builds and develop the knowledge and experience that could lead to the cost reductions reflected in the NOAK cost estimates.

Table 1

FOAK and NOAK total cost per industry, including retrofit and inflation scenarios, with comparison to IRA 45Q tax credit rate of $85/metric ton

	FOAK				NOAK			
Retrofit Scenario	Low		High		Low		High	
Inflation Scenario	Low	High	Low	High	Low	High	Low	High
Gas Processing	$31.69	$33.64	$33.25	$35.49	$29.05	$30.50	$30.21	$31.88
Ethanol	$36.20	$38.75	$38.25	$41.19	$32.78	$34.70	$34.32	$36.52
Cement	$89.47	$99.25	$97.31	$108.56	$76.39	$83.73	$82.27	$90.71
Pulverized Coal Power	$100.31	$112.12	$109.78	$123.37	$82.08	$90.48	$88.81	$98.47
Hydrogen (SMR 90% capture)	$102.68	$116.35	$113.64	$129.36	$82.69	$92.62	$90.65	$102.07
Natural Gas Power	$104.29	$118.98	$116.07	$132.95	$83.94	$94.82	$92.66	$105.17
Blast Furnace-BOF (Steel)	$108.15	$121.42	$118.79	$134.06	$89.75	$99.58	$97.64	$108.94
Black Liquor Boiler	$109.77	$123.35	$120.66	$136.27	$90.95	$101.01	$99.02	$110.58
Fluidized Catalytic Cracker	$110.40	$124.35	$121.58	$137.62	$90.83	$101.11	$99.08	$110.91
Ammonia (flue gas)	$119.52	$135.42	$132.27	$150.56	$97.01	$108.71	$106.39	$119.84

The IRA 45Q rate of $85/metric ton is compared equally across all sectors. Costs that are less than the $85/metric ton are highlighted in green; greater than $85/metric ton are highlighted in red. The NOAK capture costs are lower than FOAK capture costs due to learning and experience effects, expressed in terms of capital recovery factor and project contingency costs. Capital recovery factors, based on a 12-year term and MACRS 5-year depreciation are 13% for FOAK and 11% for NOAK 11%. FOAK contingency costs are 35-40% of capital cost; NOAK is 15-20%. For the retrofit scenario, "low" estimates are based on a 0% retrofit factor (multiplier) applied to the capital cost of the facility; the "high" estimates are based on a 15% retrofit factor. For the inflation scenario, the "low" estimate is based on a 16% cost of capacity increase (multiplier) from 2018 to June 2021; The "high" estimate is a 38% multiplier. Cost of capture also includes compression to pipeline pressures. A $15/metric ton cost for transportation and storage is included in all cost estimates. Refer to Appendix C for table of underlying data.

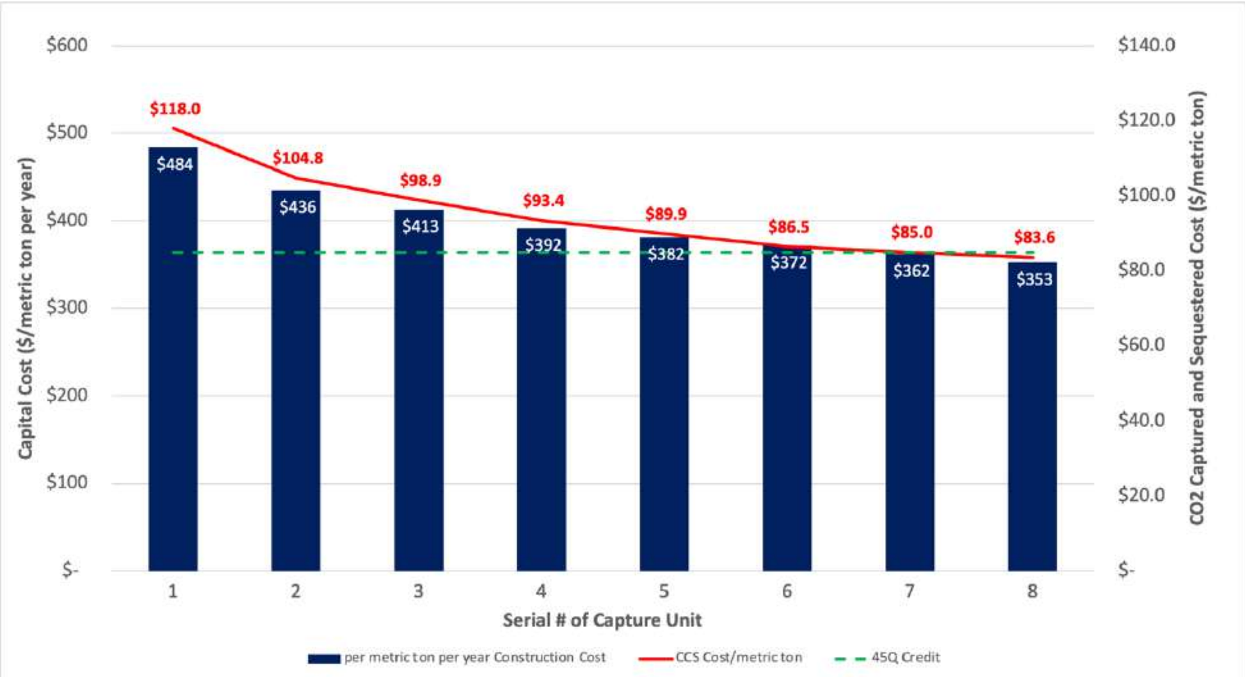
This incentive trajectory needs to be established and supported over a timeframe that is long enough for the various industry actors to execute their respective development plans. Historically, U.S. federal policy support in the carbon capture portion of CCS has focused on R&D; at most, only one instance of commercial deployment of a carbon capture system applied to an industry. There has been only one instance for each of federal grant-supported commercial deployment: (i) Mitsubishi Heavy Industries' post-combustion solvent-based carbon capture for a coal power plant (Petra Nova); and (ii) Air Products' vacuum swing adsorber capture system in hydrogen steam methane reforming.[31,32] Without the support to build multiple installations within a given industry, there is little hope of gaining significant cost savings from experience (learning) accumulation and supply chain improvements.

Learning-based cost reductions are seen in **Figure 2** which shows a projected 10% learning rate applied to a NGCC with CCS. The FOAK costs, coupled with the cost trajectory, shows that it is the seventh build in which expected levelized costs fall below the 45Q tax credit level (and thus becomes "in the money"). The "learning rate" is an empirical measure that refers to the overall cost decline derived from factors such as work force experience, raw material utilization efficiencies, production line flow improvements, etc.) as an industry's cumulative historical production volume of a complex product grows. In the formulation used here, a "10% learning rate" means that every time cumulative volume doubles, costs drop 10%.

The program of commercialization support for the FOAK/NXOAK projects must also segue smoothly into a program of baseline support that is locked in today over a timeframe relevant to the construction and operation of NOAK projects. This would be required in the absence of the establishment of a policy price on CO_2, where the size and the trajectory of such would have to be known well in advance sufficient to inform investment planning.

Figure 2

Comparison of declining capital costs of a carbon capture unit (projected 10% learning rate) added to a natural gas power plant by installation number and a $85/metric ton baseline incentive



Cost estimates (primary vertical axis) for each installation, normalized by annual carbon capture capacity (metric ton per year). After engineering the first carbon capture first, the engineering cost for follow-on near-identical units falls. Similarly, the actual hard costs of buying components and constructing the project fall as the entire supply gains experience with each successive unit. While the first facility capital investment cost, i.e., cost of construction of the unit, is $484/metric ton per year of carbon capture capacity, it is projected to fall to $362/metric ton per year by Serial #7. Falling capital costs in turn drive falling per unit capture costs. That is because as capital costs decline, subsequent projects have a smaller upfront need to raise funds, and thus have smaller annual debt and equity payments owed to financiers and investors, respectively. Similarly, other expenses linked to original capital cost, such as insurance, property tax, and replacement parts fall as well. On a per metric ton captured (levelized cost basis) the cost falls from $118/metric ton to $85/metric ton by Serial #7 (secondary vertical axis). Such a reduction in levelized cost gives reason to terminate any special early-stage commercialization incentives applied to Units 1-6, with Units 7 onwards supported only by the generally applicable $85/metric ton 45Q federal CO_2 capture and sequestration tax incentive. A 10% learning rate is conservatively applied based on carbon capture technology similarity to flue gas desulfurization systems, which have experienced a 12% learning rate on capital costs in the two decades since commercialization.[33]

Estimating the right level of support needed for each industry is complicated by differing cost estimate methodologies

Identifying the cost-optimal level of support is not simply a matter of calculating the average across industries as reported in the literature. First, capital, and operating costs as reported in a wide variety of published sources will vary depending on whether authors are discussing full costs of a risky FOAK project, estimates of NOAK costs after commercialization of CCS in a specific industrial application, or even idealized calculations of the theoretical costs to extract CO_2 depending primarily upon CO_2 concentrations in waste gas (e.g., Sherwood Curve studies).[r] Further, authors may not be explicit in their assumptions.

Policymakers can be forgiven for wondering why a pioneering FOAK retrofit CCS plant may require CO_2 incentives totaling over $100/metric ton for a specific industrial application of CCS, when DOE studies for the same industry report a "capture cost" of $55/metric ton. What is often not understood or explained is that the $55/metric ton likely refers to the carbon capture component (only) of a NOAK greenfield project, whereas the $100/metric ton likely refers to cost of capture, transport, and sequestration for an FOAK retrofit. As an illustration, only an experienced reader would grasp the full significance of the disclaimer below from a recent DOE study:

> *The cost estimates for plant designs that include technologies that are not yet fully mature (e.g., IGCC plants and any plant with CO_2 capture) use the same cost estimating methodology as for mature plant designs,* ***which does not fully account for the unique cost premiums associated with the initial, complex integrations of emerging technologies in a commercial application****. Thus, it is anticipated that early deployments . . . may incur costs higher than those reflected within this report.* [emphasis added][34]

It would be helpful to the industry if DOE added clarifications to its published CCS cost studies to clearly show cost profiles for both FOAK and NOAK projects, including estimates of the cost categories and dollar values of cost reductions that can be made between the two stages of project maturity. It would be even more helpful if DOE were to give estimates, even rough estimates, on the range of costs engendered by retrofit vs. greenfield projects, Finally, it would be helpful to document the range of extra costs that

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[r] See, for instance, Bains et al.,"CO_2 Capture from the industry sector", *Progress in Energy and Combustion Science,* 63(2017) pp. 146-172. https://doi.org/10.1016/j.pecs.2017.07.001

are associated with to-be-treated waste gases – prior to undertaking the carbon capture project – that have levels of contaminants such as SO_2, NO_2, or particulates exceeding sensitive CCS equipment tolerances. Each of the above-mentioned matters is important to accurately identifying levels of federal support needed for CCS projects.

CCS cost estimates in many industries are only approximate because each industrial setting requires customization and commercial demonstration

Currently there are two major capture chemical processes operating at a global scale. One uses an aqueous amine solvent that bonds to CO_2, and the other dissolves CO_2 in cold methanol or propylene glycol. The former was patented in the 1930s and the latter first deployed in the late 1950s.[35,36] While these carbon capture technologies are now well established in certain industries for run-of-the mill industrial purposes, their transfer to new GHG abatement/pollution control applications will require a thoughtful and concerted effort (see discussion of examples below). Before discussing how to scale up carbon capture in many different applications, it is instructive to discuss why only one or two first deployments within a specific industry will not suffice as a proxy for CCS costs in other industries.

Today's global-scale carbon capture deployment experience is primarily limited to non-combustion applications (thus without combustion contaminants) in which CO_2 is scrubbed from mixed gases with generally low contaminant levels[s] and at high pressure.[t] These characteristics have the effect of minimizing the relative size, operational complexity, and cost of capture equipment.[u] Examples of low contamination/high pressure include natural gas processing, ethanol production, steam methane reforming, and coal gasification.

In contrast, and apart from hydrogen-producing methane reforming units, applying CCS to most industrial and power units requires dealing with contaminated/low pressure flue gas streams from the combustion of fossil fuels, e.g., from coal and biomass power plants, furnaces burning solid and gaseous waste, catalyst regenerators, and cement kilns. To

[s] An exception is found in natural gas processing plants that sometimes need to remove substantial amounts of hydrogen sulfide, a situation not commonly found in post-combustion carbon capture environments.

[t] An exception to "low contaminants" is natural gas processing of field gas that contains very high levels of H_2S (hydrogen sulfide gas), but this is a not uncommon problem for which the natural gas industry developed solutions many years ago.

[u] Typically in the area 200 psi for steam methane reformers, 100 psi for natural gas processing, vs. 15 psi ambient pressure.

protect the equipment and processing chemicals of a carbon capture unit, these combustion-associated contaminants need to be removed prior to entering the capture unit. Further, when flue gases are at ambient pressure and elevated temperature, the size of carbon capture process vessels must be larger, sometimes substantially larger. These additional operational challenges raise CCS costs, making it essential to establish high enough FOAK incentive packages for each industrial application to fund examination of the full range of CCS engineering needs and solutions.

Significant customization for each application leads to uncertainty and high cost in FOAK projects

Unfortunately, in terms of the overall U.S. emissions reductions, only small volumes of emissions are generated in the low-cost and straightforward applications of CCS (e.g., ethanol and gas processing industries totaling ~60 million metric tons per year, as seen in **Figure 1**). The bulk of U.S. CO_2 emissions occur in settings where CO_2 emissions can only be captured at higher costs and with greater difficulty.

As noted, the major differences in capital and operating costs are driven by contaminants, concentration of CO_2, and operating pressures. Because CCS must be applied across many different industries, often with many different common plant configurations in any given industry, this means that CCS may have dozens of projects that are effectively FOAKs.

This inherent heterogeneity of carbon capture projects across industrial settings means that FOAK installations must provide a large construction cost overrun cushion (i.e., contingency account) as a risk management method. These additional project budget items will decrease as experience increases. Evidence suggesting this is found in NETL's most recent fossil fuel power plant cost baseline study in which the size of contingencies for an unabated pulverized coal plant are compared to a similar CO_2 capture-equipped plant.[37] The incremental cost of adding carbon capture equipment to the ~700MW power plant is \$1.42 billion with risk contingencies built into the contractor's fee of 35% (as percentage of equipment, labor, and construction).[v] If industry standard contingencies of 20% are used (as they would be on a 2nd, 3rd or 4th project), the carbon capture project cost would have dropped to \$1.28 billion, a difference of \$140 million, or 10%. Another

[v]The figure ~700MW was used because DOE was only examining newly built plants. When they sized a new coal plant with carbon capture, they scaled up the unabated 687 gross MW plant to 776 gross MW in order to provide extra electricity and steam—a practice that is not relevant to isolating the cost of CCS alone. Thus, we had to adjust cost of the unbated coal plant upwards before comparing. We used an engineering scaling factor of 0.70. I.e., \$Cost of unabated 776MW plant = \$Cost of 687MW plant x (776/687)^0.70.

example: MHI, the vendor for the very first large post-combustion carbon capture unit on a U.S. coal plant, estimated that it could reduce costs by 30% for a second unit, based on lessons learned from experience with the first unit.[38]

Site-specific requirements lead to additional uncertainty in retrofit projects

Differences among CCS projects further increase when carbon capture technology is applied as a retrofit to an existing emitting facility, as opposed to being built *de novo* in a greenfield facility. Although the basic components within a given industry (e.g., cement kilns used for calcination, combustion turbines for NGCC electricity generation) are roughly similar, each emitting facility still has idiosyncratic elements that require site-specific solutions. These include building footprint; facility layout and space limitations; facility operational profile/capacity factor; site-specific fuel or feedstock mix; flue gas flow rate, composition, pressure, and temperature; and constraints on facility steam, heat, water, and electricity balances.

Gathering a portfolio of experiences for each industrial application is needed to build a body of knowledge sufficient to improve efficiencies and lower costs. These costs are likely to fall once sufficient experience per application has been achieved, typically after application to three to seven facilities. Notably, however, to be eligible for DOE LPO low-cost loans (or guarantees) under section 1703, a “new or significantly improved technology” must be at the core of the project, whereby it has “been used in fewer than three commercial facilities in the U.S. in the past five years.”[39] This criterion may prove to be too restrictive, given the anticipated effort needed to commercialize CCS across a breadth of industries. Notably, the new $250 billion 1706 program (Energy Infrastructure Reinvestment Program) is not burdened with these three commercial facilities limits, an important policy improvement.

Achieving cost declines requires learning and experience for each type of application

Application-to-application variations in flue gas temperature/pressure and flue contaminants present issues that are likely to be resolved only through practical experience.

Equipment size requirements differ significantly based on operating pressure and temperature

With respect to component differences, a prominent example is the absorber vessel where produced gases are treated with an aqueous amine solvent solution that bonds to CO_2. In a hydrogen steam methane reformer (SMR) plant, treating process gas with 15% CO_2 at a temperature 37.8°C and high pressure 24.1 bar, the absorber vessel must handle about 0.11 million m^3/hour of input gas flow to capture one million metric tons of CO_2 per year.

In contrast, to capture the same annual one million metric ton mass of CO_2 within an NGCC, the absorber vessel will treat flue gas characterized by lower concentration 4% CO_2, higher temperatures at 110°C and much lower pressure of 1 bar. The absorber vessel in this less favorable situation processes 2.2 million m^3/hour of input gas flow. Therefore, the absorber vessel capacity in the NGCC case must be 20 times larger than the equivalent in an SMR application to capture the same mass of CO_2 on an annual basis. The input gas CO_2 concentration, temperature and pressure drive the difference in this component sizing.[w]

Vendors of carbon capture systems and process units may well have significant experience with manufacturing and delivering absorber vessels for the SMR CO_2 capture systems that are common in fertilizer plants. Building absorber vessels for capacities 20x larger as needed in NGCC applications will, however, require different construction and/or transportation methods, e.g., the SMR absorber may be shipped as a preassembled unit, while the NGCC absorber likely must be made in pieces that require onsite assembly and welding. It will take experience to optimize the procurement of components for the new application.[x]

Equipment designs must be customized to the composition of the flue gases

The composition of flue gases inbound to the CO_2 capture system can vary based on application, even after contaminants such as SO_x, NO_x, and particulates have been removed. Returning to the steam methane reformer and NGCC examples, the flue gas

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[w] It is noted that while capacity may be 20 times as large comparing the two cases, physical size and cost do not scale linearly.

[x] For example, in some cases, it may be more cost efficient to have multiple smaller absorber towers offsite rather than a single tower constructed onsite, or alternatively, towers constructed of steel cylindrical cross sections offsite but welded together in a column. Another consideration, larger components may be made offsite if the construction site is at the seacoast rather than inland where the pieces must fit under highway bridges.

oxygen levels are <2% and 12% respectively. [y,z] Oxygen can react with the amine solvent to create small quantities of undesirable emissions of formaldehyde and acetaldehyde, both of which are volatile organic compounds (VOCs) and HAPs under EPA National Ambient Air Quality Standards (NAAQS). What this means is the capture system for the NGCC may need an extra treatment step to de-oxygenate the flue gas before treatment. The precise amount of pre-treatment needed to control VOC/HAP formation will need to be learned from experience and practice over time. (Refer to Theme 5 for a deeper discussion on this subject.)

Examples of facilities that appear to be in the "same industry" but whose pre-treatment waste flue gas streams differ markedly – and whose carbon capture configurations and costs will thus also differ meaningfully – are outlined as follows:

- Cement plants that combust relatively clean fuels vs. cement plants that burn tires, petroleum coke, railroad ties and high sulfur coal;
- Natural gas combustion turbine power plants with significant excess oxygen contamination vs. coal power plants (or gas-fired steam boilers) with low excess oxygen;
- Oil refinery catalyst regenerators in fluid catalytic cracking units that use partial oxidation (producing carbon monoxide) vs. those using full combustion (producing CO_2; and
- A large cohort of oil refinery fluidized catalytic cracking units (FCCUs) that became subject to 2005 EPA emissions rules regarding HAPs, by virtue of their owners having made substantial modifications to the FCCUs and being subjected to an industry-wide consent decree.[40] This cohort of FCCUs has relatively low levels of HAP emissions, vs. those that still operate on pre-2005 air permits (usually with high SO_x, NO_x, and PMs).

[y] 1.67% from DOE/NETL Comparison of Commercial, State-of-the-Art, Fossil-Based Hydrogen Production Technologies (2022), Exhibit 3-18 (stream table) at stream point #17.

[z] 12% from DOE/NETL Cost and Performance Basline for Fossil Energy Plants Volume 1 (2019), for Case 31B, Exhibit 5-22 (stream table) at stream point #12.

Even after commercialization, CCS for GHG abatement/ pollution control lacks long-term revenue sources other than federal incentives; there is no enduring demand-side signal

Federal supply-side incentives such as grants, loans and tax credits are crucial because carbon capture provides a significant public good by addressing the negative externality of GHG emissions in the absence of carbon pricing or taxes. However, in the absence of carbon pricing, carbon taxes, or carbon emissions controls, a CCS project has no other reliable revenue source but those federal incentives.

Very broadly, industries are formed when goods/services can be supplied at a cost that a meaningful base of customers would willingly pay – or can be forced to pay. In the case of conventional/non-GHG pollution control, or provision of a service without generating conventional pollutants, the usual governmental policy mechanism has been to force demand, with costs gradually declining over time. CCS has a unique challenge in that there is neither an inherent demand for the service of limiting CO_2 emissions nor a government compulsion to buy the service.

An example of what can happen when there is such a requirement can be found in the wind and solar industries. Wind and solar developers benefitted from state renewable portfolio standards (RPS), mandates that required utilities to purchase a specified fraction of total generation from these renewable resource facilities; these costs were then passed on to utility customers, where RPS mandates required utilities to enter into long-term power purchase agreements (PPAs) with wind and solar projects even, in the days when wind and solar generated electricity was 2-5x higher than the cost of running existing fossil generation.[41]

There was fierce competition among wind and solar projects to be the low-cost provider inside the small arena of other RPS-eligible projects, but wind and solar projects did not need to compete in the broad electricity market with the much cheaper fossil energy. Those high early wind and solar power purchase agreement (PPA) prices would have been higher still in the absence of federal wind production tax credits (PTCs), solar investment tax credits (ITCs), and subsidized section 1705 loans for many projects during the 2009-2012 period.[42] Nonetheless, the main driver of the renewable electricity industry was the forced purchase of project output based on state RPS standards (a demand-side policy), with the federal government modestly reducing costs to complying utilities through economic incentives (supply-side policy).

Pollution control devices are only installed if they are compulsory or if they are profitable. In the case of sewage treatment plants, automobile catalytic converters, coal plant sulfur scrubbers, and gas power plant NO_x controls, compulsion was the driver.

Compulsion is still absent in the case of CCS. There are no generally applicable federal CO_2 emissions limits, with the notable exception being new power plants (at a standard that is practically binding only to new coal power plants). In the case of CCS applied to electricity generation, there are no state policies or mandates that force demand for low-emissions CCS-enabled baseload or dispatchable generation capacity. With respect to CCS applied to industrial facilities, there are no enduring demand signals for low carbon intensity for cement, steel, ammonia, or pulp and paper. The California Low Carbon Fuel Standard (LCFS) program has yet to spark any liquid fuels driven industrial CCS projects. A few initiatives such as the First Movers Coalition, Breakthrough Energy's Catalyst program, and Frontier have started driving the creation of demand for low-carbon industrial products, but these initiatives are still at the early phase.[43,44,45] Since markets for industrial commodities are highly competitive and trade-exposed, the suppliers of industrial commodities cannot easily, voluntarily add a premium price for decarbonized products produced using CCS.

In the absence of compulsion, CCS must be profitable for those emitters willing to voluntarily undertake installation of capture equipment. That profit today is solely provided by federal incentives, with project capital costs sometimes mitigated by federal grants, and cost of financing sometimes mitigated by federal loans.[aa]

Policy recommendations

The following is a set of policy recommendations that are designed to accelerate the deployment of CCS technologies in ways that will make carbon capture projects more investable.

[aa] It is acknowledged that little emphasis is being placed on sale of CO_2 to Enhanced Oil Recovery Operators (EOR), which is the only meaningful source of non-federal revenue/incentive for capture projects and has been the cornerstone of pioneering CCS activity to date. From a future economic point of view, however, since the 45Q incentive is (post-IRA) reduced by $25 per metric ton for EOR-injected CO_2 vs. geologic sequestration, the additional commercial revenue from EOR is counteracted by reduced federal incentive applied to EOR.

Policy support must address both commercialization and long-term operations

Essentially, a mixture of demand and supply-side support mechanisms are needed to (i) adequately support FOAK and NXOAK projects through to their end of life; and (ii) adequately support the NOAK projects through the end of their operational lifespans. Crucially, support for FOAK, NXOAK and NOAK needs to be promulgated simultaneously – and endure – to send a sufficient signal for developers to form an industry. Where there are no demand side mechanisms, the full burden falls on federal supply side mechanisms. Put another way, the \$85/metric ton 45Q tax credit will have to do "all the work on its own" in the absence of any demand side mechanism.

As such, the following three interrelated sets of recommendations address the needs for both FOAK and NOAK CCS:

- Strengthening and systematizing a mix of federal grants and loans for carbon capture projects to demonstrate a financeable commercial track record and drive costs down to baseline support levels. (Recommendations 1A, 1B, 1C);
- Creating an appropriate long-term baseline level of federal incentive/support at a level that can be reached by the cohort of commercialization projects. (Recommendation 1D); and
- Introducing demand-side policies to reduce the federal budgetary costs of baseline support needed. (Recommendations 1E, 1F, 1G, 1H).

Strengthen and systematize a mix of federal grants and loans for carbon capture projects to demonstrate a financeable commercial track record and drive costs down to baseline support levels

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Recommendation 1A. DOE should update the threshold of deployed projects to five projects from the current three projects by administratively amending the definition of "Commercial Technology" in the regulations governing eligibility for loans under Section 1703.

Currently a project is only eligible for a federally guaranteed loan under section 1703 if its technology *is* "New or Significantly Improved Technology" and *is not* "Commercial

Technology." Commercial Technology is not defined with reference to an installed base or period of operation in the authorizing statute (42 USC §16511).[46] However, the LPO regulations (10 CFR 609.2) define "Commercial Technology" to mean a technology "in general use" when LPO issues a loan terms sheet, with "general use" meaning the technology is already operating in three or more commercial projects in the U.S. in the same general application as the proposed project, and those reference three projects have all been operating for at least five years.

For CCS, the "same general application" definition should be narrowly interpreted to give recognition to the heterogeneity of industrial and power plant CCS applications. Thus, CCS in a blast furnace steel mill is a different "general application" than CCS in a direct reduction iron steel mill. Capturing carbon from flue gas in a Steam Methane Reformer hydrogen plant is a different "general application" than capturing carbon from process gas in an Autothermal Reformer hydrogen plant. Moreover, given evidence that three instances of CCS projects in each application may not drive the cost below a long-term baseline support level (e.g., cement, steel, black liquor boilers, NGCC, existing coal retrofits), the threshold for each application should be updated to five.

The Commercial Technology definition is regulatory, not statutory. As such, there may be flexibility for the DOE to set the threshold within which carbon capture applied to a specific industry is considered new or significantly improved technology. Note that the restrictions discussed above do not apply to the new four-year temporary $250 billion Energy Infrastructure Reinvestment section 1706 loan program.[47] Given that it conceivable some CCS projects may receive funding through 1706, but that NOAK costs may not be achieved before 1706 expires, there is added impetus to update the definition of Commercial Technology 1703.

Recommendation 1B. Considering the industry-specific commercialization trajectories of CCS as a pollution control technology, DOE should prioritize BIL grant funding to those FOAK applications that are still out-of-the-money even after taking account of IRA 45Q bonus tax credit value.

The post-IRA level of 45Q at $85/metric ton for geologic sequestration appears to fall short of covering the FOAK cost of CCS applications in refining, coal power, natural gas electricity generation, black liquor boilers, steel and FCCUs (see **Table 1** above). In part this is because inflation in project capital costs since 2018 has eroded much of the nominal increase from 45Q for GS from $50 to $85 per metric ton.[bb]

Without any mandate to mitigate GHG emissions, these industries would still not be motivated to apply FOAK CCS at their facilities due to high costs, even with the enhanced value of 45Q offered in the IRA. The new $85/metric ton baseline appears sufficient to sustain a later NOAK scale-up in some industries if capital goods inflation moderates but is not large enough to overcome the high FOAK and NXOAK costs of installations #1-6. This is of material consequence because the sectors that appear to be out-of-the-money for FOAK CCS are also the biggest stationary emitters of GHGs in the economy (see **Figure 1** above).

An additional incentive available only to first movers, i.e., an incentive supplementary to 45Q could offer an aggregate levelized incentive flow that is large enough to cover high capital investment costs and correspondingly high financing costs for FOAK facilities in these more expensive CCS applications. Funding for such an incentive could come from the BIL, specifically funds available under §41004 (development and demonstration projects), and §40304-40305 (CO_2 transportation and storage infrastructure). These sections account for the vast majority of the $12.1 billion allocated to carbon management under the BIL. DOE FOAs supported by these funds and could prioritize the applications that are currently out of the money. DOE's recently released Funding Opportunity Announcement (FOA) entitled "BIL: Carbon Capture Demonstration Projects Program (DE-FOA-0002806),[48] calling for a coal and a natural gas electricity facility with CCS, and two industrial facilities with CCS.

Carefully applied, and with the level of extra support declining as costs fall in later projects, these existing funds can stretch over a series of projects in multiple applications. **Figure 3** (below) shows the per metric ton cost of CCS applied to a NGCC electricity generation facility, with costs falling for each subsequent build (i.e., serial number of capture unit) due to a presumed 90% experience curve (10% learning rate). Installations #1 through #6 are all above the $85/metric ton 45Q incentive. However, assuming a 1,000,000 metric ton per year capture rate, the total grant value needed to bring these initial six installations to the current 45Q incentive is ~$481 million. Extending this logic to FOAK cement, black

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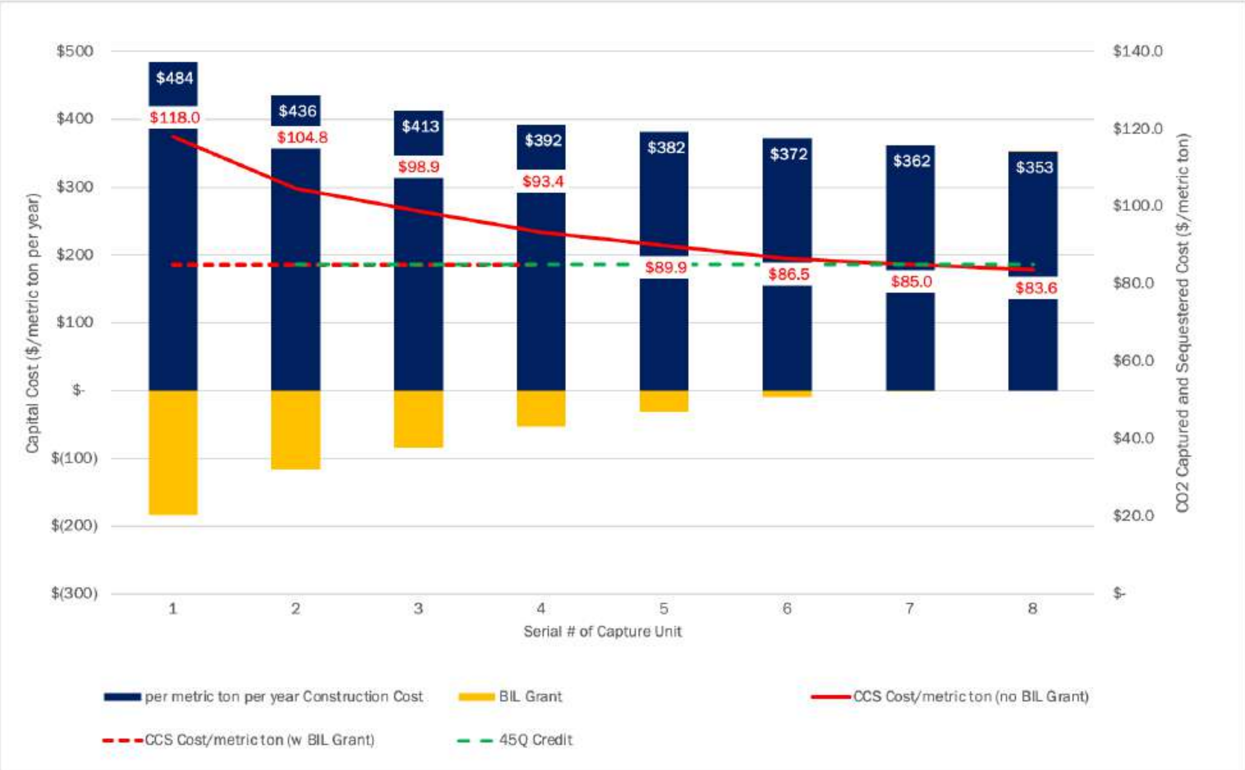
[bb] All things being equal, inflation probably has consumed about half the $35/metric ton increase in 45Q for GS sequestration. The CEPCI which stood at 603.1 at year-end 2018 and had risen to 701.4 by June 2021 (16% increase) and 832.6 by June 2022 (38% increase). For a carbon capture plant that would have cost $350 per metric ton/yr. of carbon capture capacity ($ 2018), the expected inflation in capital cost would have been $132 per metric ton/yr. Using a capital cost recovery factor of 10% and an annual fixed cost factor of 4% (of original cost), the extra capital cost would imply extra financing/fixed cost of $18 per ton captured (14% x $132). Higher electricity and natural gas prices have additionally eroded the increased incentive.

liquor boilers, coal power and hydrogen SMR production, the total cost of the grant supplement would be ~$2.8 billion, or about 23% of the total funds allocated to carbon management under the BIL.

Figure 3

Using a 10% learning rate, 45Q enhanced by BIL carbon management allocations is sufficient to make FOAK NGCC facilities work (with CCS economic incentives)



All FOAK incentives will have to accommodate the current high-inflation environment, which will have a material impact on development costs.

Recommendation 1C. Congress should allow, once appropriated, the stacking of grants and loans for CCS projects.

A generous combination of both grants and loans—not exclusively one or the other--in addition to the baseline level of support, is likely to be required for first generation CCS projects (FOAK and NXOAK). As noted, the main issue for FOAK and NXOAK projects is high capital costs as the industry learns to apply existing capture technologies in new settings; the most useful incentives are those that lower the cost of debt and equity, while giving access to debt and equity in amounts not normally available for risky early-stage projects. The earliest projects will probably need more grants (i.e., government-provided “equity”) but will have difficulty meeting credit standards for a high percentage of federally guaranteed debt. Later projects may be able to make do with less grant support but are likely to be more creditworthy and to merit a larger federally guaranteed loan. DOE should have appropriate flexibility to adjust the mix of grant and loan support as appropriate for project maturity.

Current federal law takes the opposite approach for LPO loans in a section of the IRA entitled “Denial of Double Benefit” that directly applies to the §1703 (now expanded to ~$50 billion of loan authority) and is also incorporated into new §1706 ($250 billion of loan authority). Currently projects that receive a federal grant (i.e., cost sharing agreement) are ineligible to access the low-cost debt capital provided by the LPO. The relevant statute bars loans to “projects under which funds, personnel, or property (tangible or intangible) of any Federal agency, instrumentality, personnel, or affiliated entity are expected to be used (directly or indirectly) through acquisitions, contracts, demonstrations, exchanges, grants, incentives, leases, procurements, sales, other transaction authority, or other arrangements, to support the project or to obtain goods or services from the project.”[49]

To provide adequate incentive for CCS build out, a “double benefit”, or stacking of grants and loans in project-appropriate proportion is exactly what is needed. In short, if a risky project needs a federal loan because it lacks access to private lenders, it probably also needs a grant because. The very same risks that deter lenders also deter equity investors. Grants partly solve the equity fundraising problem and LPO loans fully solve the debt availability problem. The universe of potential §1703 borrowers is already limited to projects that are risky and expensive precisely because they are not utilizing proven “Commercial Technology”, and hence there is little risk of excess profits because these risky projects received a mix of grant and loan support. It is important that these “Denial of Double Benefit” requirements for both §1703 and §1706 be changed in the future and that DOE, as the manager of both the loan and grant programs, be authorized to determine the optimal mix of loan and grant support for projects at various stages of commercialization maturity.

Create an appropriate long-term baseline level of federal incentive/support at a level that can be reached by NOAK projects, after establishment of a commercialization track record

Provided that a commercialization track record is established (i.e., a series of FOAK and NXOAK installations), and presuming capital and operating costs have been driven down, a long-term baseline level of support needs to be set to ensure operations in the absence of a material federal cap or price on CO_2.

Recommendation 1D. Funding from the BIL and/or the IRA should be made available for FOAK applications that are currently out-of-the-money given the current value of 45Q to cover ongoing operating costs from year 13 onwards.

Under current 45Q, the capture/sequestration incentive terminates after a project has collected the incentive for 12 years. If there is no federal prohibition on CO_2 emissions or sufficient penalty, then there is no source of revenue that will cover the cost of operations, maintenance, and sequestration beyond 12 years. It is highly likely that a capture project would be mothballed before the beginning of year 13. The cost levels in Table 1 are based on a high capital recovery factor of 13% calculated for FOAK projects, based on the presumption that the facility operates for 12 years and then may shut down in year 13. The $85/metric ton is enough to fully amortize the initial capital investment over 12 years plus covering non-capital operating costs of $40-45/metric ton. These non-capital costs are annual fixed, variable, and energy-related operating costs (~$25-30/metric ton) plus sequestration costs ($15/metric ton). To keep projects running, these non-capital costs need to be covered in year 13 onward in the absence of any other policy.

As a remedy, perhaps as a bridge to a long-term broader policy of carbon emissions limits or carbon pricing, a follow-on incentive could be offered to offset some portion of the ongoing operational costs after year 12.

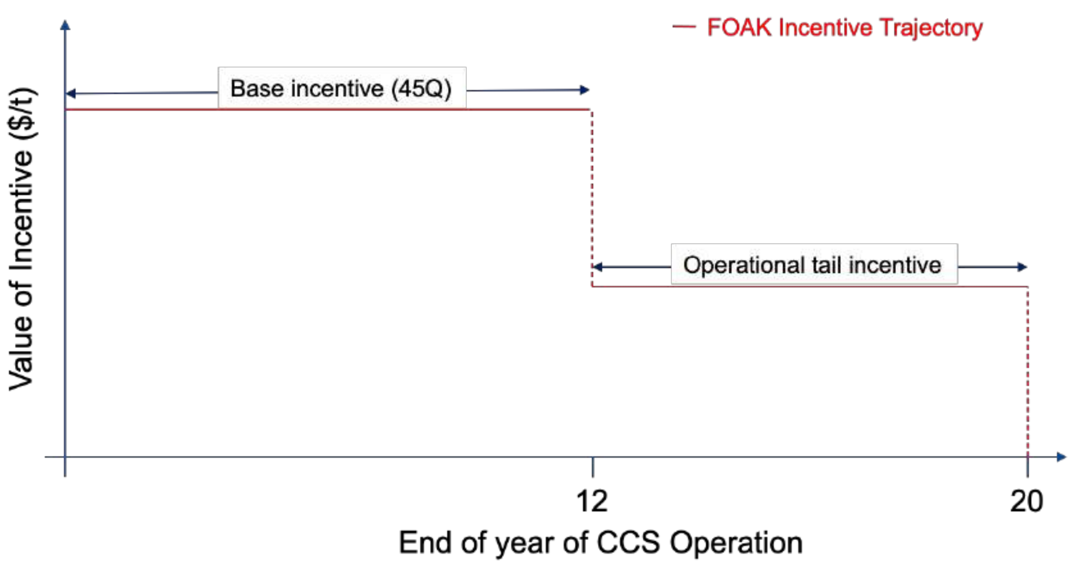
Even without a tax law change, there may be some existing programs with the flexibility to fund such a follow-on incentive to some degree. Such a follow-on mechanism, and combinations of other programmatic options might then be used in a stacked fashion and tied to a cost-sharing agreement with the investor/taxpayer/grantee. The BIL through §41004 (development and demonstration projects) and §40304-40305 (CO_2

transportation and storage infrastructure) could be one source of funding, where the grant structure is a set of annual payments to a competitively awarded grantee.

Alternatively, the IRA (§60103) includes $27 billion for the Greenhouse Gas Reduction Fund, to help fund state and local green banks and spur investment across a variety of areas, including decarbonization of industrial processes. As written, these funds could be offered to FOAK developers for CCS applications that are currently out of the money (e.g., NGCC, steel) and could be allocated on a reverse auction basis upfront. This would have the benefit of creating FOAK investor certainty, while not committing the funds for years one through twelve (until they are needed), thereby offering financing flexibility for such green banks. Taken together, the base (45Q) and "operational tail" incentives could cover CCS capital and (up to all) operational expenses for 20 years, matching the actual expected lifetime of the assets, thereby making more efficient use of invested capital. **Figure 4** below provides a notional trajectory for CCS applied to a given industry.

Figure 4

Matching CCS operational lifetime with incentive value: step-down trajectory



Introduce demand-side policies to reduce the federal budgetary costs of baseline support

To complement supply-side mechanisms, a blend of long-term, predictable demand side incentives should be used wherever possible. Likely implementation mechanisms for investable demand side alternatives follow.

Recommendation 1E. All state governments should include CCS as an eligible compliance option for state-level decarbonization mandates. Further, CCS projects should be treated as pollution control projects and receive the same state tax and local property tax treatment as pollution control projects for criteria air pollutants.

Making CCS an eligible option for compliance with sector-specific state mandates could create additional demand for CCS projects, but there is presently no state-level economy-wide mandate, carbon tax, or cap-and trade program that includes industrial or powerplant CCS as a compliance option. "Compliance option" means that an emitter facility capturing and sequestering a ton of CO_2 can legally treat that ton as "not emitted." One limited state program, the California LCFS, does allow CCS as a compliance option. However, the California LCFS applies only to projects linked to or substituting for transportation fuels (other than an exception for direct air capture).[cc] CCS is not recognized as a California GHG compliance option outside of the transportation sector. For California's broad-based cap-and-trade mechanism, a ton of CO_2 that has been captured and sequestered is nonetheless treated as though the ton of CO_2 had been emitted to the atmosphere. A power plant that captures and sequesters one million tons of CO_2 needs to buy the same number of carbon allowances as a power plant that vents one million tons of CO_2 to the atmosphere.

Outcome-based targets using carbon intensity measures are technology-agnostic and focus on emissions. From this perspective, next-generation state-level decarbonization mandates – beyond energy industry specific approaches like an RPS – will offer an important, enduring demand signal for CCS. However, to be effective, much like the RPS provided a mechanism to socialize the cost across a wide purchasing base (i.e., electricity

[cc] A good summary of the LCFS program is found at https://ww2.arb.ca.gov/resources/documents/lcfs-basics

customers), the production of low carbon-intensity products such as steel, cement and fertilizer with CCS will require a similar complementary demand-side component.

By the same token, many states exempt pollution control equipment from state sales taxes and local property taxes but do not necessarily apply those exemptions to GHG control equipment. Sales taxes significantly raise initial capital costs to construct projects, and local property taxes can be a significant annual fixed costs for CCS projects. Taken together, these costs could account for ~13% to value of the $85/metric ton 45Q tax credit.[dd]

Recommendation 1F. FERC (ISO/RTO markets) and state PUCs (non-ISO markets) should develop rules and incentives, respectively, for clean baseload electricity, which would materially improve the economics of CCS applied to electricity generation.

If CCS is to be deployed for existing fossil fuel electricity generation as one approach to help achieve the Biden Administration's goal of a net-zero U.S. electricity grid by 2035, then a value should be placed on dispatchable zero carbon electricity generation. Implementing this concept is, however, complex because there are two parallel electricity regulation systems in the US: (1) the ISO/RTO-managed, FERC-inspired "organized markets" and (2) the traditional state-regulated markets.

Today within organized markets (ISO/RTOs), whose rules are regulated by FERC, there are two key markets: real-time spot markets for electric energy (MWh) and medium-term capacity markets (MW) to ensure reliability.

In the day-to-day electricity spot energy market, the "security constrained economic dispatch" concept dictates that the lowest marginal cost generation gets dispatched first, unless there is a reliability-must-run designation for a generator designed to ensure grid reliability (such as gas-fired generation ramping up in the late afternoon to prepare for an evening surge of demand and PV solar supply waning). This aspect of the spot market means that CCS-enabled generators, which have non-zero variable generation costs, are

[dd] Take the example of a carbon capture project with an initial capital cost of $400/metric ton-yr. of capacity. If 50% of the capital is subject to a 10% sales tax, that raises capital cost by $20/metric ton-yr., which translates to ~$3/metric ton on a levelized basis captured. Property tax at 2% on the $400/metric ton-yr. translates into an additional $8/metric. Taken together, this $11/metric ton consumes almost 13% of the value of the $85/metric ton 45Q tax credit.

unlikely to run at a high enough capacity to reliably recover capital and operating costs. However, RPS-qualifying "policy resources" such as wind and PV solar have zero variable costs and thus are likely to run whenever available, with their capital costs directly covered by long-term power purchase agreements.

In capacity markets, there are typically no mandates or premiums to ensure that a portion of the firm generating resources ensuring grid stability will be low- or zero-carbon. Load-serving entities (i.e., utilities with an obligation to provide electricity to customers) must sign contracts to support standby generators with enough capacity to support their peak loads. In most markets these standby capacity contracts are far too short in duration and too low in price to support construction of new, efficient, but unabated natural gas fired-units; standby capacity contracts also fall far short of the terms needed to support the more expensive new CCS-abated dispatchable units.[ee] ISO-New England, for example, conducts auctions for one-year capacity contracts, three years in advance, with recent prices being in the range of $30,000 per MW-year.[50] That $30,000/MW-year figure, even if certain for a period of 15 years instead of one year at a time, would only amortize 25% of the capital cost of a new NGCC unit, and ~10% the cost of a CCS-enabled NGCC unit.[ff]

FERC, via its oversight of ISO/RTOs should consider rule updates that fairly compensate zero-carbon generation units with high effective load carrying capacity, especially given that intermittent renewables will most likely continue to grow in deployment. An example for consideration: a long-term capacity agreement mechanism on a $/kW basis in addition to a "green premium" provided such capacity achieves specified carbon intensity performance specifications during operation. Another example: a priority dispatch rule that considers the marginal offer price of generation in addition to carbon intensity of such generation. A final example: disaggregated capacity market design to better account for the value each generation source may provide.

Within non-ISO regions, state PUCs could incentivize clean baseload generation based on the ownership of the generation facility. For regulated vertically integrated utilities, CCS coupled with electricity generation could be rate-based, allowing for capital cost recovery. For independent power producers, contract mechanisms could be created such as take-or-pay (if available) or tolling agreements, which consider both the marginal price

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[ee] In ERCOT (Texas) there are no capacity markets at all, which may be one source of the declining reliability of the Texas grid.

[ff] $2.50/kW-month equals $30,000/MW-yr. NPV of $30,000 for 15 years at a 10% discount rate = $251,000. The most recent US DOE NETL fossil energy power plant "baseline study" (2019) estimates new NGCCs (Case B31A, p. 527/598) at $1.04 million/MW and new CCS-NGCCs (Case B31B, p. 546/598) at $2.6 million/MW.

of dispatch and the carbon intensity of generation. State PUCs would need statutory authority/direction from their legislatures to compel regulated utilities to acquire CCS-enabled (or for that matter, nuclear, geothermal, or biomass) dispatchable power rather than power from cheaper unabated natural gas plants.

Recommendation 1G. The Department of Transportation through the BIL should support the market for low-carbon industrial products by mandating requirements tied to funding

The Administration is already on track to support a recommendation on market support for low-carbon industrial products. The Council on Environmental Quality and White House Office of Domestic Climate Policy established the *Buy Clean Task Force* to promote the use of construction materials with lower lifecycle embodied emissions in February 2022 and have been developing recommendations to launch pilot programs for federal procurement of clean construction materials.[51] This effort could be augmented by having requirements – based on, for example, a proportion of total funding – where projects receiving federal funds must incorporate low carbon intensity (CI) materials or allow a price premium for such materials.

As a start, the Biden administration has announced efforts to expand the *First Movers Coalition*, an industry initiative to commit to purchase low-carbon products, to cover four sectors – aluminum, cement, chemicals, and carbon removal – in addition to steel, shipping, trucking, and aviation.[52] The federal government should also consider supporting those states without clean procurement commitments, by offering funds to introduce a clean procurement program.

A key source of funding for federal support can be found in the BIL, where the DOT has substantial responsibilities for shaping the procurement of materials for federally supported projects. In support of these efforts, the newly formed Joint Office for Energy and Transportation (JOET) – currently focused on electric vehicle infrastructure build-out[53] – could be expanded to provide tools to help material suppliers meet lower CI targets to access BIL funding. For example, JOET could lead an effort to combine the LCA tools developed by DOT (Pave Tool)[54] with those developed by the various offices in DOE (e.g., NETL LCA).[55]

Recommendation 1H. To enable the implementation of Recommendation 1G, the DOE should establish rigorous and transparent life-cycle emissions standards for industrial products and a certification program for low-carbon industrial products.

For all these activities, standard, transparent methodologies for estimating life cycle emissions are essential for meeting net zero targets. Such methodologies for life-cycle emissions are also crucial for implementing federal or state procurement programs for low-carbon industrial products. This has been widely recognized as an important step in enabling low carbon intensity products and processes,[56] especially given the heightened interest by various stakeholders and related concerns of "greenwashing."

A certification program could help instill confidence in the market for low-carbon products (including industrial heat) by clearly signaling differentiation that may warrant a price premium, depending on voluntary or compulsory mandates. The goal of such a certification program would be to create confidence through a standardized process and assessment criteria, like the EPA's EnergyStar program. Tools and methodologies already exist within various departments, agencies, and national laboratories, to create a similar program for low-carbon products. Examples of existing approaches include, the GHG LCA used within the Technical and Project Management Division at the DOE LPO, the Treasury Department as part of its assessment of 45Q credit allocation procedure and the GREET Model developed by Argonne National Laboratory.

THEME 2: TAX CREDITS NEED TO BECOME MORE EFFICIENT AND ACCESSIBLE

IRA provides a partial solution; further updates may eventually be needed so that a higher portion of the cost of tax credits flows to the intended recipients

Overview

While the prior section described the *magnitude* of incentives needed, this section describes the challenges that arise when the *form* of incentives diverges from investor requirements. Specifically, this section discusses tax credits, the tax equity market, and the reasoning as to why such incentives are a challenge to utilize efficiently for projects incorporating emerging decarbonization technologies such as CCS. Moreover, given the projected increase in the size of the tax credit market, there will likely need to be an expansion in the number and kinds of entities making use of such corporate tax credits.

With respect to the efficient utilization of tax credits, the following explanation is instructive. When $1.00 of tax credit (such as the CCS incentive under Section 45Q) is claimed by a corporation, the Treasury forgoes $1.00 of tax revenue; but it is possible that considerably less than $1.00 reaches a CCS project. If a CCS project earns $1.00 of 45Q but cannot itself use the tax credit (for reasons described below) and transfers the tax credit to another party for e.g., $0.60, there is an inefficiency from the perspective of the developer. The tax credit incentive is not efficient when 40 percent of the cost to taxpayers never reaches the intended beneficiary. This poses yet another challenge for carbon capture projects that earn tax credits: to smoothly monetize those credits. To the extent that projects – especially carbon capture projects – may be challenged to efficiently use the tax credits they have earned, tradeoffs between tax compliance regulations and the practical ability of developers to efficiently use the credits will have to be considered by policymakers.

Further, consideration will have to be given to the new, expanded supply of tax credits for all clean energy projects provided by the IRA. Attracting new participants to make use of ("monetize") transferred tax credits, thereby creating new sources of financial capital for CCS projects, should be a first-order priority of policymakers. The current pool of tax credit consumers has limited capacity to monetize additional credits, given a combination of relatively low corporate tax rates, as well as longstanding federal limitations on a corporation's pre-credit federal tax liabilities that can be offset using corporate tax credits. In theory, there is more than enough remaining taxable corporate income across all sectors of the U.S. economy to fully utilize the new tax credit supply generated by IRA. However, most of these firms are not familiar with federal clean energy tax credits. As a result, it is imperative that well implemented direct pay and transferability rules create the conditions to attract the needed participants to monetize the opportunities presented in the IRA.

The combination of monetizing tax credits for CCS projects, coupled with the overall expanded supply of clean energy tax credits created by the passage of IRA may also cause friction for potential CCS project owners. Additional elucidation of the reasoning is as follows:

1. **Decreased corporate tax rates reduce size of "market" for tax credits.** The total demand for tax credits is a function of by total U.S. federal corporate "pre-credit" tax liability, i.e., U.S. corporations' aggregate income tax liability *before* the application of tax credits to reduce final the ultimate tax payment amount owed. Total pre-credit corporate income tax liability fell sharply after the 2018 corporate tax rate cut. IRS figures show that corporate net income subject to tax in 2019 was 1.73x the 2017 figure, but pre-credit corporate tax liability for 2019 was only 1.07x the 2017 figure. That is, taxable profits rose 73%, but pre-credit tax bills rose only 7%. [gg,57,58,59]
2. **Climbing tax credit claims, boosted by new credits in recent legislation.** Meanwhile, corporations' use of tax credits climbed, with 2019 credits claimed being 1.33x the 2017 figure. As a result, corporations' ultimate corporate *post-credit* tax payments in

[gg] These figures are derived from a series of reports published annually by the IRS analyzing corporate tax payments. The cited figures are derived from Table 1 (part 1 of 2): Returns of Active Corporations for years 2019, 2018, and 2017.

2019 were 0.97x the 2017 figure, even though taxable income had risen 1.73x. The supply of tax credits then grew further with the CHIPS and Science Act (2022) adding $24 billion of high tech-oriented credits and IRA 2022 adding another $185 billion of decarbonization-related corporate tax credits ineligible for cash refundability. [hh]

3. **The largest U.S. GHG emitters have limited ability to use tax credits directly and will thus be heavily reliant on credit transfer mechanisms.** With demand having fallen and supply of credits rising, decarbonization-related tax credits face an extra challenge. Unlike high tech industries (directly using R&D credits) or the pharmaceutical industry (directly using Orphan Drug Tax Credits), the major GHG emitting industries who would ordinarily be expected to directly use decarbonization-related tax credits earn relatively small amounts of taxable profits. As shown below (**Table 2**), in 2019, the industries that emitted 87% of U.S. stationary GHGs only earned 4% of U.S. taxable corporate income. Thus, to capture value from tax credits—thereby making tax credits a meaningful lever over corporate investment—the major GHG emitters are likely to be disproportionately reliant upon ability to smoothly transfer credits to 3rd parties that pay more federal income taxes.
4. **If tax credit values do fall (rising supply of tax credits and slackened demand from 2018 rate cuts), the value of tax credits may fall under pressure.** That may be especially true if rising interest rates trigger a recession. It is impossible to forecast future values of tax credits, but typically when supply of a good rises and/or demand falls, the price of that good falls—whether the good is a commodity, a currency, or a tax credit. That trend could be counteracted if the current "market" for acquisition of tax credits can be expanded from its current narrow base of highly sophisticated financial institutions to a broader group of smaller, less sophisticated corporations.
5. **If tax credit values do fall, despite Congress' attempts to ease transferability, carbon sequestration credits may be especially hard hit.** Other things being equal, tax credits designed to promote carbon capture are more complex to earn and harder to keep than other production-oriented tax credits (i.e., the wind PTC). For example, if a MWh of wind is produced and delivered to the power grid, a taxpayer's claim for the associated §45 wind production tax credit is unlikely to be disqualified by the IRS. The IRS has no interest in the ultimate disposition of electricity. By contrast, for the IRS to accept a 45Q claim for a metric ton of CO_2, that ton needs both to be captured by a qualifying facility and then injected into a subsurface well that has met EPA regulations and has obtained certain approvals under both the EPA's Underground Injection Control (UIC) program and Greenhouse Gas Monitoring, Verification, and Reporting

[hh] JCT-18-22 This $185 billion figure is the 2023-2031 IRA clean energy corporate tax credit sum after subtracting estimates for credits claimed under special cash refund provisions and clean vehicle credits aimed towards individuals.

Program. Failure to correctly obtain and maintain these EPA approvals and to file related certifications to the IRS can disqualify captured and sequestered tons. Further, tons of CO_2 that subsequently leak will trigger repayment of the 45Q tax credits from parties that previously used those tax credits. These factors make 45Q credits more complex than analogous renewable energy credits and increase perceived risks among potential investors or to reduce tax credit acquirers. liabilities for past tax years. In short, our concern is that if the general tax credit market catches cold, the carbon sequestration tax credit market is likely to catch pneumonia.

Recent legislation

In broad terms, the IRA continues to rely on an appetite for tax credits by corporate taxpayers to accomplish decarbonization objectives. However, the IRA broke the *de facto* monopoly of traditional tax equity partnership transactions as the mainstay of tax credit monetization.[ii] This was accomplished through tax credit transfer provisions and, to a lesser extent, by creation of a window of tax credit “direct pay” for project owners (both to be discussed in detail below). The Joint Committee on Tax (JCT) analysis shows 84% of the revenue impact of the IRA tax credits arising from corporate taxpayer participation (either in tax equity partnerships or via new transfer mechanisms), with the remaining 16% of budget impacts related to the new “direct pay” mechanism (see new Code 6417 “Elective Payment of Applicable Credits” created by Sec. §13801(a) of the IRA).[jj]

In the post-IRA environment, tax-exempt government, co-op, and tribal[kk] entities will be able to directly earn cash from energy tax credit incentives of all types. Similarly, private entities will be able to transfer energy tax credit incentives of all types. Finally, a hybrid system for private entities was created specifically for a limited subset of energy tax credit incentives for the early years of a project’s life.

[ii] For sake of brevity, simpler leasing structures that have been successfully used to monetize solar ITCs are not discussed here.

[jj] See JCT August 9, 2022, JCT-18-22, which is the Joint Committee on Taxation budgetary scoring estimate of the Senate-passed IRA. We calculated the 77/23 split by dividing the 2022-2031 total direct budgetary outlays of $35.9B on p. 4 [1] by the $220.7B sum of all the corporate tax credit outlays shown for Subtitle D (pp. 3-4) except the vehicle credits that are primarily claimed by individuals.

[kk] Strictly speaking, Alaska Native Corporations are taxable corporations, and some have made use of energy tax credits such as §48 wind PTCs in the past. None of the other “tax-exempt” beneficiaries of direct pay have been able earn and use energy tax credits in the past.

The direct payments apply to two sets of entities:

- For all the various clean energy programs (existing and new) that use corporate production tax credit and investment tax credit incentives, the IRA rectified a longstanding inequity by allowing non-taxpayer owner/operators of clean energy projects to claim the cash value of the incentive from Treasury for the life of the incentive. The parties benefitting include the Tennessee Valley Authority, tribes and Alaska Native Corporations, states, and locally owned utilities, and electric co-operatives (see §6417(d)(1)(A) within Sec. 13801(a) of the IRA); and
- For certain specified credit programs only, the IRA also authorized corporate and partnership owners to be able to receive a cash payment in lieu of the credit during the first five years after the project in-service date. These specified credit programs are:
    a. 45V hydrogen manufacturing tax credit (up to \$3/kg H_2) (see §6417(c)(1)(B) of the IRA).
    b. 45Q (CO_2 sequestration) as amended to new higher credit levels of \$85/metric ton for geologic sequestration and \$60/metric ton for EOR (see §6417(c)(1)(C) of the IRA).
    c. 45X Advanced Manufacturing Production Credit (see §6417(c)(1)(D) of the IRA).

The balance of 45V, 45Q, or 45X credits, e.g., the last seven years for 45Q, would then be transferable, i.e., would be able to be sold in a straightforward manner from taxpayer-owners who had generated the credits to other taxpayers who needed the credits (see 6418 within Sec. 13801(b) of the IRA). Unlike direct pay (which does not rely on any party having tax appetite), the transfer mechanism is intended to simplify monetization. Nevertheless, it still assumes and relies on finding a third-party corporation that has a need for tax credits that a decarbonization project lacks.

The focus of this section addresses the open issue of whether and how corporate and partnership developer/owners of CCS projects can make use of the new regime of 45Q, with five years of direct payments followed by seven years of transferability.

Link to investability

Cash flow is fundamental to investment quality. Cash is needed to cover fixed and variable operating expenses, pay debt service, and make dividend payments to investors. In contrast, the entire federal support system for clean energy has relied not on cash, but on non-cash (limited exceptions in IRA), non-tradeable (changed in IRA), idiosyncratically designed, and frequently altered corporate tax credits. This contrasts with other countries that have methods to support decarbonization with cash.[ll] There is somewhat of a disconnect between what investors/lenders prefer compared to what the U.S. government offers. The disconnect has not been an insurmountable barrier for industries such as wind or solar because their basic cost of capital and operations are covered by state-mandated, long-term, cash-generating, energy sales contracts forced upon utilities, with tax benefits being a boost to equity returns.

For carbon capture projects, however, tax credits are likely to be the sole means of support; as noted, carbon capture projects are selling a pollution control service of carbon abatement for which there is no private monetizable market value (apart from a few private voluntary carbon credit markets with low prices, limited volume, or both). There is very little precedent for successful scale-up of an industry (except for national defense) that has no commercial source of cash revenues and solely relies on federal support for its existence. One key challenge with CCS is the form of the incentive (non-cash corporate tax credits) used to support it.

Limited tax liability and high transactions costs for monetizing corporate tax credits reduce credits' effectiveness in supporting CCS projects

A tax credit (as opposed to deductions) is generally considered to be like a special currency earned by a project when it captures and sequesters CO_2. The tax credit though, is a non-convertible currency; a tax credit's sole commercial value is as a means of paying a project's federal tax bill. If a CCS project corporation (or the project's partners if the project entity is structured as a partnership for federal tax purposes) does not owe taxes in the first place (i.e., has no pre-credit federal tax liability), then a tax credit has no value to the project directly (or to its partners directly, if a partnership). Furthermore, tax credits, at least those prior to passage of the IRA, are not liquid since they cannot simply be sold for cash to an unrelated taxpayer.

[ll] In countries with nationally controlled electric grids the typical mechanism was a cash "feed-in tariff." In the UK, with a deregulated grid, a state-sponsored corporation garnered power to impose the cost of synthetic feed-in tariffs (called Contracts for Difference) directly onto ratepayers. As described herein, Canada has adopted a cash refundable investment tax credit. Notably, the U.S., for a brief period (2009-2012 for wind and 2009-2016 for solar) had cash-refundable tax credits in the §1603 grant-in-lieu of ITC program.

Few CCS projects in and of themselves are projected to have pre-credit federal tax liability for the first decade or more of their lives. This lack of taxable profits arises because these projects have low or no private market revenues, significant accelerated depreciation expense deductions, and large interest expense deductions on any outstanding debt. This does not mean CCS projects lack a viable business model or are too expensive; rather, it means that CCS projects are being paid, exclusively, with non-cash tax vouchers. In contrast, renewable projects that benefit from state-mandated power purchase agreements are paid a cash premium over market rates for spot, non-firm electricity. CCS projects can reliably earn revenues in the "currency" of non-cash tax credits, but the CCS projects may not be profitable enough for tax purposes to use the credits directly.

If a CCS project were consolidated into a large, profitable corporate owner's tax filing, the problem would be solved. However, most of the industrial, utility, and energy companies that would be the likely owners of a CCS project are not highly profitable from a federal tax perspective. **Table 2** illustrates this issue. Industrial sectors that emitted ~87 percent of U.S. stationary biogenic and anthropogenic GHGs in 2019 only earned about four percent of U.S. corporate federally taxable net income (totaling ~$70 billion in that year). The most extreme example is the utility industry with ~54% of U.S. emissions and one percent of its taxable income. To put the utility industry's ~$70 billion in perspective, similar taxable incomes were earned by modest sectors such as drug and grocery wholesalers ($71 billion) and "non-depository credit intermediation" ($64 billion).

Table 2

Federally taxable income and GHG emissions of U.S. major emitters, 2019

Major GHG Emitting Industries	Federally Taxable Income 2019 ($)		Stationary/Pipe GHG Emissions 2019 (metric tons CO_2e)
Oil and gas extraction	$	1,200,770	283,875,616
Petroleum and coal products manufacturing	$	34,840,173	236,074,000
Utilities	$	13,826,510	1,618,736,324
Pulp, paper, and paperboard mills	$	2,320,614	131,274,598
Basic chemical	$	11,223,246	127,678,000
Cement, concrete, lime, and gypsum product	$	2,240,951	102,830,025
Iron, steel mills, and steel product	$	3,014,802	66,000,000
Pipeline transportation	$	1,280,887	33,304,847
Total of all Taxable Major GHG Industries	**$**	**69,947,953**	**2,599,773,411**
Total of all Taxable Corporations	**$**	**1,733,277,148**	**2,986,530,194**
% of major GHG Emitters		**4.0%**	**87.0%**

If a CCS project organized as a partnership realizes that its natural owners (such as industrial companies or a clean energy developer) do not have a direct need for tax credits to reduce their corporate tax payments, the CCS project could find investor partners who do have "tax appetite" (need to reduce taxes using credits). The CCS project would then form a "tax equity partnership" that disproportionately flows through the tax credits to that new subgroup of partners with tax appetite.[mm] This practice utilizes special IRS rules that relate to allocation of losses, gains, and credits of such energy partnerships on a non-pro-rata basis in some years (a.k.a. "the partnership flip model").[60] The normal practice is for each partner to receive gains, losses, and credits in *direct proportion* to its percentage ownership in every single year. By contrast, in the partnership flip model (commonly referred to simply as a "tax equity deal") the partnership can choose to allocate gains, losses, and credits *disproportionately* year-by-year, as long as things even out eventually over the life of the partnership. Since tax credits arise early in a project's life (45Q is earned for 12 years, though a project could last 20-30 years), gains, losses and credits are allocated to partners with tax appetite (a.k.a. "tax investors") early on. After a period of years, the situation reverses, and the allocations shift heavily in favor of the parties without tax appetite (a.k.a. "cash investors) to even out the results.[nn]

The mechanism just described -- a tax equity partnership -- has historically been the tool of choice, or perhaps the tool of last resort, by which energy tax credits could be monetized. IRS regulations set forth minimum upfront investments that the tax equity investors are required to make for the IRS to "respect" the tax equity partnership allocations. This feature—advantageous to project sponsors—means that the tax equity mechanism produces money upfront (or at least before the tax in-service date) that could pay for project construction or repay temporary construction period financing. A key question for the implementation of the relevant provisions in the IRA, is the extent to which the five years of direct pay plus seven-years of transferability combined package can similarly pre-monetize 45Q tax credits to produce construction funding for CCS assets.

[mm] A partnership does not pay tax directly. Instead, the partnership allocates income, losses, and credits to its partners, and the partners combine the partnership-derived income, losses, and credits into their own tax returns.

[nn] Entering such partnerships creates a host of adverse knock-on tax consequences for pension funds, charitable endowments, sovereign wealth funds, and affluent individual investors, thereby diminishing the pool of potential tax equity investors and thus limiting the clean energy market expansion overall.

Project developers who monetize tax credits for cash investment by tax equity investors have historically received less than the full value of the credit

Tax credits have been monetized by the wind and solar industries with reasonable success because they are creditworthy, low-technology risk projects. As described above, the vehicle for monetization has been for tax equity investors acquiring partnership shares (or "membership interests" in case of limited liability corporations or LLCs) in an entity that owns and operates the clean energy asset (the developer). The partnership agreement between the developer and non-taxable partners (cash investors) and tax equity investor (tax investors) steers the bulk of tax credit benefits, all of which arise early in the project's life, to the tax investors.[oo]

Tax equity investors for such projects have historically been a limited universe, primarily made up of major investment and commercial banks. These financial institutions are interested in corporate clean energy tax credits because their firms' partnerships are highly profitable, can reasonably forecast future tax liabilities, and have little in the way of fixed asset depreciation to offset taxable income. However, the arcane partnership allocation schemes by which tax benefits are shifted from energy projects to such banks are cumbersome, and the total amount of banking profits that can benefit from tax credits is limited, both practically and by tax law. [pp]

Historically, the tax equity market has not been large enough to monetize 100% of the tax credits of wind and solar projects that arise each year, as well as a similarly sized but reportedly easier-to-transact volume of low-income housing and historic preservation tax credits. Given the relative shortage of tax equity investors, such financial entities prefer the least-risky deals and thus we have not been able to identify any significant tax equity deal for CCS prior to IRA.[61]

[oo] The IRS-approved mechanisms of temporally parsing cash and tax credit allocations between tax equity partners and the other partners are complex. Fundamentally, these special allocation regulations are simply a mechanism for selling tax credits without explicitly acknowledging doing so. See Treas. Reg. section 1.704-2(e) and Rev Proc. 2020-12 re §45Q https://www.irs.gov/pub/irs-drop/rp-20-12.pdf Also helpful is the following IRS publication: https://www.irs.gov/pub/irs-utl/allocations_of_tax_credits.pdf

[pp] As discussed later, only 75% of a company's pre-credit tax liability can be offset by Section 38 tax credits, a category of corporate tax credits that includes all the energy tax credits that are candidates for tax equity transactions.

In general, with a surplus of tax credit deals and paucity of tax equity investors, the tax equity investors can exercise market power, driving up the cost of funds. Bloomberg New Energy Finance attempted to estimate the size of the "tax equity haircut" in a 2010 paper.[qq] BNEF calculated that the cost to the Treasury to successfully stimulate 1MW of wind energy with a cash payment would be about 50% of the cost of accomplishing the same result with production tax credits.[rr,62]

Note that non-specialists often ask the following reasonable but difficult question, *"How many cents on the dollar does the project actually get when it monetizes its tax credit in a tax equity deal, and how big of a 'haircut' does 'Wall Street' give the project owner?"* Since tax equity partnership transactions are private with closely guarded transaction financial projections, however, no one can generate indisputable quantification of "the haircut". Since (prior to IRA) the credit could not be legally sold to the highest bidder in a straightforward manner, answering the question above required comparing the Net Present Value (at some theoretical economic discount rate of life-of-project yearly receipts to non-tax equity partners in a tax equity deal) vs. receipts to owners (assuming the tax credits were received as a non-taxable cash incentive payment by project with a conventional financial structure). This is the methodology that BNEF used in its 2010 analysis.

The reason one must look at the entire financing structure of a project (i.e., a tax equity structure vs. a conventional structure) to answer "how big is the haircut" is that expensive tax equity dollars are plugging the financing gap created by the absence of low-cost project debt. That low-cost project debt is missing because federal support provided in a non-cash form (tax credits) cannot be used to repay loans. Comparing debt and tax equity cost of funds, past and present, illustrates the impact of this expensive equity-for-debt substitution (note that since interest is tax deductible, but equity profit distributions are taxable, one must be careful to specify pre-tax versus after-tax costs of funds):

- A decade ago, long-term project debt typically yielded in the 5.5% range pre-tax)/3.6% after tax, with cost of tax equity being approximately 12-13% pre-tax equivalent (7.8-8.5% after tax @ 35% rates). So, using tax equity vs. debt was then driving up after tax funding cost by ~4-5% on the corresponding portion of the capital structure[63]; and
- Prior to recent Fed rate hikes, long-term project debt was in the 4% range pre-tax/3.16% after tax, and the cost of tax equity was around 8.2%-9.5% pre-tax

[qq] This citation dates from 2010, as no other public analyses of this problem are available (from reliable sources).

[rr] The 50% figure was calculated by averaging the 2005 to 2008 figures in Figure 6 (p. 5/9) of the cited article.

equivalent (6.5% to 7.5% after-tax @ 21% rates). So, after-tax funding, cost was still being driven up by ~4%.[ss]

Successfully meeting U.S. climate objectives requires major growth across a wide variety of decarbonization sectors, all which Congress has traditionally incentivized with non-cash corporate tax credits. There may ultimately emerge a far larger supply of energy tax credits than current tax equity investors can consume. In response, multiple approaches to reforming tax credits were proposed during consideration of the IRA (discussed below). If the particular new approaches (some direct pay, some transferability, for some investors) enacted in the IRA are not successful, then wind and solar may revert to the familiar, albeit complex and expensive, tax equity partnership structure (described above). If this occurs, it is very possible that newer, riskier decarbonization project classes such as CCS could be left behind.

Efficient financing of U.S. energy decarbonization through tax credits may be constrained because the growth in the supply of new credits may outpace the growth in demand for them, both within traditional tax equity investor classes and in whatever tax-benefit transfer marketplace emerges post-IRA

The absolute demand for corporate energy tax credits has been falling, or is at best stagnant, in recent years because of mounting sums of unused energy tax credits on the balance sheet of power and energy companies, the 14-point cut in corporate tax rates effective 2018 (from 35% to 21%), and the already low effective tax rates of key financial institutions. This fall in demand contrasts with the rise in tax credit supply because of IRA.

[ss] See https://www.projectfinance.law/publications/2021/june/tax-equity-snapshot/. Figures converted from pre-tax 6.5% and 7.5% (see text of interviews) by dividing by (1- prevailing corporate tax rate). For debt, spreads of 1.75% were used, cited in https://www.projectfinance.law/publications/2022/february/cost-of-capital-2022-outlook/, and added to mid-2021 10-year Treasury yields of 1.5% from Federal Reserve St. Louis at https://fred.stlouisfed.org/series/BAMLC0A4CBBBEY.

Overview of the existing and incremental supply of federal tax credits

The ability to execute U.S. clean energy goals in the absence of cash incentives depends upon the ability of corporations to productively utilize all the existing and new energy tax credits. The total "market" for the credits is simply based on the size of corporations' pre-credit federal tax bills, whether credits are used directly by a project owner, through a traditional tax equity partnership (or perhaps lease) transaction, or through the new transfer provisions featured in IRA.

Figures from the Office of Management and Budget show that prior to the passage of the CHIPS Act and IRA, estimated tax credit budget expenditures (i.e., taxes collection foregone via tax credits) would total $572 billion from 2022-2031.[64] The supply of tax credits then grew further with the CHIPS and Science Act (2022) adding $24 billion of high tech-oriented credits and IRA 2022 adding another $185 billion of decarbonization-related corporate tax credits that Congressional sources estimate would also be used over the same 2022-2031 time frame.[tt,65]

Therefore, these various tax credit programs are expected to cost the Treasury on average ~$781 billion annually over the next decade.[uu] Beyond the incentive tax credits, another major tax credit program is the corporate foreign tax credit. This provision of U.S. corporate tax law provides a credit against U.S. taxes for the payments that a corporation makes to foreign governments (up to the 21% U.S rate). The most recent figures (2018) show $105 billion of foreign tax credits for that single year.[66] Taken together and using the year 2018 as an example, the IRS showed $405 billion of total income tax before credits, $159 billion of total corporate tax credits and $245 billion of income tax after credits, implying that tax credits reduced U.S. tax payment by ~40%. Note, only 75% of corporate tax can be offset by Section 38 tax credits (including clean energy tax credits).

IRA triples the supply of energy specific tax credits that depend on corporate tax appetite by 2031

Figure 6 shows the aggregation of pre-IRA and IRA clean energy tax credit programs likely to rely heavily upon the tax equity market and/or the new tax credit monetization

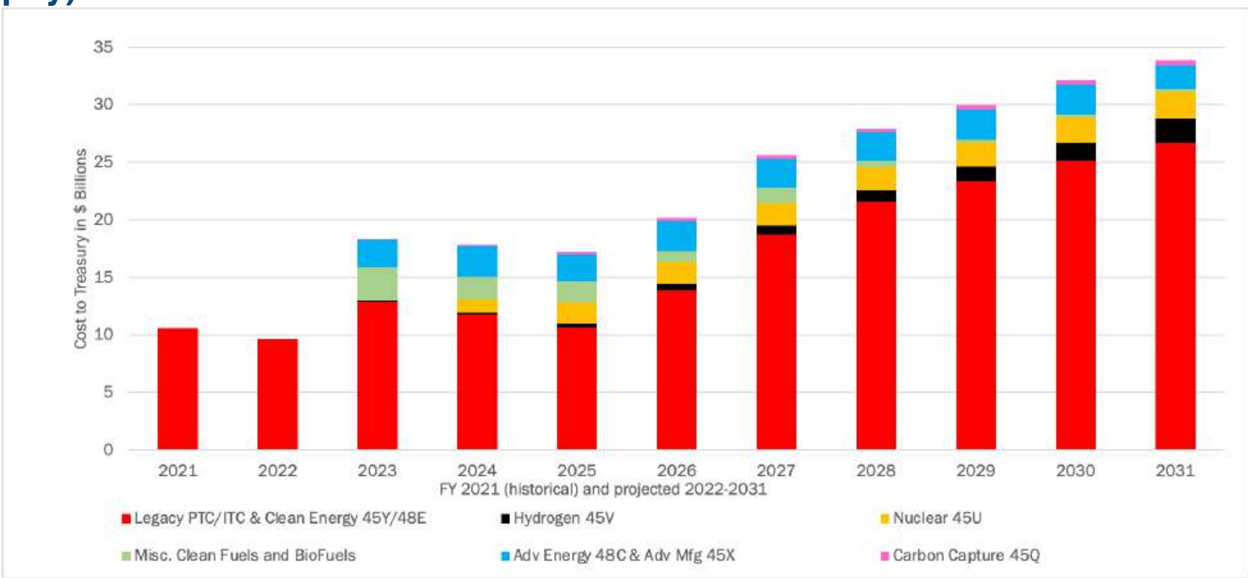
[tttt] This $185 billion figure is the 2023-2031 IRA clean energy corporate tax credit sum after subtracting estimates for credits claimed under special cash refund provisions and clean vehicle credits aimed towards individuals. See also following footnote.

[uu] The summation of $572 billion, $24 billion, and $185 billion is $781 billion.

option enacted in IRA.[vv] The chart entirely excludes JCT estimates of the portion of credits that would be paid out in cash as "direct pay" and that would not therefore place demand on the execution capacity of the traditional tax equity market or an emerging tax credit transfer market.[ww] The annual total of clean energy specific tax credits would increase to 3.4x today's levels from $10 billion (2021) to $34 billion (2031). Note that the dollar figures portrayed in **Figure 6** are estimated revenue impacts upon the Treasury/taxpayers estimated to be as opposed to net incentive benefits that ultimately reach the project sponsors.

Figure 6

Aggregation of U.S. Congress Joint Committee on Taxation scoring of pre-IRA and IRA energy related corporate tax credits (net of direct pay)



Size of corporate tax liabilities: the addressable market for tax equity or tax credit transfer

The prior discussion focused on the supply side of the tax credit market. This subsection focuses on the demand for tax credits by corporations.

[vv] The values are Joint Committee on Taxation (JCT) estimates of the year-by-year cost to Treasury, rather than amounts monetized in the tax equity market. Actual committed volumes of tax equity deals and the timing of partnership capital contributions are not publicly available.

[ww] Figure 6 was compiled from dozens of JCT and Congressional Research Service reports, many of which are contradictory, some of which are outdated. The authors of this study believe it to be accurate and have not seen any other attempts to do the same aggregation.

A concern is that the current tax equity investor universe will be unable to expand its current annual usage of energy tax credits (i.e., from $10 billion in 2021 to ~$34 billion in 2031). If the traditional tax equity market does not expand and corporate tax bills do not rise, the difference (e.g., $24 billion) would have to be transacted by the yet-to-be-developed tax credit transfer marketplace.

High level view of U.S. corporate taxable income, use of credits, and final tax payments

Table 3 below was developed from the most recent (2019) IRS estimates of U.S. corporate taxes. It shows total corporate taxable income of $1,733 billion, pre-credit tax liability of $383 billion, and taxes ultimately paid of $257 billion, implying usage of $125 billion of tax credits in 2019. Since, as discussed, only 75% of corporate tax can be offset by Section 38 tax credits (including clean energy tax credits), it is calculated that if every single taxpayer corporation had used such tax credits to offset 75% of its tax payments, another $161 billion of tax credits could theoretically be consumed. At present it appears that across the entire corporate taxpayer universe about 44% of the maximum tax credit capacity is now used. The open question is the extent to which tax credits generated in industries that have used most of their tax capacity (such as utilities that use 89% of the theoretical maximum) can successfully transfer credits to industries that use little of their theoretical maximum (such as real estate at 16% or wholesale trade at 22%).[67]

Where do “tax investors” fit into the overall investor universe for clean energy projects?

Investment bankers often categorize the possible investors/acquirors of complete or partial equity stakes as either “strategic investors” or "financial investors.” For projects that generate large amounts of tax credits, they add a third category of “tax investors.”

- **Strategic investors** in CCS are companies whose own operations could be decarbonized through ownership of a CCS project (such as oil refinery owner that could decarbonize its hydrogen units or FCCU), or whose expertise in operation of capital-intensive chemical processes might lead it to set up a new division running carbon capture facilities for others. However, given interest deductions, fast depreciation write-off expenses, volatile taxable income, industry-specific tax breaks, and generally low overall commodity operating margins, all of which already deeply cut the annual tax bills of these strategic investors, their remaining need for tax credits is small in most years.

Table 3

IRS Estimates of U.S. Corporate Income Taxes by Industry 2019 (in millions)[68]

Major Taxpaying Industries	Income Subject to Tax	Total Income Tax Before Credits	Total Income Tax	Implied Credit Use	75% of Total Income Tax Before Credits	"Addressable Remaining Market"	% of Cap Used
Educational services	$1,335	$281	$271	$10	$211	$201	5%
Mining	$6,003	$1,261	$547	$714	$945	$232	75%
Utilities	$13,827	$2,904	$968	$1,936	$2,178	$242	89%
Agriculture, forestry, fishing, hunting	$3,689	$775	$653	$121	$581	$460	21%
Arts, entertainment, recreation	$3,891	$817	$731	$86	$613	$526	14%
Other services	$3,915	$822	$764	$58	$617	$558	9%
Administrative & support and waste management & remediation services	$18,760	$3,940	$2,604	$1,335	$2,955	$1,619	45%
Real estate, rental, leasing	$17,472	$3,827	$3,379	$448	$2,870	$2,422	16%
Accommodation and food services	$28,554	$5,996	$4,274	$1,723	$4,497	$2,775	38%
Construction	$22,491	$4,736	$4,117	$619	$3,552	$2,933	17%
Health care and social assistance	$23,720	$4,981	$4,597	$384	$3,736	$3,352	10%
Transportation and warehousing	$25,542	$5,391	$4,955	$436	$4,043	$3,608	11%
Professional, scientific, technical services	$44,640	$9,771	$6,990	$2,781	$7,328	$4,547	38%
Computer and electronic product manufacturing	$110,441	$27,056	$15,419	$11,637	$20,292	$8,655	57%
Pharmaceutical and medicine	$98,270	$20,637	$13,958	$6,679	$15,477	$8,799	43%
Retail trade	$104,298	$22,104	$18,419	$3,684	$16,578	$12,894	22%
Management of companies (holding companies)	$227,531	$47,782	$25,020	$22,762	$35,836	$13,074	64%
Wholesale trade	$146,593	$32,651	$24,992	$7,659	$24,488	$16,829	31%
Information	$185,309	$38,915	$27,792	$11,123	$29,186	$18,063	38%
Finance and insurance	$344,068	$73,805	$57,460	$16,345	$55,354	$39,009	30%
Manufacturing	$511,640	$117,805	$68,599	$49,206	$88,354	$39,148	56%
Total returns of active corporations	**$1,733,277**	**$382,998**	**$257,130**	**$125,868**	**$287,249**	**$161,381**	**44%**

- **Financial investors** in CCS are entities like investment companies, pension funds, life insurance companies (on behalf of whole life policy holders), or sovereign wealth funds. Ordinarily, since these institutional investors are dominant players in U.S. stock and bond markets, they would be expected to be investors in CCS. However, they have no use for CCS-generated tax credits, since these entities pay no tax on stock and bond income and have no income to offset if they earn tax credits through direct or indirect ownership of clean energy projects.

- **Tax investors** are a currently thinly populated category essentially consisting mostly of major, sophisticated investment/commercial banks that have high profits and few physical depreciable assets, leading them to have a high federal tax bills (at least before taking account of tax-motivated transactions such as investing in clean energy projects that generate tax credits). However, for reasons discussed below, the total capacity of these tax investors to absorb more credits is inherently limited by the size of their pre-tax credit federal liabilities.

The following subsections discuss these limitations on tax appetite (i.e., the ability to utilize tax credits productively and reliably on the part of a taxpayer) for selected major industries.[xx]

Major financial institutions have little room to further reduce their tax liability via tax equity transactions

U.S. clean energy could not have scaled up without Wall Street. Major U.S. financial institutions, primarily entities that combine commercial banking, investment banking, securities and commodities trading, and securities brokerage, have been the backbone of the tax equity market.

IRS 2019 reports show that the four largest financial industry sectors that participate in the tax equity market—commercial banks, investment banks, securities brokerage, and life insurance companies—paid a total of $16 billion of federal corporate income taxes.[69] This result is consistent with the Federal Reserve's 2019-2021 "National Income Accounts of the United States" for companies categorized as U.S. private depositaries, i.e., commercial banks, life insurance companies, and securities brokers. The Federal Reserve data reported taxes for these three sectors were $13.0 billion paid in 2019, a refund of $8.1 billion in 2020, and a refund of $7.4 billion in 2021. Obviously 2020 and 2021 were affected by COVID-affected years, but the $13 billion in 2019 is like the IRS data of $16 billion in 2018.[70]

Above and beyond the basic issues of adequate tax appetite, few entities other than financial firms supported by a bench of tax attorneys and accountants have been able to navigate the specific rules of each clean energy tax credit program. For instance, to earn a wind PTC, the taxpayer must both own and operate the wind turbine – so a simple

[xx] Given confidentiality of corporate tax returns, it is challenging to offer precise and comprehensive analysis of the limitations of the tax equity market and its potential for growth.

leasing transaction is ruled out. A solar ITC can be "clawed back" (i.e., the tax credit demanded back by the IRS), in whole or part, over the first five years of solar farm operation if the facility changes ownership – even in case of involuntary bankruptcy. These difficulties notwithstanding, without the support of these institutions, the renewable energy industry would not have successfully scaled up. Wall Street's tax appetite is not, however, infinite; that constraint, unless alleviated, may curtail additional clean energy scale-up, especially CCS.

In some years, certain major banks pay little or no federal tax, which means that their corporate tax managers must use caution in commitments to acquire tax credits. To illustrate that point, Bank of America had $34 billion in book profits in 2021; at a full 21% U.S. federal corporate tax rate, it would theoretically have paid $7.14 billion in federal taxes that year. Bank of America actually paid a much smaller $2.1 billion of U.S. federal tax (an effective 6.2% federal tax rate). The smaller $2.1 billion actual payment reflects in large part the benefit of using $3.8 billion of energy and affordable housing credits.[71] This suggests that Bank of America does not have much additional tax liability that could be offset by acquisition of incremental volumes of tax credits. While there is no issue with banks minimizing their tax burden in exchange for supporting clean energy and affordable housing, it is important to remember that the capacity to do so is not inexhaustible.

Looking at a longer time frame for several major banks, the picture is similar: not much room to grow tax credit use by the traditional leaders. An analysis of Securities and Exchange Commission (SEC) filings for JPMorgan Chase, Bank of America, and Wells Fargo for 2019-2021 (inclusive) shows that these three financial firms, all among the top tax equity investors, averaged a combined $8.1 billion per year of tax credits (energy and affordable housing) with remaining U.S. federal taxes paid of $9.2 billion per year (see **Table 4).** The three averaged a federal tax rate of 9.8% (percentage of pre-tax income).[yy] Considering the regulation limiting use of General Business Credits to 75% of pre-credit liability, one could estimate that the three firms together had room to consume a few billion more dollars a year of tax credits (probably less because the tax credit accounting for annual financial reports and tax returns can diverge significantly).

[yy] Note that the situation for international banks is complex, because international earnings contribute to total pre-tax profits; but bulk of taxes upon those internationally generated profits is paid to foreign governments, with the U.S. properly granting a credit against U.S. taxes for the foreign taxes paid. That is, if a bank earned half its profits in a non-U.S. country that also had a 21% tax rate and earned a credit for those taxes paid, it would then appear to a casual analyst that the bank was only paying 10.5% federal taxes.

Table 4

Federal Tax Liability of Top Tax Equity Investors (2019-2021, in billions).[72,73,74]

Top Tax Equity Bank	Book Income before Income Tax Expense	Benefits from Tax Credits (energy and affordable housing)	Actual Federal Tax Liability (after using tax credits)	Federal Tax as % of Book Income before Income Tax Expense
JPMorgan Chase	$46.7	$3.2	$4.5	9.7%
Bank of America	$28.6	$3.0	$1.8	6.4%
Wells Fargo	$19.1	$1.8	$2.9	15.1%
Total	$94.4	$8.1	$9.2	9.8%

Data from the 2021 annual report of each company.[zz]

Other factors suppressing growth of tax appetite by Wall Street

The remaining annual $9.2 billion of federal taxes detailed above *cannot* be taken as an indication that these large banks could or would increase their annual uptake of tax credits for three reasons beyond the 75% limit described above. [75]

First, firms exercise caution in making tax equity investments because profits, and thus tax liability, can ebb and flow from year to year. Indeed, for this reason, representatives from Capital One and US Bank, in a 2020 interview, recommended that firms be allowed to carry back tax credits for up to five years.[76] IRA went part way towards this request by extending the carryback period for energy credits to three years (previously it was set to one year).[77]

Second, firms may be hesitant about the public perceptions and policy responses of dropping tax liability too low.[aaa]

Third, tax equity partnership transactions or possible contracts to acquire transferable tax credits are long-term transactions that require tax investors to feel confident that their

[zz] Note that the cited figures are far from exact, and accounting treatment of energy tax equity flip partnerships is evolving (see FASB Exposure Draft ”Topic 323” of August 22, 2022). Currently, most banks account for LIHTC housing tax credits and energy tax credits differently. JPMC changed its accounting for energy tax credit deals in 2021 and restated 2020 and 2019 (generally reducing the stated impact of tax credits by approximately 1% of book net income in the latter two years. The specific balance sheet, contingent liability, income, and expense of energy tax credits are typically lumped in with “other income”, “other expense”, etc., as is allowable.

[aaa] Personal communication with senior tax equity bankers, May 17, 2022.

ability to successfully use credits would not be harmed by broad changes in tax legislation. There are two ongoing "minimum tax" developments that provide examples of potential policy changes that may erode this confidence:

- On the international front, the Treasury Department recently led negotiations with 136 countries on a global minimum corporate tax rate of 15% in response to successful efforts by corporations to reduce their tax liability.[78] It is not clear how U.S.-generated clean energy tax credits will be considered by non-U.S. tax authorities.
- On the domestic front, the IRA also includes a 15% corporate Alternative Minimum Tax (AMT) for corporations with at least $1 billion in adjusted financial statement income.[79] The IRA "held clean energy tax credits harmless" by allowing these and other credits that collectively fall into the category of the General Business Credit (IRC §38) to be applied to reduce either regular taxes or AMT taxes, which appears to be at least a neutral development. JCT estimated that the final IRA minimum tax provisions would raise an average of $25 billion per year from these large companies.[bbb] That is approximately a seven percent overall increase in corporate taxes compared to the $372 billion of federal corporate income tax revenue in 2021.[80] Given these new policies, it is possible that higher taxes on the largest corporations, combined with preservation of the ability to use clean energy tax credits to reduce those higher taxes, may somewhat increase corporate tax appetite for clean energy tax credits. A University of North Carolina Tax Policy Institute study identified companies whose tax bills they expected to rise the most. Berkshire Hathaway and Amazon made up approximately one third of the expected increased federal corporate income tax receipts.[81]

Utilities, oil & gas, and high-tech firms also have little room to absorb more tax credits

While the largest companies within the utility, oil and gas and high-tech sectors could, given their book profits, be expected to be viable entities for absorbing an expanding supply of tax credits, their capacity is relatively limited. Each of these industries is examined in turn.

Because they are significant owners of wind and solar assets, utilities (and independent power producers) would appear to be likely candidates to reduce their corporate tax bills

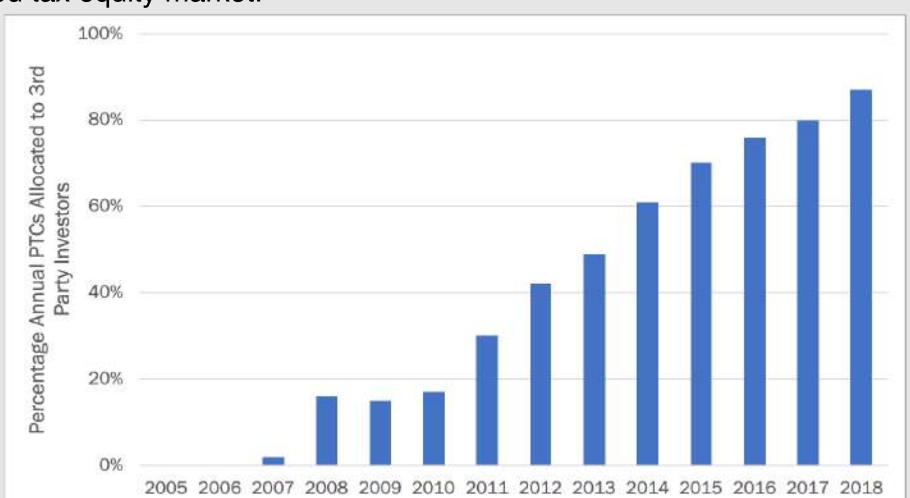
[bbb] See JCT's JCX-18-22 Subtitle A, total of $222 billion revenue over 9 years 2023-2031 inclusive.

by using their earned tax credits.[82] This strategy would seemingly extend to newly eligible decarbonization infrastructure as well. Utility holding companies in past years, however, have aggressively pursued generation of tax credits, so much so, that they now have material quantities of unused tax credits accumulating on their balance sheets that are being carried forward into the future. This can be seen anecdotally by examining individual corporate financial reports and appears to be borne out by the IRS 2019 figures cited in **Table 3** showing that utilities appear to be consuming 89% of their theoretical maximum tax credit usage amount. Many have accumulated billions of dollars of tax assets, which are the combined value of unused tax credits and net operating losses (for tax purposes, not book net income). An example is seen in **Box 2**.

Box 2

Running out of steam: the inability of a utility to make timely internal use of energy tax credits

NextEra (NYSE: NEE) is a utility holding company whose main operating subsidiaries are (i) the regulated utility Florida Power and Light (FPL) and (ii) the unregulated renewable power development company NextEra Energy Resources (NEER). For U.S. tax purposes the NEE's two subsidiaries are combined (or "tax consolidated). NEER's wind and solar tax credits can be used to offset taxable profits of FPL when calculating NEE's consolidated federal tax bill. By 2021 NEER had accumulated an extraordinary $4.64 billion of energy tax credit carryforwards, growing at a rate of $800 million per year.[83] The graph below, recreated from the original source, shows the rising percentage of annual PTCs that NEE has had to allocate to 3rd party investors (presumably in tax equity flip transactions)—adding ever more tax credit supply to the already over-supplied tax equity market.[84]



Moving to the oil and gas sector, that industry does not seem likely as a destination for a large proportion for new tax credits earned by other companies' projects, especially given the inherent volatility of prices in fossil fuel commodities markets.[85] This revenue volatility produces large swings in oil and gas companies' taxable income, with corresponding swings in ability to efficiently utilize tax credits. Moreover, oil and gas firms have large tax-deductible depreciation and depletion expense, which further reduces pre-credit tax liabilities that would give oil and gas firms appetite to participate in the clean energy tax credit market.

Table 5 shows that in 2021, the listed companies, often called the top five in the U.S., earned $75.3 billion in book profit before tax (worldwide). Their total U.S. federal taxes paid, however, were just $5 billion, or an effective tax rate of seven percent. To be clear, this calculated tax rate is low because these companies can credit taxes paid abroad against U.S. taxes. The fact remains, however, that these representative firms have not recently had significant amounts of U.S. income tax to shelter in the context of a large increase in the U.S. tax credit market. Some equity analysts have, however, advised that with NYMEX daily oil prices averaging $95/bbl in 2022, large U.S. oil and gas companies may be able to substantially consume the backlog of losses and excess credits accumulated in recent years, which would improve the situation for as long as high oil prices persist.

Table 5

Income and Taxes, Top U.S. Domiciled Oil Companies (2021, in millions) [86,87,88,89,90]

	Book 2021 Profit before Tax	Tax at 21% Statutory Rate	Actual Total Tax Paid (US, local, and Foreign	US Tax Paid Current and Deferred	Federal Tax as % Book
ExxonMobil	$ 31,324	$ 6,578	$ 7,636	$ 1,132	3.6%
Chevron	$ 21,639	$ 4,544	$ 5,950	$ 1,178	5%
Conoco Phillips	$ 12,712	$ 2,670	$ 4,633	$ 1,193	9%
Occidental Petroleum	$ 3,705	$ 778	$ 915	$ 364	10%
EOG Resources	$ 5,933	$ 1,246	$ 1,269	$ 1,162	20%
Total	**$ 75,313**	**$ 15,816**	**$ 20,403**	**$ 5,029**	**7%**

Finally, the largest high-tech companies typically have access to large quantities of R&D tax credits and significantly accelerated depreciation deductions on some assets; in some cases, high tech firms' multinational status enables them to minimize their tax liability.

The total profit before taxes in the top five tech companies was $316 billion; their federal tax paid was only $18 billion -- 6 percent of their profit (**Table 6**).

Table 6

Income and Taxes, Top U.S. Tech Companies (2021, in millions).[91,92,93,94,95]

	Book 2021 Profit before Tax	Tax at 21% Statutory Rate	Actual Total Tax Paid (US, local, and Foreign	US Federal Tax Paid Current and Deferred	Federal Tax as % Book
Apple	$ 109,207	$ 22,933	$ 14,527	$ 1,081	1%
Microsoft	$ 71,102	$ 14,931	$ 9,831	$ 3,310	5%
Alphabet	$ 90,734	$ 19,054	$ 14,701	$ 10,995	12%
Amazon	$ 38,151	$ 8,012	$ 4,791	$ 2,284	6%
Tesla	$ 6,343	$ 1,332	$ 699	$ 0	0%
Total	**$ 315,537**	**$ 66,263**	**$ 44,549**	**$ 17,670**	**6%**

Possible approaches to making energy tax credits for CCS more valuable

Before turning to recommendations based upon the new tax credit utilization provisions of IRA, it is helpful to review the four principal recommendations made by experts to solve the issue of the lack of the demand for energy tax credits (a.k.a. "lack of tax appetite" in market parlance) among investors and the corresponding difficulty of using energy tax credits.

Given the status quo prior to the passage of IRA, there were fundamentally four possible means of enhancing the efficient monetization of clean energy tax credits, thereby ensuring that a $1 tax credit cost to the taxpayers generated a corresponding $1 (or close to $1) of benefit to decarbonization projects.

As IRA was being drafted, the first and best option from the point of view of clean energy projects would have been to make to clean energy tax credits, including the 45Q carbon sequestration tax credit, fully cash refundable, for all investors (except individual taxpayers) in clean energy projects, for all clean energy tax credit types, for the full claiming period of each credit. A second, less comprehensive, option was to allow cash refundability for some investors (still excluding individual taxpayers); some tax credit types; or for part of the claiming period. A third option was to make legal the straightforward sale or "transferability" of tax credits from the credit generator to a corporate taxpayer 3rd party, replacing the more cumbersome tax equity partnership model. A fourth option would have been to change tax law for individual investors/taxpayers to allow them to successfully participate in clean energy partnerships.

The IRA ultimately used a mix of options two and three: direct pay for some non-individual investors/some projects/some of the time, and an easing of transferability rules. Below we comment on the general benefits and drawbacks of these mechanisms, the changes made in IRA, and improvements that would extend the gains in efficient tax credit monetization made in IRA.

Approach 1: cash refundability of tax credits ("direct pay") for all non-individual investors/projects

This was roughly the path taken in the §1603 program discussed earlier, with corporate taxpayer investors able to convert PTC-type credits to ITCs and then to convert the ITCs to cash grants.[ccc] This option was not selected in IRA.

A full direct pay option would have helped CCS projects to obtain the full value of the credit directly from the United States government. Projects would not be uncertain about the future worth of tax credits. Unlike monetization schemes involving private counterparties, projects (and their bankers) would not have concerns about the financial ability of the United States to perform. Studies comparing the effectiveness of tax credits to cash subsidies have found that a direct payment to a project developer would produce almost twice the project investment as the same amount of subsidy provided in the form of a tax credit.[96,97] Direct pay for all non-individual investors will help three different categories of project owners/partners:

- Project investors who are legally taxpayers but earn tax credits that they are not practically able to use (because of limited generation of federally taxable net income);
- Project owners who are legally non-taxpayers (municipals, tribes, cooperatives, TVA) and have never been able to earn tax credits at all; and
- Investor entities who are *normally* non-taxpayers, *can* earn tax credits by being indirect partners in an energy project, but are snared in other tax regulations that

[ccc] Congress created the Section 1603 grant program as part of the American Recovery and Reinvestment Act of 2009 (ARRA; P.L. 111-5).

make the credits difficult to use. Pension funds and charitable endowments are examples of such entities, with a more detailed description below.

There has been an emerging, but not universal, consensus that a direct pay option for CCS is needed, an option that was included in several proposed statutes, including the Build Back Better (BBB) legislation, the Clean Energy for America Act, the CCUS Tax Credit Amendment Act, the GREEN Act, and the ACCESS 45Q Act.[98,99,100,101,102,103]

Approach 2: direct pay for some investors, for some credits, for a limited period

This option was implemented in IRA. Some non-corporate investors (governmental, tribal, and electric cooperative) will have direct-pay treatment for virtually all energy credits, for the life of the credit. Finally, corporate investors will have direct-pay treatment for just the first five years for only three types of energy credits, including 45Q.

Extending direct pay to *all* non-individual investors was ultimately infeasible as IRA was drafted. The principal sticking point was the perception that direct pay for all investors would constitute excessive *corporate* largesse. However, Congress did find feasible implementing direct pay for some, but not all, *non-corporate* owners of CCS projects. The universe of *non-corporate* entities that make significant investments in the energy/utility financial markets or as direct project owners, but that have not traditionally been able to directly use tax credits include two broad groups. First are non-taxpaying governmental/co-op investors, and second are pension funds and charitable endowments. IRA includes most of the former in life-of-credit direct pay for all credits, but it has not addressed the latter (i.e., pension funds and charitable endowments). Congress also found the case for three relatively new industries to be compelling enough to permit five years of direct pay for corporate investors (45Q, the new 45V hydrogen credit, and the new 45X advanced manufacturing credit).

<u>Non-taxpaying governmental/co-op investors</u>: Candidates that were authorized for “direct pay treatment” for the full claiming period for all clean energy tax credits are certain governmental and non-profit entities that are allowed to conduct energy-related “trade or business ventures” without paying federal taxes; this is a relatively non-controversial option. States and local government entities are constitutionally exempt from paying

federal taxes; so too is the Tennessee Valley Authority.[ddd] In the aggregate federal and state and local power sales account for 16% of U.S. electricity sales.[104] Rural electric cooperatives also play a major role in the power sector, providing approximately 13% of U.S. electricity.[105] It should be noted that agricultural cooperatives that directly own GHG emitting plants in the fertilizer and oil refining sector, such as the Midwest-based CHS Inc., appear to be excluded from direct pay eligibility in IRA.

Pension funds and charitable endowments: The second group, tax-exempt but not afforded life-of-credit direct pay, is made up of pension funds and charitable endowments that *are not* themselves taxable corporations; but they are forced for tax compliance reasons to hold interests in “trade or business” partnerships (such as clean energy project partnership interests) in special purpose entities that *are* corporations. These special tax-paying corporations are called “blocker corporations” (origin of term explained in **Box 3**). Allowing life-of-credit direct pay for pension fund- and charitable foundation-owned “blocker corporations” would remove a substantial barrier to institutional investor participation in the to clean energy market.

Pension funds alone owned $6 trillion of U.S. stocks at the end of 2020.[106] The top 50 charitable foundations reportedly own $229 billion of financial assets, and the top 10 university endowments own approximately $245 billion of financial assets.[107,108] Turning trapped tax credits into cashflow via life-of-project direct pay would make it easier and more remunerative for this large, tax-exempt, non-corporate, investor pool to be efficiently mobilized for clean energy investing of all types, CCS included. If nothing else, so doing could be argued for sake of consistency: if a Texas governmentally owned CCS project should be eligible for direct pay, why not if owned (albeit indirectly via a blocker) by the Teacher Retirement System of Texas (assets ~$200 billion) or the Texas A&M University endowment (assets $17 billion).

[ddd] The IRA seems to have included TVA but left out the four federal Power Marketing Administrations (BPA, SEPA, SWAPA, and WAPA).

Box 3

Pension funds & charitable foundations: difficulties with clean energy tax credits

The origin of the energy tax credit utilization problem for these sophisticated investors, many of whom are strongly motivated to support the clean energy transition with the investment dollars, relates to Congressional efforts to prevent income generated by partnerships owned (in whole or part) by pension funds, charitable endowments, and sovereign wealth funds from entirely escaping tax payments. This is of great importance, because a large portion of new energy project assets are owned by partnerships, and current law greatly discourages these investors from being involved in such investments. The background of current law is:

- For individual and corporate investors in corporate stocks, profits are taxed *twice* by the federal government. First, the corporation pays corporate income tax; and then the investor pays taxes on dividends.[eee]
- For individuals and corporate investors in partnerships carrying out a U.S. trade or business, profits are *taxed only once* by the federal government. The partnership is not itself a taxpayer: rather, it "flows through" profits and losses to its partners who pay the tax.
- For pension fund and charitable endowments investing in publicly traded corporate stocks, profits are *taxed only once*. The publicly traded corporations pay federal tax; but pursuant to a variety of different rules the pension fund and charitable investors do not pay federal income tax. I.e., if the California Public Retirement System owns Microsoft stock, Microsoft pays corporate income taxes, but CALPERS does not also pay tax on dividends received from Microsoft.
- If pension funds or charitable endowments were to directly hold partnership interests in U.S. trades or businesses, *profits would never be taxed at any level* by the federal government. The partnership would not pay tax, and these tax-exempt investors would not pay tax on profits "flowed through" to them either. To discourage this possible tax avoidance, several different tax law provisions establish severe financial penalties for direct ownership of partnership interests in a trade or business by these investors. To avoid the penalties, these investors are forced to create special taxpaying private corporations -- blocker corporations -- for the sole purpose of holding their ownership stakes in a U.S. trade or business partnership. [109] The "blocker" name arose because structure "blocks" or protects the non-taxpaying investor from tax penalties attendant to such an investor conducting a trade or business venture.[110] The problem is that clean energy tax credits that flow into the blocker corporation may simply be trapped, unusable, if – as may often be the cases for CCS partnerships--the clean energy partnership generates little or any taxable income.

Corporate investors in projects earning 45Q, 45V, or 45X tax credits: As mentioned above, Congress made a limited authorization of corporations to obtain direct pay treatment for these three tax credits for the first five years of a project's life, reverting to transferability/tax credit sale for years 6-12 (see Option 3 below). Since many CCS projects will earn no economic revenues--whether cash or non-cash--from any source other than federal incentives, this leaves potential investors in uncertainty about sufficiency of year 6-12 45Q tax credit sales proceeds to defray operations and maintenance costs, fuel expense, sequestration expense, mortgage payments, and returns to equity. Since the market price for $1 of 45Q tax credits in 2030 is unknown (for a project started in 2022 with three years of construction time plus five years of direct pay), an investor and project lenders could be justifiably concerned that that the 2030 future tax credit price will not be high enough to cover O&M, fuel, sequestration, debt service, and a return on equity. (Presumably, without a known sales price for tax credits, it would be difficult to obtain meaningful amounts of debt secured by those year 6-12.) Some commentators suggest that projects will gravitate to the traditional tax equity market bank/investment bank investors to obtain a package price for the five years of direct pay and seven years of transferability. No doubt such deals will be struck with that limited investor group, but those investors were already the mainstay of the tax equity market before the direct pay and transferability provisions of IRA; in such a case no real extra market capacity for 45Q will have resulted.

Approach 3: tax credit transferability

Making it possible simply to buy and sell clean energy corporate tax credits, as implemented for most production and investment clean energy credits in IRA, should reduce transactions costs but does not inherently increase total corporate demand for tax credits. Hopefully, some additional market participation will arise in the future from smaller corporations that, though lacking the sophistication to be operating partners in a clean energy project (as is required under the pre-IRA tax equity partnerships structure for PTCs), may still possess the financial credentials to be reliable transferees (in the post-IRA environment).

As to CCS, transferability is an improvement on the pre-IRA transfer regime. Under pre-IRA law, CCS projects could assign 45Q credits from the tax-owner of the capture facility to the party that sequesters the CO_2 underground; but it had never been clear how many

[eee] Simplification. There are certain exclusions for dividends received by one corporation from a second corporation in which the first corporation owns a substantial interest.

geologic sequestration enterprises would earn enough taxable profits to use the credits. The new ability to transfer §45Q tax credits to any corporate taxpayer, as set forth in IRA, is a vastly improved formulation of transferability. As mentioned above (in option two), the uncertainty as to the future price at which tax credits can be sold may ultimately limit the utility of tax credit sales/transfers for pollution control-oriented CCS projects that have little or no market-based revenues and are ~100% dependent upon tax credit sales revenues.

Approach 4: allow individual investors to support clean energy projects

Current tax law, specifically a set of provisions that apply only to individual taxpayers regarding "passive losses" and "passive credits," are a major blockage of capital, keeping individuals from putting their investment dollars to work in decarbonization projects, including CCS. Changing these passive loss/credit rules would greatly increase the total addressable market for energy tax credits, since individuals pay most federal taxes (large appetite) and directly own the bulk of investment securities (large wealth). The IRA did not include any updates on this front.

Since the 1984 tax reform legislation, Congress has distinguished between "passive" losses (and credits) generated by partnerships in which the individual has virtually no real involvement, vs. "active" losses (and credits) from an individual's share of losses in a business where the individual was materially involved.[111] As such, for tax purposes, activities are grouped as either passive or active activities. [fff,ggg] The passive activity rules limit an individual taxpayer's (i.e., non-corporate taxpayer) ability to use passive activity credits and losses to reduce tax payments on active income.

Passive credits and losses are those earned in a partnership for which the investor does not have active material participation (i.e., the individual is a passive investor).[112] The IRS promulgates seven tests to determine material participation, where if any criteria are met, then the resulting income would be deemed active.[113] Income from all passive and active activities are aggregated and treated the same; this cannot, however, be said for losses. Losses and tax credits tied to passive activities can only be used to offset passive income,

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[fff] The term passive activity means any activity, (A) which involves conduct of any trade or business, and (B) in which the taxpayer does not materially participate.

[ggg] It is important to note that portfolio income, which is comprised of interest, dividends, and capital gains, are treated separately, and are expressly *not* considered passive income under 26 U.S. Code §469(e)(1).

i.e., passive losses cannot be used to shelter wage or portfolio income. If a taxpayer's passive losses exceed passive income for a given year, these losses would be carried forward to be deducted from future years' taxable net income from passive activities (if any). Similarly, if no taxes are owed(pre-credit), then passive credits are also carried forward to be credited against future years taxes owed (if any).

The losses and credits generated in clean energy partnership such as CCS partnerships could represent an investment motivation for individual investors if an exception to passive loss rules were made for decarbonization investments (subject to regulatory definition). There are already such exceptions in law, including an exception for "professional real estate investors" and for losses associated with working interests in oil and gas properties held by a general partner. U.S. individual investors direct own $26 trillion of stocks, and the total rises to $41 trillion if individuals' stock mutual fund holdings are included. The figure rose by $6.8 trillion between 2019 and 2020 (including paper gains).[114]

Policy recommendations

The demand for tax credits, whether garnered through direct ownership by a corporation, through a tax equity partnership, or through new transferability provisions, is inherently limited and, if anything, has been shrinking in real terms; this has been exacerbated by corporate income tax cuts (2018) and pandemic related losses (2020-2021) that have resulted in large accumulations of unused/unusable corporate net operating losses and excess credits carried forward.

At the same time the supply for clean energy tax credits, because of the almost exclusive reliance upon credits to incentivize U.S. clean energy investments in the absence of a carbon tax, is expected to more than triple over coming years because of the passage of the IRA. This supply increase will necessitate an expansion of the demand for such credits from entities that have traditionally not participated in monetizing clean energy tax credits. This is of principal importance to ensure the enterprise of not only CCS, but all clean energy projects are successful as intended.

It is possible that the burgeoning supply of clean energy tax credits may be mitigated by the AMT provisions in the IRA to the extent that these AMT provisions materially increase pre-credit federal tax liabilities among the largest corporations. The AMT provisions are forecast to raise corporate tax receipts by ~seven percent. Further, demand for energy tax credits could be boosted by well-implemented, clear transferability rules that could modestly raise the participation level of corporations that can financially make good use of tax credits but have hitherto been reluctant to be exposed to the complexities of traditional tax equity partnerships. Finally, it should be noted that the tax credit supply growth would have been even greater had municipals, co-ops, tribes, and federal entities earning tax credits been given direct pay authorization.

Finally, while the IRA increased the demand base for tax credits, two significant sets of investors have been left with little or no ability to put their capital at work in tax-credit supported decarbonization projects:

- Tax-exempt pension funds and charitable institutions investors who own many trillions of dollars of U.S. stocks but must hold clean energy partnerships in blocker corporations; and
- Individual investors who own directly $26 trillion of stocks ($41 trillion if mutual fund holdings are included).

Recommendation 2A: The IRS should ensure that the new regulations required to implement the 45Q direct pay and transferability provisions of IRA are designed in a manner that will be conducive to bringing a broader range of new buyers into the market.

There are two implementation issues that warrant special attention from the IRS.[hhh] First, in practice, the transferees (tax credit buyers) are not likely to pay full value of 100 cents on the dollar to the transferors (tax owners who cannot use credits themselves) unless they can mitigate the risk of paying for non-existent credits and against recapture of credits. Credits could turn out to be non-existent, among other reasons, if: (i) a project transfers a full $85/metric ton 45Q but was only entitled to $17/metric ton because it failed to meet the prevailing wage and apprenticeship requirements of the IRA; or (ii) the project fails to properly document its contract (including compliance with various EPA regulations) for geologic sequestration in a year. Other risks could include recapture if sequestered CO_2 is released within three years of its injection.[115]

[hhh] On October 5, 2022, the IRS issued six notices asking for comments on different aspects of extensions and enhancements of energy tax benefits in the IRA. Notice 2022-50: Request for Comments on Elective Payment of Applicable Credits and Transfer of Certain Credits pertains to the implementation issues described herewith.

A second group of arcane but vitally important implementation issues revolve around who owns and receives the credits that can be transferred, and/or the funds arising from a direct pay option. Ordinarily a tax credit flows directly to members in an LLC or partners in a partnership. The IRA, in §6417(c)(C), allows a taxpayer to make the election for direct pay, but an LLC is not a taxpayer, so this implies that individual partners make the election and receive the direct pay funds. This makes it difficult to leverage these dollars in a debt transaction. On the other hand, the transferability language (§6418(c)(1)) seems to imply that the partnership itself makes the decision to transfer tax credits (i.e., in years 6-12 of 45Q) on behalf of all partners.

Finally, according to the analysis by a law firm, issues could emerge if different owner types are comingled in a partnership, "It appears that if a partnership has an 'applicable entity' (e.g., a tax-exempt entity) and a regular taxpayer, that the partnership may not qualify for either transferability or direct pay."[116] The relevant point extrapolated here is that the IRS should do its utmost to make transferability and direct pay provisions easy to understand and to efficiently monetize in the context of normal clean energy project structures.

Recommendation 2B: Congress should consider expanding the pool of eligible entities able to make use of all clean energy tax credits.

Two major classes of investors – the non-taxpaying institutional investors (pension fund and, charitable endowments/foundations) and individual investors – have no straightforward route to benefit from clean energy tax credits. And yet these two groups directly or indirectly (via mutual funds) own roughly $50 trillion of U.S. stocks. The stock of assets owned is large, but these groups, at their discretion, also commit impressive volumes of new funds to equity markets each year. In the long run, it is difficult to envision successful U.S. decarbonization without bringing this massive pool of capital to bear on investments in GHG mitigation options.

A future Congress should first consider allowing direct pay for the special class of corporations, "blocker corporations" in which pension funds and charitable endowments/foundations must hold their interests in partnerships and LLCs. There is little likely loss of revenue to the Treasury from tax avoidance, especially in the case of carbon capture projects that may have little or no taxable revenue.

Second, easing the passive activity loss and tax credit limitations of current tax law would result in a significant increase in the market for clean energy tax credits. Individual taxpayers own directly $26 trillion of stocks ($41 trillion including mutual funds). Many individuals who have strong motivation to support decarbonization projects, have great personal wealth managed in family offices or in privately held family corporations. Congress should consider making it easier for these individuals to be part of the climate solution.

THEME 3: CRITICAL DATA AND KNOWLEDGE EXIST ON CAPTURE AND GEOLOGIC STORAGE; INCREASING ITS AVAILABILITY AND ACCESSIBILITY WOULD ACCELERATE COMMERCIALIZATION

Improve the availability and usability of data from publicly funded projects

Overview

Detailed data and knowledge about carbon capture technology and geologic storage characterization, cultivated over decades through federally funded research programs, represent a valuable informational resource that could be used to accelerate CCS development. Follow-on project developers and investors could learn from past experiences to inform their strategies about potential opportunities, taking advantage of innovation and knowledge spillover effects. Yet not all this information is readily accessible in a form that would-be CCS developers could use to inform critical investment and design decisions.

On the one hand some of these data limitations can trace their origins to the federal government's desire to help private sector grantees protect trade secrets, technical data, and intellectual property (IP) created using mixed private and public funds. From the perspective of DOE, retaining rights to technical data and encouraging a grantee to patent inventions created under a funding agreement is a construct that is intended to motivate the creation of new knowledge, rewarding efforts for first movers, and offering a pathway to eventual - though in some cases narrow - public disclosure.

On the other hand, there may be instances where wider dissemination of certain data, and the associated experiences could help accelerate the scale-up of CCS. Considering the imperative to move quickly to scale up CCS nationally, while honoring private sector constraints, will require a careful balance by the DOE. This is a management task of DOE contracting officers who oversee the performance of private sector parties that have entered into CCS-related federal cost-sharing agreements for R&D, fieldwork, FEED studies, and commercialization.

Beyond technical data produced as part of an R&D funding agreement is emissions data collected and managed by the EPA that would be useful to project developers to support efforts to identify candidate sites for carbon capture technology. Data collected as part of point source emitter reporting requirements is contained in the databases FLIGHT, eGRID and NEI (discussed in greater detail below), however, cross-referencing these repositories is challenging for outside developers looking to develop a composite understanding of a potential site.

Finally, NETL's data exchange – EDX – has a large amount of GS data resources that have been collected for research and development purposes. These data can be bolstered through aggregating similar and complementary resources collected by colleges, universities, and state geologic surveys. Further while the volume, quality and structure of the data is important, translating this input into useable tools and formats that could support commercial decision making could accelerate GS facility deployment while reducing development costs. To be clear, as a screening and planning tool, however, the enhanced EDX would not necessarily obviate the need for developers to produce the necessary site characterization for UIC VI permit applications.

Link to investability

An overarching goal of any federally funded CC deployment or GS siting and exploration project – aside from helping grantees bring their solutions to market – should be to generate new knowledge and disseminate it widely. Doing so would help follow-on projects to avoid the mistakes and capitalize on the successes of prior endeavors. It would also help reduce both actual and perceived risks borne by outside investors (e.g., technology risk), thus expanding the investor base and reducing the cost of capital charged to projects.

As noted, however, in the case of federally supported projects, there is tension between first movers who make risky private investment in federally assisted R&D/commercialization projects versus would-be follow-on developers who could benefit from being privy to some of the data created by first-movers. To the extent more information about first mover projects is made public in a timely manner and that information is useable for commercial purposes, together it would lower development costs and decrease site selection, construction, and future O&M risks. Lower risk would translate into lower all-in cost of capture, which would then increase the rate at which new follow-on projects are deployed.

The point about usability is salient to the issue regarding point source GHG, CAP, and HAP air emissions data that are collected by emitting facility operators and reported to the EPA and/or local air quality authorities. While there is not a statutory barrier that limits access to the data, there is a lack of harmonization that reduces its value from a commercial usability perspective. Improvements in its usability could help inform CCS project developers and help lower CCS project development costs.

Federally funded carbon capture R&D/ commercialization projects produce useful performance data, some of which should be shared publicly while still honoring grantee trade secrets and IP

Originally promulgated within the Stevenson-Wydler Technology Innovation Act (1980) and expanded within the Federal Technology Transfer Act (1986), the federal government granted statutory protection of data created within a cooperative research and development agreement (CRADA).[117,118] A CRADA is a collaborative research partnership between a federal laboratory or office and a non-federal entity, where parties provide personnel, facilities, equipment, or other resources with or without reimbursement (but not funds to non-federal parties). Proprietary information provided to the federal office or lab, and information generated under the project -- CRADA information-- may be protected from disclosure for up to five years. Each party may take title to intellectual property (IP) created by or invented by its employees. The Energy Policy Act (1992) extended the statute including the data protection provisions to energy R&D projects that receive federal financial assistance; this was upheld in the Energy Policy Act (2005). Depending on the provenance of the production of technical data, there are limitations to public disclosure.

The definition of "technical data" includes research and test data, technical designs, drawings, specifications and other scientific and technical information.[119] Technical data developed in the performance of work under an agreement with DOE belongs to the grantee, with the federal government having license rights (royalty free, world-wide, nonexclusive, irrevocable) for such data that can range from very limited rights to broad unlimited rights in terms of both use and further disclosure of the applicable data.[120] Technical data may be developed under the agreement with Government funding, private funds or with mixed funding. In general, the scope of the license is dependent on the source of funding for the development of the technical data but with some flexibility to enable the grantee to successfully commercialize the results. **Table 7** on the following page outlines the types of rights that can be negotiated between the grantee and the federal government.

Typically, confidential information – technical data that was produced exclusively with private funds and constitutes trade secrets, business information and/or financial information – may be accessible to the government under a limited rights agreement. Technical data produced with mixed funding often are typically placed within a government purpose rights license.[121] Special purpose rights are most like those related to findings resulting from a CRADA. Certain technical data created within the funding agreement – specifically listed and identified – can be protected from public disclosure for up to five years.

A grantee that produces an invention that is conceived or reduced to practice under a grant or cooperative agreement, known as a subject invention, can elect to retain title to the invention, where the federal government is granted a non-exclusive, non-transferrable, irrevocable license to practice the subject invention for or on behalf of the government.[122] The government encourages grantees who retain title to a subject invention to patent it; this both protects the IP of the grantee while also making public the details of the invention.

Table 7

Rights in Technical Data Provisions[123]

	Contractor Owns Technical Data	Restrictions on Disclosure Outside Government	Non-use, Non-disclosure Agreement Required with Recipient Outside Government	Contractor Consent Required for Disclosure Outside Government	Expiration of Protection
Unlimited Rights May disclose, reproduce, prepare derivative works, distribute copies to the public, and perform publicly and display publicly, in any manner and for any purpose including commercial purposes, and to have or permit others to do so.	Y	N	N	N	N
Government Purpose Rights May modify, reproduce, release, perform, display, or disclose technical data within the Government without restriction and outside the Government for Government purposes only.	Y	Y	Y	N	Y
Limited Rights May modify, reproduce, release, perform, display, or disclose technical data within the Government. May not be used for manufacturing or disclosed outside the Government, except in limited circumstances.	Y	Y	Y	Y	N
Special Protected Rights Negotiated but generally may not modify, reproduce, release, perform, display, or disclose technical data outside the Government.	Y	Y	Not Permitted	Not Permitted	Y

From the grantee's perspective, it is in its best interest to map out in detail which R&D deliverables will be funded by the various sources of funding (private, public, or mixed). The deliverables that need to be protected to maximize the chances of commercialization will be identified with granularity as, based on a range of public policies, the government should have broad rights to deliverables developed with public funds. DOE, consistent with law and practice, tends to afford the grantee a breadth of protections to support its commercialization efforts. In a recent DOE Funding Opportunity Announcement (FOA).[124] For example, where the entire program was placed within special protected rights related to technical data, DOE noted that:

> *"This program is covered by a special protected data statute. The provisions of the statute provide for the protection from public disclosure, for a period of up to five (5) years from the date of the development of data that would be trade secret, or commercial or financial information that is privileged or confidential, if the information had been obtained from a non-Federal party. Generally, the provision entitled, Rights in Data—Programs Covered Under Special Protected Data Statutes (Item 4 under 2 CFR 910 Appendix A to Subpart D), would apply to an award made under this announcement."*

While one of the primary missions of today's DOE is to support commercialization of technologies through financial assistance, there is a tension between accommodating the preferences of the grantee and publicly disclosing certain data to inform and accelerate sector-level learning and technology diffusion. Of course, one form of disclosure is the commercialization of a technology (and thus making it publicly available) by the grantee via the application of knowledge gained in part through the performance of a federally funded grant.

While this kind of commercialization is encouraged (and supported by the DOE) there may be knowledge and information that could be simultaneously shared to help all developers. That is, some data may not necessarily be designated as technical data that should be held from public access for five years. For example, the number of supplementary pumps planned as part of the amine system in a CCS installation represents know-how. It could be argued, however, that this is non-specific and could be released as part of documentation to the public well before five years.

The U.S. government, acting through DOE and/or the IRS, has given grant support (pursuant to cost-sharing agreements) and/or competitively selected ITCs (under §48A and §48B) for projects including the Petra Nova coal generation carbon capture project, an effort that has been successful, but its operations are currently suspended; the successful Port Arthur hydrogen carbon capture project; and the Kemper IGCC-CCS project that has been abandoned. In total, DOE has supported eleven CCS demonstration projects since 2009 with $1.1 billion in federal funding; it has also implemented a range of research and development programs for carbon capture technologies.[125,iii] Each project under a federal cost-sharing agreement is obliged to produce a final project report. These documents are voluminous and contain a wealth of data, but they do not contain critical performance and cost information that a follow-on project developer would need to make an informed decision.

[iii] DOE funded $484 million for six coal CCS projects under the Clean Coal Power Initiative, $200 million for two coal CCS projects under the FutureGen 2.0 Initiative, and $438 million for three industrial CCS projects under the Industrial Carbon Capture and Sequestration initiative.

As summarized in a paper by William Elliot (Bechtel) and Dr. Jon Gibbins (University of Sheffield) developed in connection with the National Petroleum Council's report on CCS to the Secretary of Energy:

> *To date, globally, several large post-combustion capture (PCC) projects to remove CO_2 from power plant flue gases, and a number of smaller ones, have been built using generally similar approaches. But, because the design, construction and operational details have largely been treated as proprietary, so far only very limited meaningful knowledge exchange has been able to take place, both from and to the projects and their developers and operators. In addition, design studies for other PCC plants that did not eventually get built have also either not been published or are heavily redacted in important areas. An open-technology, open-access capture initiative is therefore needed to accelerate CCUS deployment and reduce the costs of CCUS by enabling improved knowledge exchange and competition within the small fleet of subsidized plants that can be built over the next 5-10 years in the USA.*[126]

The NETL Baseline Studies for Fossil Energy Plants, for example, give construction cost, operating costs, and detailed performance specifications for various types of coal power, gas power, and hydrogen projects, but the information is theoretical and does not refer to actual projects.[127] The final project reports for taxpayer funded projects typically avoid inclusion of the construction cost, operating costs, and detailed performance specifications that a follow-on developer would need. Such information either is not submitted to DOE or, if submitted, is held as Confidential Business Information for a period of years. **Table 8** provides an illustrative contrast in information available for post-combustion capture on pulverized coal plants provided by the theoretical NETL Baseline Studies vs. a grant-funded project (Petra Nova) report.

An examination of several final reports from other grant-funded projects reveals that the Petra Nova project final report is indicative of general information quality available from carbon capture projects that benefitted from federal grants.[128,129,130] In short, critical information needed for owners/developers of follow-on projects is missing. As noted, based on interviews with project developers, the lack of information is a direct impediment to project development.

Table 8

Comparison of the quality of information, NETL Baseline vs. Petra Nova Project

NETL Baseline (Information is modeled/theoretical, but it is publicly available performance/cost data)	**Grant-funded project: Petra Nova** (Information available is actual, but the publicly released subset of information omits key data)
The 2019 DOE Fossil Baseline report (Case B11B Pulverized Coal with CCS) provides total cost breakdowns of principal subassemblies/ cost items for a new coal plant with carbon capture.[jjj,131] It also gives a "stream table," which is a step-by-step sequence of mass, temperature, pressure, and molecular composition of mixed gas flows, most critically flows into carbon capture and out to various exhaust stacks or compressors. This is a valuable resource for would-be developers or acquirers of carbon capture equipment, though there are *shortcomings* such as aggregating the entire carbon capture system together into a single cost figure and basing the 2019 analysis on a theoretical system of vendor CanSolv, notwithstanding the fact that the actual Petra Nova project using a Mitsubishi Heavy Industries solvent carbon capture system, went online in Texas two years before, in January 2017.[132]	The Petra Nova project's final report does not even give an exact total cost figure for the capture system and associated infrastructure, stating, *"Of the approximate $1 billion original investment, approximately 60% was spent on the capital investment of the Petra Nova carbon capture and cogeneration facilities and related costs. The balance of the investment covered up-front operating and administrative costs and the Petra Nova share of the CO_2 pipeline and West Ranch improvements. The source of funds includes the DOE Grant ($195 million), financing ($250 million), and sponsor equity."*[133] The report then goes on to say, with no apparent sense of irony, *"Experiences at Petra Nova will allow others interested in post-combustion CO_2 capture to better understand how capital and operating costs can be reduced for future facilities."*[134] Petra Nova had several serious early-year operating issues that caused repeated, unexpected shutdowns; however, insufficient information is provided regarding the root causes of these failures.

To promote accelerated adoption of CCS technologies, there needs to be a balance between what data may fall under the various technical data provisions that benefits the industry and the interests of the grantee that has committed resources to develop the information and know-how. Technical data, for example, such as construction costs, contract structures, high-level process flow, heat and mass balances, acceptance test

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[jjj] Key tables that contain much more detailed information than final project reports are Ex. 4-32 (block flow diagram with stream point #s, Ex. 4-33 stream tables, Ex. 4-40 Energy and Mass Balance, Section 4.2.9 Major Equipment List, Ex. 4-43 Total Plant Cost Details, & Ex. 4-4-45 Initial and Annual Operating and Maintenance Costs.

performance, and high-level operating performance could be disclosed at a level that protects trade secrets and proprietary information, but also at a level of granularity that could be useful to a would-be developer.

Harmonization of three federal air emissions databases

A developer, state or federal official, or member of the public who wishes to have a comprehensive understanding of actual (not modelled) performance characteristics of the subcomponents of an industrial emitter that may be an amenable site for carbon capture (or some other mitigation technique) faces a challenging task. The information needed to inform the work is spread across a variety of federal databases, the designs of which do not inform project development to the degree possible, even with no restrictions public sharing of data and information. While industry spends significant effort, time, and resources compiling and submitting the data, and the federal government spends similar efforts maintaining the systems, the resulting informational resources are not designed for commercial development purposes. While providing information to developers of pollution control projects was not the original intent of these databases, their repurposing could help reduce knowledge gaps regarding commercial project development.

There are three main federal databases, all managed by the EPA, that provide information about emissions relevant to analyzing industrial CO_2 emissions and associated CAP emissions: the Facility Level Information on Greenhouse gases Tool (FLIGHT); the Emissions & Generation Resource Integrated Database (eGRID); and the National Emissions Inventory (NEI) (**Table 9**). These databases were developed at different times, for different purposes, addressing different EPA and DOE statutory responsibilities. So is it not surprising that these three resources – when comparing data across them – may have conflicting information on the same entry (site/emitter), are difficult to crosscheck because of lack of harmonized identification data on facilities and individual stacks, and sometimes contain clerical and categorization errors, originating from reporting emitters themselves.

With respect to emitter information, it is essential for federal emissions databases of all relevant pollutants associated with CO_2 emitting sources to be error-free, comprehensive, consistent, and relatable. The current regime is, however, challenging. For example, the federal databases for CO_2 emissions (i.e., GHGRP FLIGHT), conventional and hazardous non-GHG pollutants (i.e., NEI), and for power plant/combined heat and power plants (i.e., eGRID) use inconsistent site names, owner names, addresses, GPS coordinates, units of measurement, equipment/stack identifiers, and levels of aggregation. Building the necessary the necessary knowledge and information, especially for permitting requirements, requires developer time and costs that ought to be mitigated.

Table 9

Federal databases on GHG and other emissions

Database	Information included	Value to CCS developers
FLIGHT	Facility-level GHG emissions from large facilities under the GHG Reporting Program of EPA	Identification of potential industrial candidates for CCS
eGRID	Plant-specific emissions data for electricity generating plants (NO_x, CO_2, SO_2, and mercury only)	Identification of potential electric sector candidates for CCS, including inside-the-fence industrial generators
NEI	Estimated air emissions for point, nonpoint, on-road, non-road mobile, and "event" sources (e.g., wildfires) Reported emissions at individual stacks include all CAPs and HAPs but not CO_2.	Economy-wide visibility into major sources of non-GHG conventional and hazardous air emissions that might be candidates for CCS

FLIGHT reports only GHG emissions, in metric tons, on an annual basis. It uses one set of identifying numbers for emitter facilities but uses a different set of identifiers within the actual emitter reports for individual process units. FLIGHT also allows aggregation of multiple combustion units. This combustion unit aggregation makes it challenging to cross reference CO_2 vs. CAP emissions for process heating units.

The following emissions information is reported by eGRID reports for some, but not all years[135]: short-tons of CO_2; some CAPs (missing particulates and VOCs); and one HAP (mercury) on a stack-by-stack basis for all power plants, including "inside-the-fence" industrial CHPs. It does not, however, report on industrial boilers that have no electric power production. eGRID names and identifying numbers are different from those in FLIGHT. In fact, the three main sub-reports (Unit, Generator, and Plant) in eGRID do not use internally consistent names for generating units within eGRID itself.[kkk] Moreover, eGRID has large variations from NEI in certain industries. For instance, eGRID reports approximately 15,000 tons of annual SO_2 emissions just from the CHP units inside

[kkk] For the sixteen calendar years 2004-2019, inclusive, eGRID has reports for only ten years. Hence, the U.S. Department of Energy actually subscribes to a private data base (Energy Velocity) that has made a business of harmonizing the eGRID federal data (at least for grid-serving units) into useful information.

Louisiana pulp mills, whereas the NEI reports total SO_2 emissions (from *all sources* in Louisiana pulp mills) at ~3,500 tons annually.[lll]

The NEI is completed every third year, with the data usually being published two years in arrears. The NEI reports (in short tons) all CAPs and HAPs on a stack-by-stack basis. However, identifying numbers and names of facilities, as well as numbers and names of individual stacks rarely coincide with those within FLIGHT or eGRID. If CO_2 data is reported, it is typically only on a facility-wide basis; SO_2 emissions can be obtained from a particular stack in NEI, but not the CO_2 from the same stack. The non-comparability is further exacerbated since FLIGHT reports the process unit where emissions were generated, whereas NEI reports the point where the emissions reached the atmosphere.

Using two examples, **Tables 10a** and **10b** highlight the challenges with comparing data across these databases. These examples are black liquor boilers (i.e., recovery boilers) at two Louisiana pulp mills (Graphic Packaging and Packaging Corporation of America). These are useful examples because these facilities are major emitters of GHGs, CAPs, and captive electricity generation. Instructive observations for both examples include: the ~10% discrepancies on CO_2 emissions between FLIGHT and eGRID (with eGRID units converted to metric), the SO_2 differences between eGRID and NEI, which cannot be attributed new emissions controls since the later-dated figures (eGRID, 2019) exceed the earlier figures (NEI, 2017) and the differences in reporting facility name.

[lll] The NEI number is from 2017, and the eGRID number is from 2018. We couldn't cross-check data for the same year since the eGRID 2017 data is missing. See prior footnote.

Table 10a

Comparison of databases using the Graphic Packaging Plant 31 example[mmm]

	FLIGHT (2019)	eGRID Unit Report (2019)	NEI (2017)
Name of Reporting Facility	GRAPHIC PACKAGING INTERNATIONAL LLC, West Monroe Mill Plant 31	Plant 31 Paper Mill	Graphic Packaging International LLC - West Monroe Mill #31
Identifying Number for Mill	1000602	50028	5734011
Name of Boiler	No. 4 Recovery Boiler	4BW (i.e., # 4 made by Babcock & Wilcox)	No. 4 Recovery Boiler Stack A and No. 4 Recover Boiler Stack B
Identifying Number for Black Liquor Boiler	LO3004/LO3005	10943	EIS Unit ID 81509713, but two Agency IDs (S3004 and S3005)
CO_2 (metric tons)	465,362	505,085	N.A.
SO_2 (metric tons)	N.A.	1,367	370 (combined)

Table 10b

Comparison of databases using the Packaging Corp. of America-DeRidder example

	FLIGHT (2019)	eGRID Unit Report (2019)	NEI (2017)
Name of Reporting Facility	Packaging Corporation of America	DeRidder Mill	Packaging Corp of America - DeRidder Paper Mill
Identifying Number for Mill	1006256	10488	722571
Name of Boiler	Recovery Boiler	REC	Recovery Boiler
Identifying Number for Black Liquor Boiler	69-01	Sequence # 10774	79810413
CO_2 (metric tons)	920,983	966,017	N.A.
SO_2 (metric tons)	N.A.	2,608	6.8

[mmm] This table provides a useful example of the issue of multiple stacks that report combined in eGRID but are separated in the NEI (stack A and stack B). Though not shown here, Plant 31 was also the source of a large 2018 discrepancy when it reported 6.4 million metric tons per year from "4BW" (a Babcock and Wilcox Recovery Boiler) in eGRID (egrid2018_data_v2 March 9-2020), vs. 0.468 million metric tons per year on FLIGHT from "No. 4 Recovery Boiler" (i.e., the same unit). The error was ultimately corrected when one of the authors pointed it out to EPA.

Expanding aggregation of GS data and making it useful for commercialization purposes

For GS facility project developers, owners, and investors, information related to injection projects and project-scale geologic characterization is important for helping to lower the barrier to development. As with carbon capture projects, the federal government through DOE-funded commercial and research contracts has supported a variety of well-drilling and characterization efforts to assess specific sites for GS suitability. Original and continuing efforts have primarily focused on data acquisition, data curation and model building for public and industrial R&D purposes. Expanded efforts are required to build the toolsets needed by multiple stakeholders such as developers, local communities, and policymakers to make informed decisions regarding GS commercialization.

Both DOE and the USGS have spent considerable effort characterizing and analyzing storage/sequestration resources. DOE has supported the determination of the capacity of various geologic formations to sequester CO_2 across the U.S. through its Regional Carbon Sequestration Partnerships (RCSP) initiative. This initiative has created information on reservoir and seal properties of regionally significant formations, testing protocols, and initial validation of modeling and monitoring technologies.[136] The RCSP successor program is the Carbon Storage Assurance Facility Enterprise (CarbonSAFE) initiative that began in 2016, which is ongoing and performing identification and detailed characterization of geologic storage sites. The vision of CarbonSAFE is to understand the development of a CCS storage site from the feasibility study to the point of injection.[137] Separately, in 2013, the USGS published its own assessment of possible saline storage resources.[138] DOE also has funded a wide variety of externally sponsored partnerships, including the NATCARB/Atlas, an NETL-managed database of storage resources – the FE/NETL Saline Storage Cost Model-- that feeds into US EIA's national energy model (NEMS).

The Energy Data Exchange (EDX) – a platform developed by NETL – is the cloud-based central repository and research collaboration environment that organizes the majority of DOE created and/or sponsored GS data and the development site for tools, models, and visualization functionality to make sense of said data. EDX aggregates databases, enables analytical tools development, and provides virtual workspaces for researchers to contribute to – and the public to use and view –resources relevant to GS.[nnn,139,140,141] The

[nnn] See Stephen Carpenter's whitepaper for list of regional partnerships.

data collected as part of RCSP and CarbonSAFE, in addition to other sources, have been collected and organized within the EDX. Examples include GeoWELL[ooo], NATCARB[ppp] and CO_2-SCREEN.[qqq]

Much of the current functionality surrounding EDX data, tools and capabilities have been developed by and for an R&D audience. DOE has recognized that increasing the useability of existing functionality, while building new tools and products for a wider set of stakeholders such as commercial developers, community members and policymakers is crucial to helping accelerate the scale-up of GS facilities as part of the CCS value chain. The BIL has allocated some funding to EDX-related initiatives to enhance its capabilities. Examples of activities meant to increase the value of EDX to a wider set of stakeholders include:[142]

- Aggregating DOE-funded data with other public, authoritative datasets to increase the useability and completeness of resulting integrated databases
- Environmental justice and social justice databases to support CCS project efficiency and improve GS stakeholders' understanding of EJ & SJ factors and how they may affect commercial, regulatory, and research applications.
- A National Well Database providing up-to-date, integrated resource supporting CCS development across the country by providing critical insights for safe injection site selection, while leveraging existing well infrastructure, limiting costs and the fossil energy footprint.

An improved EDX that draws from the largest possible data sets, aggregated from multiple authoritative repositories, coupled with analytical and visualization tools that minimize the need for laboratory-scale computing facilities or other resources, would lower the barrier to GS commercialization. It is likely that professionally trained geologists and other specialists will need to remain as part of the knowledge ecosystem to perhaps help interpret information provided to various stakeholders. However, knowledge sharing, and informed decision-making could be made more time efficient and with less cost, provided upgrades to EDX are made with this expanded stakeholder sets of needs in mind.

[ooo] A map-based application that provides quick access to websites of primary sources of subsurface geologic and wellbore (oil, gas, and underground injection) information for appropriate U.S. state, tribal and federal agencies.

[ppp] GIS-based tool for viewing CCUS potential across the United States.

[qqq] Applies U.S. DOE methods and equations for estimating prospective CO_2 storage resources for saline formations. This provides a dependable method for calculating prospective CO_2 storage resources which allows for consistent comparison of results between different research efforts.

Policy recommendations

A few targeted policies would help overcome the barriers to carbon capture and geologic storage project information synthesis and public sharing. These policies would help the relevant agencies build on and expand the already substantial data development and characterization efforts.

First, EPA emissions databases should be harmonized (Recommendation 3A). Next, DOE should require that all key engineering performance data be disclosed by the funding recipient to the Department as a condition of awarding competitively procured cost-sharing agreements for carbon capture projects. (Recommendation 3B). The DOE should also form a working group of past CCS grantees, potential developers, IP attorneys and the relevant national laboratories to examine and make recommendations on the collection and sharing of technical data created and used within federally funded projects (Recommendation 3C).

In addition, NETL's existing EDX data platform should receive additional BIL funding and continue to be significantly expanded to increase its commercial and market development relevance. This should be done in coordination with DOI, academic institutions and state geologic surveys (Recommendation 3D). It should also be done in coordination with the intended stakeholders who will make use of EDX's expanded capabilities (Recommendation 3E).

Recommendation 3A. OIRA should initiate efforts to harmonize federal emissions databases

The Office of Information and Regulatory Affairs (part of the Office of Management and Budget) should take the initiative to harmonize federal air pollution databases to facilitate identification and screening of facilities amenable to CCS retrofits. Harmonization of the Greenhouse Gas Reporting Program (EPA), National Emissions Inventory (EPA) and Emissions & Generation Resource Integrated Database (DOE) would materially reduce the efforts of would-be carbon capture developers to screen for ideal host facilities.

Recommendation 3B. DOE should require all key engineering performance data be disclosed by the funding recipient to DOE, as a condition of awarding competitively procured cost-sharing agreements

Government rights concerning technical is clearly outlined in statue and in large part is a function of the source of funds that created the information in the first place. The Department of Energy should require that all key engineering performance data be disclosed by the funding recipient to the Department as a condition of awarding competitively procured cost-sharing agreements for carbon capture projects. Without infringing upon private corporate intellectual property or patents, DOE should subsequently negotiate timely and comprehensive public disclosure of such information with the funding recipient.

Recommendation 3C. DOE should form a joint industry and national laboratory committee to examine the collection and dissemination of technical data as part of federally funded projects

As noted, access to key data is critical for the CCS industry to move forward. DOE should use BIL funding (§40305) to convene a working group to examine and articulate what technical data would be useful to would-be developers. The committee would make recommendation as to how these data needs could be addressed in view of a grantees' commercialization requirements. Outcomes from committee recommendations would be the basis for negotiations for public disclosure of key engineering performance data (See Recommendation 3A).

Recommendation 3D. DOE should collaborate with DOI and other authoritative sources of GS data to expand NETL's EDX database and identify commercially relevant data gaps

In December 2021, DOI's U.S. Geological Survey (USGS) and DOE's Office of Fossil Energy and Carbon Management announced a plan for cooperation on assessing global, regional, and national resources for geologic carbon storage.[143] Building an expanded geologic storage repository of curated data should be included as part of this collaborative effort. DOE and DOI have significant amounts of data from previous and ongoing programs on carbon sequestration; these include the national assessment of geologic carbon dioxide storage potential and the RCSP Initiative. This data could and should be coupled with data gathered and/or residing in various universities and state geologic surveys. At the same time, this collaboration should identify commercially relevant data gaps, that if closed, could reduce industry-wide costs to GS facility development.

Recommendation 3E. DOE should collaborate with an expanded set of EDX information users such as commercial developers, local communities, and policymakers to identify, prioritize and fund functionality beyond current EDX development plans.

Beyond data aggregation, the BIL has provided funding to DOE efforts to expand the capabilities of EDX in terms of analysis and visualization tools. Tool development should include deep and sustained engagement with an expanded set end users (e.g., commercial developers, community groups, policymakers, etc.) to ensure efforts are fit for purpose. Doing so would also offer an efficient approach to gathering feedback and prioritizing additional funding for feature enhancement based in part on CCS commercialization relevance.

THEME 4. STREAMLINE FEDERAL AND STATE REGULATORY REQUIREMENTS ACROSS THE CCS VALUE CHAIN OF CAPTURE, TRANSPORTATION, SEQUESTRATION, AND LONG-TERM MONITORING

Federal and state leadership in supporting transport and sequestration can improve the U.S. investment case for CCS

Overview

CCS value chain complexity – aligning capture, transportation, sequestration, ongoing site care, and long-term liability transfer elements – creates coordination costs and development risks that are disadvantageous to most developers, relative to other energy projects. Even highly experienced investors and specialty pools of funds that are otherwise quite willing to pursue "risky" projects shy away from CCS in large part because of value chain complexity. Beyond the technical and organizational challenges of CCS is the regulatory regime. Each of the four CCS links are currently regulated relatively independently from each other, with little coordination across federal, state, and local agencies.

Carbon management has become a core competency and strategic imperative of the DOE, as exemplified by the widely publicized mission reorientation from the Office of Fossil Energy to the Office of Fossil Energy and Carbon Management (FECM). One of the key pillars for advancing carbon management approaches to support deep decarbonization is reliable carbon storage and transportation, where FECM will *"establish the foundation for a successful carbon transport and storage industry… by making advancements in storage technologies and industry…"*[144] While supporting technologies for transportation and storage is very important, so is the unique role the federal and state governments could play, given the complexity of projects and their greenfield status.

Much like rural electrification, the interstate highway system, and more recently, rural broadband access, the public sector has provided direction, guidance, and substantial resources to seed new industries, providing a foundation on which commercial developers build.[145,146,147] The same is required now to grow the CCS industry at scale. Pipeline transportation, geologic storage and long-term site care are dimensions of large-scale carbon management where public involvement is needed by first movers. Specifically, working together, federal and state governments can: (i) mitigate uncertainties related to permitting and pore space ownership; (ii) adopt a performance-based approach to financial responsibility for EPA Class VI wells; (iii) ensure scale economies; and (iv) ensure that transportation and sequestration infrastructure is designed to mitigate market power of a few operators. Taken together, these actions would significantly increase the investment case for CCS in the U.S.

Link to investability

There are historical, financial, legal, structural, and regulatory reasons as to why the oil and gas industry is organized into distinct upstream, midstream, and downstream sectors. This structure has corresponding specialists in the investment community -- financial investors, lenders, credit, and equity analysts, and managers specialize in these individual links in the value chain because, in part, garnering competence in any of the three is a significant challenge.

In contrast, carbon capture developers are required to master upstream (capture), midstream (pipelines), downstream (geologic sequestration) and long-term monitoring links in the value chain. Individual "projects" must span all sectors, because of lack of adequate existing pipeline and storage infrastructure to support carbon capture scale up. At-scale deployment of pipelines and storage with federal support for FOAK facilities – coupled with state-level regulatory clarity - could lower development risks, operational risks, and business complexity. With such infrastructure development, a major GHG emitter could concentrate solely on implementing the carbon capture operation and uncertainties about transport and GS siting would not hold-up development.

Separate from the issue of who pays for transport and GS infrastructure is the issue of ownership and price regulation. If the scaled-up infrastructure is publicly owned, like federal transmission lines or state/local social infrastructure, price regulation would not be needed. However, if the government-supported infrastructure is privately owned, price regulation may be necessary to avoid the specter of monopoly pricing.

Uncertainties regarding permitting: interstate pipelines

Siting and permitting CO_2 pipelines does not pose substantially different technical challenges from those of gas pipelines or electric transmission, however from a permitting perspective, CO2 pipelines posed far greater challenges. Demand for natural gas and electricity over the past century has yielded well-defined regulatory frameworks for evaluating and approving associated infrastructure projects. Agencies (both state and federal) have been granted clearly articulated jurisdiction over siting gas pipelines and electric transmission and have, in turn, developed processes that, while not always streamlined, are well-defined. As demand for CO_2 transport infrastructure increases through the growth of both CCS and direct air capture, similarly robust siting frameworks, now absent, will be needed.

Importantly, both FERC (pursuant to its interpretation of the Natural Gas Act), and the Surface Transportation Board (STB) (pursuant to its interpretation of the Interstate Commerce Act), have indicated that neither agency has jurisdiction over siting of inter- or intrastate CO_2 pipelines.[148,149] This will be a significant problem if more interstate CO_2 pipelines are built, and more market participants make use of the CO_2 pipelines (as is potentially the case within the CO_2 hub model within provisions in the BIL). **Table 11** outlines the range of obstacles developers face when confronted with issues surrounding interstate pipelines.

While there are many issues surrounding interstate pipeline needs for scaling CCS, some progress has been made. For example, the USE IT Act[150] clarified CO_2 pipeline eligibility for streamlined review of any necessary federal permits (e.g., for federal lands) that might be required and directed the Council on Environmental Quality (CEQ) to establish guidance for expediting CO_2 pipeline development.[151] Also, the components of the CCS value chain are deemed covered projects under Title 41 of the Fixing America's Surface Transportation (FAST-41). Only one intrastate project – the Denbury Riley Ridge to

Natrona Project CO_2, a 243-mile, three-segment pipeline within Wyoming, has been approved under this process, and it took just over six years to get permitted.[152]

Table 11

Challenges of Siting Interstate CO_2 Pipelines[153]

Requirements	Authority	Challenges
Siting rules and processes	States	1. In many states, the regulations for CO_2 pipelines are not clear because they fall within the statutes for other types of pipelines. 2. Builders of interstate pipelines face widely varying regulations of multiple states that the pipelines pass.
Rights-of-way/eminent domain	BLM (federal lands) States (non-federal lands)	1. The availability of eminent domain for CO_2 pipelines varies among states. 2. Unclear whether the eminent domain authority of natural gas pipelines would extend to CO_2 pipelines in many states.
Common carrier status requirements	BLM (federal lands) States (non-federal lands)	1. Common carrier requirements vary among states.[rrr] 2. Unclear whether the entire pipeline is required to act as a common carrier when the pipeline passes both the state with common carrier requirement and the state without the requirement.

Uncertainties regarding permitting: UIC VI wells

Obtaining permits for geologic sequestration is a second major siting challenge. Obtaining UIC VI permits to inject CO_2 in geologic reservoirs poses significant risk to project developers due to a lengthy and uncertain timeline. As of January 12, 2023, only two operations had Class VI permits issued by EPA; the permits for 30 operations are pending.[154] In the public rulemaking process leading up to the current Class VI regime, both industry and environmental groups encouraged EPA to keep the rule non-prescriptive and require site- and project-specific matching of approach to local conditions. This flexibility has, however, also generated uncertainty, and created a prolonged negotiation between each GS project developer and EPA to develop a consensus on the sufficiency of the permit approach. To fully assess UIC VI applications in a timely manner, EPA likely needs additional staff, should engage technical experts to inform the permitting process, and should delegate permitting authority to states (see also

[rrr] Some states (e.g., Montana) grant eminent domain authority only to the CO_2 pipelines operating as common carriers. Private pipelines are permitted but are not allowed to use the power of eminent domain. On the other hand, North Dakota requires all CO_2 pipelines to operate as common carriers. Many other states do not have common carrier requirements for CO_2 pipelines.

Carpenter paper).[155,156] These processes and needs could be supported by the BIL, which provides $5 million to EPA for Class VI permitting each year from 2022 to 2026 and $50 million for states to establish their own Class VI permitting programs.[157]

Another fundamental issue with UIC VI permitting is the site characterization. As an initial filter, developers use existing geological information resources (**Theme 3**) to select promising geologic sequestration sites for characterization, after which they create commercial-level geophysical data to accurately select the site (i.e., area of review) for the Class VI application. Such project-level characterization activities by an individual developer are inherently financially risky, like oil and gas exploration, where substantial and expensive exploratory and geophysical efforts are required. Such efforts include, among other things, accurately mapping and modeling the subsurface with sufficient accuracy, developing detailed specifications such as injectivity and porosity, and modeling plume formation and migration.

If it is determined that a selected site is not amenable to GS, the developer will have already spent millions, or tens of millions of dollars. The developer will then have to assess if it has the resources to repeat the process at another site or abandon the project altogether due to lack of funding or an acceptable path to financial returns. Provided that most subsurface formations have not yet been characterized to commercial specificity, GS projects may take on some characteristics of “wildcatting” prevalent in the early days of the oil industry. In contrast to the fossil fuels industry, however, the payoff for finding an acceptable GS site is modest (unless the GS site owner can establish a local monopoly and charge exorbitant prices). The profitability of a GS site for anthropogenic CO_2 is effectively capped because the sum of total prices charged by the owners of the three portions of the value chain, i.e., carbon capture, pipeline, and GS, cannot exceed the $85/metric ton value of the 45Q tax incentive.[sss]

If carbon management is to successfully achieve gigaton-scale results in the near or intermediate future, a more organized and resource efficient approach is essential. If, for example, federal funds are used to develop an initial set of commercially appropriate subsurface characterizations, this could reduce both the costs and risks associated with any one or team of developers. Essentially, such an effort would be an expansion of NETL’s CarbonSAFE Program, Phase III: Site Characterization and Permitting[158] beyond the five locations identified.

[sss] In special cases, if extra revenues were available for a CCS project from state cap-and-trade, state LCFS programs, or bankable voluntary credit programs there may be more revenue available.

In September 2022, NETL and FECM released the FOA that funds CarbonSAFE, focusing on detailed site characterization (Phase III), permitting (Phase III and III.5), and construction (Phase IV) stages of project development.[159] Federal support of that type would be analogous to past ambitious technology innovation programs, such as the Eastern Gas Shales Program, instrumental to the shale gas revolution.[160] This approach would also reduce the time needed to obtain UIC VI permits because the underlying data would already be "certified" as correct, sufficient to meet the permitting application requirements. In combination, these would increase the commercial interest of first movers in developing GS projects.

State regulation of pore space ownership and interactions with federal ownership

Pore space ownership certainty and aggregation of pore space (unitization) into a GS site large enough to be economically viable is critically important to successful CCS. Other than on federal lands, this is a matter of state law. Determination of pore space ownership is not, however, necessarily a straightforward process, and unitization presents challenges in certain states, increasing both the development uncertainties and costs of GS projects.

Policies on and regulation of pore space ownership is primarily the domain of the states (for non-federal or fee lands), and is typically, although not uniformly, described in state statutes as subsurface space that is devoid of minerals. Generally, most states via statute or case law follow what is known as the "American Rule" where the surface owner owns the geologic pore space.[161] In some cases, such as Kansas, Louisiana, Michigan, Texas, and New Mexico, for example, ownership is vested in surface owner by case law. In other states, such as Wyoming, North Dakota, Utah, Kentucky and Nebraska, ownership is vested in surface owners by statute.[162] Other states such as Colorado, Illinois and Pennsylvania have no guiding case law or statutes and ownership is ambiguous.[163] There is, however, policy nuance within and among states, especially where there is a split in ownership between the surface landowner and the mineral estate that lies beneath.[164]

Additional complexities face sequestration project developers when the federal government is the landowner. The so-called split estate question also remains unresolved where pore space is managed by the federal government, largely through the U.S. Department of the Interior Bureau of Land Management (BLM). Especially in Western states – where much of the viable GS pore space is located – it is not clear as to whether the U.S. retains ownership of non-mineral geologic pore space underlying the millions of acres of split-estate lands patented by the federal government under the Stock-Raising Homestead Act (SRHA).[165] A useful, recent Instruction Memorandum (IM 2022-041) issued by the Department of Interior concerning rights-of-way authorizations for GS on federal lands indirectly acknowledges that BLM does not own or control non-mineral pore space under SRHA.[166] As in the case for states, prospective GS developers will be faced with resolving ownership ambiguities as part of their screening process; resolution of these issues could also involve a protracted legal processes.

State regulation of unitization of pore space

The requirements of various states for coordinating multiple pore space owners (generally, as noted, the surface owners) are not well established. Unitization, the agreement to jointly operate a producing area commonly used in the oil and gas industry, could be applied to CO_2 storage. Although many states allow oil and gas reservoirs to be unitized for economic development, most of the states have not addressed pore space unitization for CO_2 sequestration.[167] Absent rules for mandatory unitization, a CO_2 storage operator must obtain voluntary agreements from 100% of pore space owners to avoid the risk of being sued for trespassing by holdouts (see Carpenter).

Issues related to unitization appear to be no more difficult than those encountered today in the oil and gas industry, subject to the presence of clear rules. Locations have never been unitized for oil and gas because of fragmented mineral rights ownership and lack of mandatory unitization laws (such as the East Texas field) still have large producing regions.[ttt,168] Texas rules clearly indicate that there cannot be mandatory unitization, requiring 100% agreement across pore space owners to proceed. On the other hand, Kentucky, Louisiana, Oklahoma, Montana, North Dakota, and Wyoming, have statutes in place permitting pore space unitization.

An alternative to unitization for assembling a fully contiguous pore space ownership lease would be to treat the sequestration of CO_2 as a matter of public necessity and thereby applying state eminent domain. Some states, such as Louisiana, have begun to expand

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[ttt] J.R. Boyce, in *Encyclopedia of Energy, Natural Resource, and Environmental Economics*, shows that by 1975 Texas, which has only voluntary unitization, had only 20% of production from unitized fields, whereas in Oklahoma, with a 2/3rds vote sufficing, 38% of production was unitized.

their eminent domain authorities to cover CO_2 storage operations; but many other states remain unconvinced or antagonistic towards the use of eminent domain for CO_2 storage.

The federal government has no specific federal statutory authorization for condemnation of private land for CO_2 pipelines or private subsurface rights for CO_2 storage. In both state and federal cases, the taking of private property is typically allowable if: the taking is deemed to be in the public interest; proper procedures are created/followed (i.e., Title V of the Federal Land Policy and Management Act of 1976); and fair compensation to the owner is provided. In cases related to pipelines transporting CO_2 to EOR operations, state eminent domain powers have been used to secure pipeline rights-of-way.[169]

Analogous federal unitization interventions may be warranted for GS projects if, among other considerations, unitization for a proposed GS project is indispensable to obtaining sufficient scale and proximity to assure GS project feasibility (i.e., hubs). Creating some federal eminent domain power for pipelines and subsurface rights would have the effect of incrementally reducing development cost and uncertainty, critical for FOAK projects.

Adopting a performance-based approach to financial assurance for permitting UIC Class VI injection wells for GS

There are two distinct issues highlighted in this and the next subsection. The first issue relates to “financial assurance” -- the fund size an operator of a Class VI injection well must set aside (or demonstrate that it can pay) to meet the operator’s legal liabilities for personal, property, and environmental damages resulting from migration of the CO_2 in the subsurface.

The second issue relates to the liability transfer provisions by which a U.S. state may choose to assume some or all an injector’s post-closure legal liabilities and/or responsibilities. It is not suggested there should be any removal of liability for poor site selection, inadequate maintenance and closure/abandonment, or accidental migration/releases from the shoulders of GS operators.

Comparison of financial assurance requirements for underground injection wells

The financial assurance issue is important for the investability of a GS project because the money set aside, or insurance policies that must be purchased, are a direct project cost, likely paid with equity funds. In one case the financial assurance cost estimate exceeded the actual project capital cost estimate.[uuu] It is worth emphasizing again that this discussion is not focused on whether an injector should be liable for damages, but rather the amount of financial assurance sufficient to satisfy regulators and how this amount is established for other underground injection programs.

Injection of fluids into the subsurface in the U.S. falls under the Safe Drinking Water Act (42 USC §300f), for which EPA has promulgated regulations under the Underground Injection Control (UIC) program (40 CFR 144). EPA says, "The goal of federal [UIC] regulations is to prevent contamination of 'underground sources of drinking water' (USDW) from the placement of fluids underground through injection wells. The underground injection control regulations do this by regulating the construction, operation, and closure of injection wells."[170]

There are different regulations pertaining to each of six classes of wells (UIC Class I to UIC Class VI). The regulations of most interest for examining precedents and procedures for Geologic Sequestration are Class I (industrial and municipal waste disposal wells, including Class I Hazardous waste disposal wells), Class II (oil and gas related injection wells, including injection of CO_2 for EOR), and the newest, Class VI (geologic sequestration of CO_2).[vvv]

The basic geologic processes and operational risks of GS and CO_2-EOR are, in many respects, quite similar (see Hovorka). The current regulatory approaches under Class II and Class VI, however, treat the two CO_2 injection situations quite differently. Specifically, the Class VI financial assurance requirements for CO_2 injected for GS are patterned after, and in some ways more burdensome than, the regime for Class I-Hazardous Waste wells. The apparent anomaly from the point of view of protecting public health, is that injection of inherently non-hazardous CO_2 (unless contaminated with H_2S, etc.) would intuitively seem far less concerning than injection of hazardous wastes. CO_2 for use in food,

[uuu] Personal communication with active project developer, September 2022.

[vvv] See EPA's front page for UIC at https://www.epa.gov/uic

beverages, and medicine is often obtained from capture of anthropogenic CO_2 from industrial sources: the same CO_2 stream could go into a Class VI well or into beer.[171] While not a significant volume, IEA estimates food and beverage use of captured anthropogenic CO2 at ~15 million metric tons/year.[172]

Substances that may be injected under Class I-Hazardous (which must either be "de-characterized" or shown not to migrate) include: ignitable wastes; corrosive wastes (pH <2 or >12.5); reactive wastes (form explosive mixtures with water;); and toxic organic wastes. [www,173] EPA has, however, promulgated regulations stating that CO_2 is *not a hazardous waste* under the relevant federal statute, the Resource Conservation and Recovery Act (RCRA).

> *"The U.S. Environmental Protection Agency (EPA or the Agency) is revising the regulations for hazardous waste management under the Resource Conservation and Recovery Act (RCRA) to conditionally[xxx] exclude carbon dioxide (CO_2) streams that are hazardous from the definition of hazardous waste, provided these hazardous CO_2 streams are captured from emission sources, are injected into Underground Injection Control (UIC) Class VI wells for purposes of geologic sequestration (GS), and meet certain other conditions.* ***EPA is taking this action because the Agency believes that the management of these CO_2 streams, when meeting certain conditions, does not present a substantial risk to human health or the environment, and therefore additional regulation pursuant to RCRA's hazardous waste regulations is unnecessary.*** *EPA expects that this amendment will substantially reduce the uncertainty associated with identifying these CO_2 streams under RCRA subtitle C and will also facilitate the deployment of GS by providing additional regulatory certainty."* [emphasis added][174]

Even though EPA has established that captured/injected CO_2 is not hazardous, the financial assurance provisions of EPA's rules for CO_2 are more onerous than the comparable rules for Class I-Hazardous wells. Financial assurance provisions are safeguards to ensure that owners of various types of environmentally sensitive facilities do not cause environmental damage and then go bankrupt, leaving the public responsible for clean-up. As such, developers and operators of sequestration projects must demonstrate a measure of financial capability or responsibility when applying for GS

[www] As to de-characterization, "Prior to disposal in a Class I nonhazardous well, hazardous wastewaters must be de-characterized (i.e., the hazardous characteristic must be removed) by any means including treatment, dilution, or other deactivation through aggregation of different wastewaters, including commingling with nonhazardous or exempt wastewaters."

[xxx] The two conditions are that (i) the pipeline carrying the CO_2 to the injection point meets U.S. Department of Transportation CO_2 pipeline standards and (ii) the CO_2 stream to be injected "has not been mixed with, or otherwise co-injected with, hazardous waste at the Underground Injection Control (UIC) Class VI permitted facility." The conditions are found at 40 CFR 261.4(h). https://www.govinfo.gov/app/details/CFR-2015-title40-vol26/CFR-2015-title40-vol26-sec261-4

injection permit to guarantee the construction, operation, closure, and safe post-closure monitoring of facilities.[175]

Financial assurance requirement regulations for Class VI GS operators (40 CFR §146.85(a)) state that GS owners or operators must use a qualifying instrument sufficient to cover the cost of four areas: future corrective action (i.e., preventative action for potential problem areas such as old well bores); injection well plugging; post-injection site care and site closure, and; emergency and remedial response.[176] If not using insurance or letters of credit, the applicant is required to fund in cash before permitting, but "may" be allowed to pay in over time. i.e., the base expectation is cash up front.

In contrast, a UIC I-Hazardous applicant is required to provide for future possible risks and costs of only one of the four areas and the cash can be paid in over the life of injection, easing cash flow burden on the operator. Future costs that must be provided for by prospective operators of UIC I-Hazardous sites are only to create a "Plugging and Abandonment Trust Fund" (40 CFR §144.63).

The differences are summarized in **Table 12** below. This is not a liability question, but rather a cash flow and funding question that affects investor decisions. In both the UIC VI and the UIC I Hazardous Waste case the operator is legally responsible for the four liability elements listed in **Table 12**. The distinction between the two regimes is what monies need to be set aside as part of financial responsibility requirement. In either case, qualifying instruments include trust funds, surety bonds, letters of credit, escrow account, insurance, and self-insurance.

While the form of the qualifying instrument is not an issue, uncertainty about the quantity and timing of funds needed to adequately demonstrate financial responsibility as per UIC VI permit requirements presents an obstacle to FOAK GS projects. The evidence so far, limited though it is, shows the band of uncertainty.

Table 12

Financial Responsibility Comparison: Class I Hazardous Waste Injection Wells vs. Class VI CO_2 GS Injection Wells[177,178,179]

	Class I-Hazardous		Class VI Geologic Storage	
Area of Required Action	**Injector Responsible**	**Financial Assurance Requirement and Timing**	**Injector Responsible**	**Financial Assurance and Timing**
Corrective Actions (e.g., fix old wells) during operating period.	Yes	Not required.	Yes	Yes required. Upfront assurance is required in all four areas as a condition of the initial permit allowing commencement of injection. In the financial responsibility demonstration, the owner or operator is required to deposit the required amount of money into the trust prior to permitting, or it may have the option to exercise a "pay -in period" specified by the UIC Program Director. EPA advises regional directors to use "the shortest pay-in period possible."[180]
Provide for Plug and Abandon	Yes	Yes required. Timing: normal case is a trust ratably filled over life of injection.	Yes	
Emergency Remediation Response	Yes	Not required.	Yes	
Post Closure Monitoring & Care	Yes	Yes required, but at the time the Operator seeks EPA approval of the Closure Plan—not at commencement of injection.[yyy]	Yes	

In terms of the amount of financial assurance required vs. CO_2 to be injected for UIC VI permits issued in the U.S., the financial responsibility has ranged from \$0.41 to \$39 per metric ton (see **Table 13**).[181,182,183,184,zzz] As noted, for UIC VI the cost of providing financial assurance is incurred at project outset (i.e., full pre-payment), while for UIC I Hazardous Waste projects the full value of the qualifying instrument can be paid into over a period of time. Financially, this timing difference means that the financial assurance is funded by expensive project construction equity (at the margin) for UIC VI, whereas the assurance can be paid from operating cash flow over time for UIC I.

[yyy] See https://www.ecfr.gov/current/title-40/chapter-I/subchapter-D/part-146/subpart-G/section-146.71 at (a)(3) which requires financial assurance meeting standards of §144,52(a)(7) as a required part of the Closure Plan.

[zzz] EPA requires the owner or operator to provide any updated information related to their financial responsibility instrument on an annual basis if there are any changes. In 2016, the total cost for the two ADM CCS projects was updated to \$92.5 million, up from \$82 million (\$39 million for #1, \$43 million for #2). It is not known what affected the increase, but it is presumed due to additional costs originating largely from inflation.

Table 13

Amount and nature of "financial assurance" required for permitted UIC VI operations[185, 186, 187,aaaa]

Project	Financial responsibility	Covered by	CO_2 injection rate (annual) (million metric tons)	Expected maximum total injection mass (million metric tons)	Levelized financial responsibility ($/metric ton)
ADM #1	$39 million	Self-insurance	0.3	1.0 (~3 yrs)	$39
ADM #2	$43 million	Self-insurance	1.0	6.0 (6 yrs)	$7
Project Tundra (Minnkota)	$33 million	Trust fund and Insurance	4.0	80 (20 yrs)	$0.41
Red Trail	$18 million	Surety bond	0.18	3.6 (20 yrs)	$5

While the EPA provides general guidance on how to perform UIC VI cost estimates, a general lack of operating experience has encouraged overly conservative parameters, especially when considering USDW remediation. With well-characterized sites in combination with dollar-denominated damage distributions for site-specific risk events, a probabilistic (e.g., Monte Carlo model based) assessment of financial consequences can be obtained, while allowing for analysis of key drivers of financial consequences.[188] For example, a stochastic model (e.g., CCSvt model) has been applied in support of several UIC VI projects involving a range of industry sectors.[189]

Preliminary findings from this analysis suggest that projects with a pure CO_2 stream, sited and constructed away from populations centers, that adhere to established UIC VI regulatory standards for operation and stewardship, would likely yield negligible endangerment to USDWs. The associated financial consequences relative to the capital cost of developing, constructing, and operating a CCS facility should also be small.

Potential post-closure assumption of liabilities by states from operators

States are also involved in CO_2-EOR and CO_2 GS permitting and liability. As seen in Table 13, two states -- North Dakota and Wyoming – have been delegated state primacy for Class VI well permitting. To give additional protection to state residents, several states have supplemented the EPA's practice of obtaining financial assurance from GS operators (as discussed in the prior subsection) by collecting injector fees over the life of

[aaaa] Note that Project Tundra (Minnkota) and Red Trail projects – both located in North Dakota – have been issued Class VI permits by the North Dakota Industrial Commission, the state body empowered to do so under North Dakota's primacy agreement with the EPA.

injection. Such injector fees are typically deposited in a CO_2 publicly administered storage facility trust to be used for costs related to the long-term monitoring and management of CCS projects (e.g., Indiana HB1209).[190]

Some states have also established procedures by which post-closure liability for long-term environmental or tort issues can be transferred from private operators to the state in which the injection took place. This is a complex and evolving area. **Table 14** outlines the jurisdictional oversight in which liability transfer occurs for selected states.[bbbb]

As different states take different legislative approaches to post-closure liability transfer (or the related issue of responsibility for physically performing on-the-ground monitoring and site care), some state-specific legislative approaches have been criticized for lack of rigor. A state that allows GS operators to irrevocably transfer all future liabilities to that state, without recourse back to the operator even in case of negligence or fraud, raises many concerns and could incentivize negligent behaviors on the part of the operator.

Instead, a state that assumes future liabilities from a GS operator should follow the same protective contractual arrangements that a private party would use. For example, in a typical commercial transaction, if Party A wishes to transfer an environmental liability to Party B, the transfer is contractually documented with Party A (transferor) making representations about the exact status of the property, presence of environmentally sensitive substances, and the exact nature and quality of remediation work or containment work that has been performed. If Party B (transferee) later learns, and can prove, that Party A's representations were fraudulent or that the claimed remediation/containment work was performed in a negligent manner, Party B typically has the right directly to invalidate the liability transfer under the terms of the contract. It seems that a similar contractual approach would be the responsible legislative model whether "Party B" is a state or a private party.

[bbbb] Louisiana, Montana, and Indiana have also adopted programs that accept the long-term care of GS post-closure, subject to conditions being met.

Table 14

Requirements on Storage Permitting & Post Closure Site Care/Liabilities in Selected States[191]

		Texas	North Dakota	New Mexico	Wyoming	California	Louisiana	Arizona	West Virginia
Storage Permitting	Agency Jurisdiction: Class II Wells	Railroad Commission [192]	North Dakota Industrial Commission[193]	New Mexico Oil Conservation Division[194]	Oil and Gas Conservation Commission[195]	California Geologic Energy Mgmt. Division (CalGEM) ORCEC[196]	Louisiana Department of Natural Resources	EPA	WV Department of Environmental Protection
	Agency Jurisdiction: Class VI Wells66	EPA (Primacy pending)	North Dakota Industrial Commission[197]	EPA	Wyoming Department of Environ. Quality[198]	EPA	EPA (Primacy pending)	EPA (Primacy pending)	EPA (Primacy pending)
Post-Closure Site Care and Liabilities	Class VI Post-Injection Site Care Requirements	Regulated by EPA Region 6. follows EPA 50- year mandate	Primacy: state can assume ownership after closure no earlier than 10 years.[199] Owners of active wells must pay into state-run CO_2Storage Facility Trust Fund to cover long-term monitoring costs.[200]	Regulated by EPA Region 6; follows EPA 50-year mandate[201]	Primacy: Post-injection site care shall be for a period of not less than 20 years[202]	Operator monitors for 100 years with updates every 5 years for Class VI wells to obtain LCFS Credit:[203] EPA 50 years mandate otherwise	The operator transfers the ownership to the state and is released from all duties, obligations, and liabilities after 10 years[204]	Regulated by EPA Region 9; follows EPA 50-year mandate	Regulated by EPA Region 3; follows EPA 50-year mandate State law allows transfer the ownership to the state after 10 years.[205]
	Allowing transfer of liability to the state	No	Yes	No	Yes	No	Yes	No	Yes
	Reopening liability in case of fraud or negligence	N/A	No, but penalties for violation	N/A	No	N/A	Yes	N/A	No
	Class VI Well Long-Term Liability	Under the Safe Drinking Water Act and according to EPA guidance, Class VI well closure does not necessarily release owners from future liability under tort or federal statutes including but not limited to CAA, CERCLA, and/or RCRA.							

The Environmental Defense Fund criticized[206] Wyoming's recently adopted legislation[cccc] noting that:

> *Technical experts know that if operators do competent work, the CO_2 will stay sequestered. There's no reason for a state to relieve operators of normal liability risks unless the state is trying to encourage incompetent work. Texas — which has not changed liability rules — seems to understand this. Wyoming, however, recently adopted legislation that undermines this important feature by absolving operators of liability (both civil law liability and ongoing regulatory requirements) as soon as a "closure certificate" is in place, even if it is later discovered that closure requirements have not been met.*

The future consequences of a state's taxpayers bearing responsibility for an environmental problem caused by the state assuming liability for a set of allegedly "plugged and abandoned" GS wells—wells that were not in fact properly plugged—could diminish public support for CCS as a valid climate tool.

Ensuring scale economies

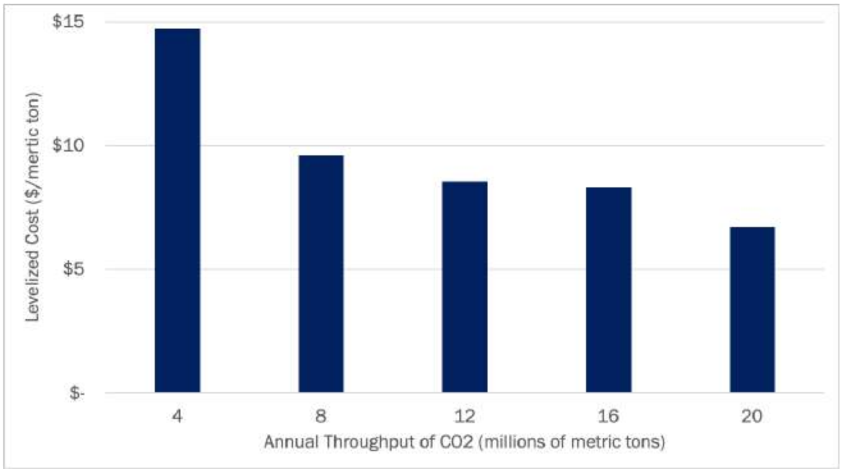
Geologic sequestration projects naturally benefit from scale economies, given that the capital cost to enable incrementally more storage capacity (or transportation capacity via pipeline) scales sub-linearly. Put simply, the capital costs needed for expansion increases only marginally compared to the capacity gains. For example, quadrupling the carrying capacity of a pipe (based on the cross-sectional area) results only in a doubling of the amount of steel (based on circumference). This results in a rapidly falling construction cost per metric ton of capacity as shown in **Figure 7**.[dddd,207]

Private developers will not be motivated to pursue GS projects unless there are adequate contracted flows of CO_2 to the site, the basis of which is their revenue. It will be very challenging for a private GS site developer to solidly establish this revenue flow, since so doing likely requires simultaneous coordination with several capture projects, each of which has its own individual issues of permitting, financing, and contracting—including for connecting pipelines.

[cccc] Referred to as Wyoming Senate File SF0047, or Enrolled Act No. 53 of the 2022 session of the Wyoming State Legislature.

[dddd] Note that costs don't fall smoothly because of interaction between available commercial pipe sizes and use of pumps to add compression when volumes fall between standard pipe diameters.

Figure 7
Falling Unit Cost per Pipeline Capacity as Scale Increases[208]



By contrast, a governmentally owned GS actor could take a longer view of establishing public utility-like disposal infrastructure with capacity based upon the estimated likely total volumes of CO_2 that could/would be capturable in a region. Without some forms of government intervention, it is not likely that geologic storage will reach the economies of scale needed for both transportation and geologic storage. Public ownership of regional CO_2 (at least initially) utilities may be necessary simply to share in the development risk, while also offering greater public control and learning opportunities.[209,210,211] Such public-private partnerships, such as in the case of Alberta Carbon Trunk Line (ACTL) located in Canada, offer a durable demand signal (see **Box 4**).

Box 4
Public-Private Partnerships for CCS

The Alberta Carbon Trunk Line (ACTL) located in Canada, which mapped out CO_2 supply, transportation, and disposition as part of an integrated project is a successful example of this approach.[212] The ACTL connects capture from industrial sources, conveyed along a (initially oversized) pipeline to geologic sequestration and EOR sites within the province of Alberta. Seeing the prospects of a carbon management system in part as an economic development project, the ACTL received significant federal and provincial funding to back private development, in exchange for fees to repay the public sector over the life of the project. As of 2022, the ACTL operates at 11% capacity, with prospects for expansion to ~50% by 2024.[213] Without significant public support, the ACTL would not have been able take advantage of scale economies, lowering the overall cost and increasing the access of multiple emissions sources to transportation and GS facilities.

Addressing the potential for monopoly market power in CCS infrastructure

CO_2 transportation and CO_2-EOR injection facilities have been developed over the past 50 years as geologic deposits of CO_2 were mined for use in oil and gas production. The associated pipelines were developed and underpinned by commercial arrangements among sophisticated business entities arranging inputs into industrial and production processes.[214] There was no need to economically regulate prices or service fees because CO_2 procurement and transportation was either an internal transfer of capital from one division within a firm to another, or a bilateral agreement between two private parties.

While an unregulated framework may have been appropriate for profitable commercial oil and gas production, it is likely not appropriate for a considerably larger CO_2 disposal-oriented industry. Economic regulation of CO_2 – the setting of rates for inter-and intrastate transportation and access to GS and its attendant rules to ensure fairness and competition – is an underdeveloped aspect of the CCS industry. Without proper attention, there is a risk of conditions that enable the initial developers to exercise market power; this might increase the overall cost of end-to-end CCS, for example, by extracting rents that do not sufficiently compensate the capture developer to the benefit of a transportation or GS operator.

Two federal agencies possess statutory authority over pipelines (and by extension, storage facilities): FERC and the Surface Transportation Board (STB.) under the Natural Gas Act and Interstate Commerce Act, respectively.[215] Both agencies, have however, effectively declined to assert jurisdiction over CO_2 pipelines and CO_2 storage facilities. With respect to FERC, in response to an inquiry by a pipeline operator in 1979, it rejected oversight of CO_2 transportation pipelines, given that CO_2 cannot be considered natural gas at the compositional level and is therefore not subject to FERC regulation. This ruling was later upheld in 1981 by the Interstate Commerce Commission.

Following the two FERC rulings, the U.S. Government Accountability Office (GAO), determined that the STB holds oversight authority of CO_2 transportation even though this office is primarily responsible for regulating interstate transportation by rail or pipeline of commodities “other than water, oil, or gas.” The STB has yet to be asked to hear a case involving the transportation of CO_2, so its oversight status remains unclear following the GAO decision.[216] While it would seem more likely that FERC would be the appropriate authority to regulate CO_2 transportation and sequestration assets from an economic regulatory perspective, it is also possible that Congress could establish a separate regulatory regime.[217]

Regardless of which agency has the relevant authorities, it will be necessary to address common carrier rules and standards, like many other kinds of network industries covered by the Interstate Commerce Act (ICA) and related amendments. A common carrier is obligated to provide service to any customer willing to enter contract terms, provide service to a customer making a reasonable request, and posting its terms of service and applying them uniformly.[218] Taken together, common carrier regulations could provide financial assurances and risk mitigation to developers across the value chain, while also signaling that carbon management is an expanding industry in need of such regulation. Development of economic regulation of CO_2 transportation and GS should be a matter of importance given the early stages of industrial hub development as part of overlapping BIL allocations.

Policy recommendations

Many policy measures are needed to mitigate all the barriers outlined in this discussion. EPA should provide certainty on the rules for permitting pipelines and UIC VI wells (Recommendations 4A, 4B). Each state should create one empowered coordinating body to manage all state-level CCS regulatory interfaces (Recommendation 4C). State coordinating bodies and legislatures need to develop clear, workable regulations and statutes concerning pore space unitization, post-closure liability and pipeline eminent domain (Recommendation 4D). Funding of NETL, USGS and other relevant agencies to support site characterization and improve the accuracy of commercial risk assessment tools for financial responsibility calculations should be prioritized (Recommendations 4E, 4F). Congress should consider authorizing innovative public private partnerships (including federal ownership stakes) in FOAK CCS pipeline and sequestration infrastructure to the extent so doing facilitates the construction of larger and less costly subsequent developments (Recommendations 4G). Congress should take up the issue of the appropriate federal role in permitting, eminent domain, and economic regulation for interstate pipelines and geologic sequestration sites (Recommendation 4H).

Recommendation 4A. EPA should release a detailed workflow for UIC VI permitting and promulgate best practices developed from past UIC II and VI experiences.

A detailed workflow—a formally outlined process of information submission, public comment, and approval—could reduce uncertainty for investors in terms of Class VI permitting. Further, building a database of past UIC experiences, using data residing within state natural resource and extraction departments, coupled with improved federal EPA and DOE NETL databases will better inform investors of the risks associated with permitting process. For example, aggregating and sharing industrial experience with UIC II well operation (e.g., injection) could help inform similar experiences (permitting and operations) for UIC VI operations.

Recommendation 4B. EPA should provide certainty on rules and pathways by which an existing Class II permit can be converted to a Class VI permit, thereby taking advantage of existing oil industry investments in infrastructure, surface facilities, and site characterization.

A key issue expressed by Class II operators is that there is a strong belief that conversion from an injection well for EOR to that for the purposes of geologic sequestration is technically achievable; the vagueness of EPA guidance is, however, a barrier to pursuing this option. This dovetails with making relevant information and data available, accessible, and usable, which combined could be of immense help to the GS industry. There could also be a role to play for the hydrogen hub or DAC hub initiatives, with DOE OCED and DOI USGS collaborating. EPA should also clarify that CO2 injected under the aegis of a Class II well would not be subject to RCRA definition of hazardous waste in the event a Class II well is converted to Class VI.

Recommendation 4C. State Governors should each create one empowered coordinating body to manage all state-level CCS regulatory interfaces.

Such interfaces include facility siting, eminent domain, pore space unitization, long-term liability requirements, etc.

Recommendation 4D. State coordinating bodies and legislatures each need to develop clear, workable regulations, and statutes concerning pore space unitization, post-closure liability, and pipeline eminent domain.

Funds made available through the BIL supporting state primacy of UIC VI wells for geologic sequestration of CO_2 (§40306), some BIL funds should also be allocated to efforts dedicated to resolving remaining pore space ownership questions, especially for split estates. For this purpose, appropriations made available in §40305 could support this work. These funds could then be granted to the appropriate department with each state government (Recommendation 4C) to develop the necessary capabilities.

Recommendation 4E. For first-of-a-kind projects, the federal government should consider a project-specific developer financial responsibility cap.

The White House could direct the Treasury, EPA, DOE, and DOI to convene a working group to explore options to address financial responsibility associated with geologic storage for first mover developers. A site may be very well characterized, but for nascent experience – especially in calibrating damage distributions – uncertainties may dictate that financial responsibility liabilities be set at high dollar values. This could be prohibitively expensive to induce FOAK project, especially considering all other risks in the value chain.

One template for financial assistance to backstop financial responsibility for FOAK GS projects is a layered approach, modeled on that which is employed in the nuclear power industry and codified within the Price-Anderson Act. The federal government can share risk with the operators of the projects and the industry through cooperative agreements.[219,220] In the event of an incident, the operator takes the first layer of responsibility up to a per-incident dollar limit. The second layer is for the federal government, which is capped at a limited amount. The remaining damage falls back on the operator. As this approach leaves some liability to the operators, the operators remain motivated for responsible behaviors compared to the transfer of liability to government approach.

As the carbon management industry matures, a new layer could be added between the first and the second, such that in the event cost exceeds the first limit; the cost of the new second layer is shared by the industry participants are part of a liability pooling agreement (like the Price-Anderson Act).

Recommendation 4F. Based upon scientific analysis of the risks involved, EPA should harmonize financial assurance requirements across UIC I Hazardous Waste, UIC II and UIC VI.

EPA's approach to estimating risks of and financial assurance required for Class VI injections of CO_2 should be consistent with the scientific/probabilistic analysis of risks to property, drinking water, or public health. Perhaps without intent, current practice appears to treat injection of pure CO_2 into the subsurface in Class VI wells as in need of more post-closure effort than either Class II injection of CO_2 for oil and gas production (which includes risk of hydrocarbon intrusion into USDW) or Class I injection of hazardous wastes.

Recommendation 4G. Congress should consider authorizing innovative public private partnerships (including federal ownership stakes) in FOAK CCS pipeline and sequestration infrastructure to extent so doing facilitates the construction of larger and less costly subsequent developments.

In this context, a recent study of Labor Energy Partnership suggested four options for ownership and management structures for CO_2 storage business models: private sector model, utility model, public authority model, and quasi-federal government model (**Table 14**).[221] A creation of CO_2 management entity, for example, modeled after quasi-federal government entities, could significantly mitigate the risks associated with long-term liabilities, permitting, and siting, since the entity is responsible for building CO_2 storage facilities based on estimates of future capacity demand and working with the private sector and government entities for financing, siting and permitting. This model could also address the issues of long-term liability by transferring the liability for the CO_2 to the government from the project operators that capture the CO_2.

Table 14

Possible Ownership and Management Structures for CO_2 Storage Business Models[222]

MODEL TYPE	OWNERSHIP	OPERATION	FINANCING	LIABILITY	PERMITTING	SITING	ANALOGS
PRIVATE SECTOR MODEL	Private	Private	Private with government subsidy	Private	Works with Governments	Works with Governments	Current CCS Projects (e.g., ADM*, Petra Nova)
UTILITY MODEL	Government chartered, Private	Private	Private with government subsidy, Government regulated	Private, Government insurance model, Obligation to serve	Works with governments	Works with governments	Investor-owned interstate utilities in electricity, gas, telecoms, etc.
PUBLIC AUTHORITY MODEL	State/local government, interstate compact	Private, Government	Government, Private partners	Government, Obligation to serve	Eminent domain authority, Works with governments	Eminent domain authority, Works with governments	Public utilities for electricity, etc.; interstate or intermunicipal agencies (e.g., DC WASA*, Port Authority); federal quasi-corporations (e.g., Amtrak, USPS)
QUASI-FEDERAL GOV'T MODEL	Federal Government	Government, Contractors	Government, Private partners	Government, Regional or national jurisdiction	Eminent domain authority, Works with governments	Eminent domain authority, Works with governments	TVA, Power Marketing Administrations (e.g., BPA, WAPA, SWPA*)
***ADM=ARCHER DANIELS MIDLAND; DC WASA = DISTRICT OF COLUMBIA WATER AND SEWER AUTHORITY; TVA = TENNESSEE VALLEY AUTHORITY; BPA = BONNEVILLE POWER ADMINISTRATION; WAPA = WESTERN AREA POWER ADMINISTRATION; SWPA = SOUTHWESTERN POWER ADMINISTRATION**							

Recommendation 4H. Congress should take up the issue of the appropriate federal role in permitting, eminent domain, and economic regulation for interstate pipelines and geologic sequestration sites.

Consistent with the Utilizing Significant Emissions with Innovative Technologies (USE IT) Act, CEQ announced its plan to convene the relevant federal and state agencies responsible for the permitting of CO_2 pipelines to assess the opportunities for improvement in its guidance published in February 2022.[223] In this context, the CEQ announced the launch of two task forces that will make recommendations to other federal agencies on more efficient permitting of CCUS projects and pipelines--one task force focusing on federal lands, and the other focusing on non-federal lands -- in July 2022.[224] The task forces will identify gaps in current state and federal regulatory frameworks, inventory federal and state approaches to facilitate review of CCUS projects and pipelines, and develop common models for state-level pipeline regulations and guidelines. This effort should lead to the establishment of a federal regulatory framework for all relevant government agencies to mitigate the risks of siting interstate CO_2 pipelines. There have been extensive analyses on possible models for regulatory frameworks for interstate CO_2 pipelines, including natural gas pipeline model, oil pipeline model, federal back stop authority model, and interstate compacts.[225]

Congress could be informed by DOE's recent funding of FEED studies for regional scale CO_2 transport projects.[226] In this regard, the applicants to the funding program are required to perform a regulatory plan analysis, including their plans to engage with state and federal regulators and to receive required approvals for the projects. Using this and other information, the regulatory plan analyses submitted by the applicants could inform how current regulatory schemes for siting and permitting CO_2 pipelines affect the feasibility and timeline of the project and offer implications on potential changes of regulatory schemes for interstate CO_2 pipelines.

Economic/rate regulation of CO_2 transportation and GS facilities may be required to bring order to the carbon management industry, work against aggregation of market power, and enable fair and competitive intra-and-interstate CO_2 flows. Common carrier rules, those that govern other network industries such as interstate natural gas pipelines and electric transmission lines, are fundamental to achieving CCS at scale and encourage developers beyond first movers.

THEME 5. SITING ANALYSIS FOR A CARBON CAPTURE PROJECT NEEDS TO ADDRESS FENCELINE COMMUNITY HEALTH ISSUES

Public involvement process should incorporate calculation and disclosure of both the risks and benefits of carbon capture retrofit projects

Overview

Environmental justice groups speaking for fenceline communities have voiced two main sets of objections to carbon capture (CC) retrofit projects. If not adequately addressed by industry proponents, these objections will increasingly tarnish public perceptions of CCS as a pollution control technology. These objections focus on:

- Net emissions associated with the installation of carbon capture equipment: One set of objections is about the incremental emissions associated with the new carbon capture equipment itself, including GHGs, CAPs, and HAPs, and whether they could substantially negate the benefits of capturing CO_2 from the original polluting vent stack. This concern – a technical matter of engineering, air dispersion modeling, and toxicology – may be reinforced by a lack of publicly accessible research and reporting on the subject. While data are limited, the following analysis suggests that installation of CC equipment may lead to net emissions reductions, but that these reductions vary depending on the type and condition of the equipment to which CCS is added.
- The potential perpetuation of fossil fuel use and highly polluting industries: The second set of objections relates to fears that adding any CCS equipment to an emitter facility not only may extend the life of that individual facility but that CCS deployment at scale may perpetuate fossil fuel extraction and highly emitting industries. Analysis in this

study concludes that these concerns – a matter of industry competitive analysis – are not justified in most cases.

This chapter makes federal research recommendations that address the technical issues associated with the first objection. The second claim, as we will discuss, appears to require political leadership more than federal research or policy.

CC Objection #1: Full costs and benefits of CC equipment in retrofits

To address the first point issue on the CC equipment and the host emitting equipment, there needs to be improved transparency in siting CC projects in local communities. In the case of CC retrofit projects, the present federal Clean Air Act framework for siting, as that Act is enforced pursuant to delegation to the various states, requires disclosures only about the direct emissions of the new CC equipment without consideration of the combined impacts of new CC equipment and the old unabated equipment, as discussed in more detail below. This narrowly focused disclosure could lead to a lack of understanding of the environmental benefits of a retrofit.

A significant lack of available data exacerbates skepticism from community groups and citizen advocates. A research team (of which one of the study authors was a member) spent two years and significant resources on consulting and legal fees on investigating this topic and found that obtaining current emissions and engineering data for the proposed new abatement devices was exceedingly difficult.[eeee]

While most Federal analytical attention has been paid to efficiently integrating carbon capture into *new* plants, beyond greenfield hydrogen projects with carbon capture, most CCS development and project scoping work in 2022 is focused on *existing* industrial and electricity generation assets. Examples include existing blast furnace-basic oxygen furnace (BF-BOF) steel mills, pulp and paper facilities, refineries, cement kilns, ethanol facilities, hydrogen production using steam methane reforming (SMR), and newer vintage pulverized coal and NGCC power plants.

[eeee] Referring to work for upcoming Clean Air Task Force's research paper. The CATF team had to file dozens of public information requests via attorneys to obtain basic data from air quality regulators. A significant portion of the requests were simply ignored. The team learned that even when continuous emissions monitoring systems are required on vent stacks, the actual data is not reported to regulators (other than SO_2 and NO_x data for grid-serving power plants). Rather, emitters must self-report instances where hourly or weekly limits are violated -- but not the actual instrument readings.

The current permitting system, including NEPA/EIS proceedings, is not designed to measure the tradeoffs associated with adding CCS to existing facilities. Such retrofit projects are problematic because they involve constructing a major new installation costing hundreds of millions of dollars to abate the pollution of the existing host/emitter plant. The extra costs, inevitable emissions, energy and water consumption, and land use must be weighed against the environmental benefits associated with abating the host plant emissions. Unfortunately, these tradeoffs are not currently considered to the extent necessary for properly evaluating the costs and benefits of a new CCS installation.

The evaluation and permitting of CC-retrofit projects must be consistent, science-based, and transparent. The environmental risks/benefits and human health risks/benefits need to be clearly weighed and tradeoffs addressed. The root cause appears to be that current permitting schemes have been, of necessity, grafted onto legacy existing systems and precedents that may not be flexible enough for scaling up CCS nationally.

CC Objection #2: Perpetuation of fossil fuel consumption as a result of adding CCS to some or all equipment at a facility

This is a multilayered question. Part of it relates to the fenceline community and its relationship with the emitter facility. The primary ways in which adding CCS pollution control equipment could perpetuate the survival of the host facility include either a) adding CCS materially increases the operating cash flows of the plant (unlikely in most cases) or b) CCS solves an environmental compliance issue that would, absent CCS, cause the plant to shut down (unlikely since GHG emissions are not subject to a compliance regime). The major GHG-emitting plants in heavy industry are often vast, sprawling, multi-billion-dollar assets that have been in continuous operation for a century or longer, e.g., in the case of integrated blast furnace steel mills and petroleum refineries. These facilities are expected to remain in continuous operation until a new production method arises that is both cheaper and lower in carbon intensity (e.g., a cheaper and cleaner substitute for blast furnaces), an end to market demand for the product (e.g., banning internal combustion engines reduced demand for refineries), or tight new emissions rules force the owner to shut down the old plant and perhaps rebuild at a new site.

This topic needs to be addressed in public discussion, but it does not seem to call for policy changes so much as it calls for clear, sensitive, coherent political leadership.

Link to investability

The nexus of these issues to investability is that the structure of current permitting regimes—outlined in the balance of this section—could lead to worse environmental performance and economics, coupled with a higher cost of financing. Further, the current permitting regimes are inherently non-transparent, likely increasing the probability of objections to carbon capture or geologic sequestration projects by local communities. These objections may or may not prevail procedurally or legally, but they may undermine an investor's willingness to participate in a project, given the potential for damaging its reputation. Finally, the extent that CC or GS projects require federal agency actions that create a NEPA exposure (i.e., may require a Finding of No Significant Impact, Environmental Assessment, or Environmental Impact Statement) may make the NEPA process significantly more difficult for project developers without providing incremental benefits to the public or the environment.

Scope limitations

Since significant, publicly available engineering work remains to be done, the scope of this study does not include a comprehensive analysis of environmental justice-related permitting issues or proposed solutions.[ffff] However, this section provides an initial discussion of these challenges to shed light on their complexity and importance from an investment quality perspective. These challenges are practical, material issues that have arisen in every CC-retrofit or GS project to date and have been flagged by active developers through informational interviews in support of this report. This section outlines issues and suggests broad approaches to solutions.

[ffff] A complete treatment of the issues would necessitate a concerted effort by attorneys and engineers who are specialists in the areas of air permitting in the case of CC, and in the Underground Injection Control system (UIC) in the case of GS.

Carbon Capture Objection #1: Benefits and costs of emissions before and after a carbon capture retrofit

Developers are motivated to permit carbon capture in isolation, which means there is no comprehensive analysis

Developers are motivated to analyze and permit CC in isolation from the host facility because they wish to avoid "reopening permits" for that facility. The rules are intricate, and this analysis does not propose fundamental changes to those rules.

Developers/facility owners are motivated to treat the CC equipment as a brand-new stack and to avoid discussing the existing stack. The two pieces of equipment must, however, operate together to obtain the greatest GHG mitigation (and concomitant reductions in other pollutants) at the lowest capital and operating costs with the lowest incremental emissions. Clean Air Act regulations in many cases allow the developer/facility owner to focus permitting work on the new CC equipment alone, which is acceptable for the limited purposes of environmental compliance. However, in the larger view of public acceptance, this approach makes it challenging to do a comprehensive cost/benefit evaluation of a carbon capture project across the entire spectrum of emissions, including GHGs, CAPs, and HAPs.

Generally, U.S. polluters do not need to continuously update their pollution control technology. Rather, in the U.S., once an emitter facility initially obtains an air emissions permit for an individual vent stack within an emitter facility, the mass- and concentration-based emissions performance standards set at the original permitting date govern that vent stack. This is the case unless there is either a supervening change in law (e.g., the adoption of Acid Rain Rules that require existing power plants to reduce sulfur emissions notwithstanding existing permit limits) or the emitter undertakes a "major modification," defined as "*any physical change in or change in the method of operation of a major stationary source that would result in a significant emissions increase...of a regulated*

NSR pollutant...and a significant net emission increase of that pollutant from the major stationary source." [gggg,227]

In case of a "major modification" to a stationary source, the host facility owner must effectively obtain a new set of air permits for the associated vent stacks in a public process. In such a situation, the owner will be required to install either the *Best Available Control Technology* in geographies that are currently in compliance with EPA ambient air quality standards, or equipment that accomplishes the Lowest Available Emissions Rate in non-attainment areas.

The legal implications of triggering "major modification" are specialized, depending on various factors including levels of gross and net emissions changes and the degree to which the CC system is consolidated into the overall pre-existing host plant permit. Moreover, reductions in emissions that are considered in determining whether a "significant net emissions increase" has occurred in the second branch of the "major modification" test above, include only "enforceable" reductions, which might or might not include engineering-driven CAP decreases consequent to the operation of CC systems.[228] Existing plant owners are likely to take no chances on the possible re-examination of the old permits. Indeed, as one environmental consulting firm notes:

> *For almost 30 years now, the term "major modification" has struck fear into the hearts of environmental managers associated with facilities that are classified as "major stationary sources" under the NSR regulations. In many instances, such fear is valid because the air permitting path associated with major modifications can be sufficiently complicated and fraught with uncertainty that the very viability of a given project could be threatened.*[229]

If emitters seek to avoid re-examination of existing permits when they install CC systems, they may inadvertently obscure the public health and GHG reduction *benefits* of the carbon capture project.

[gggg] Coal burning power plants were subjected to New Source Performance Standards in 1971 with limits of 1.2 lbs SO2 per MMBtu for solid fuel steam generators (e.g., coal). https://www.epa.gov/sites/default/files/2015-07/documents/36fedreg24876.pdf The Acid Rain Program was adopted in 1990, setting nationwide goals for reduction in emissions of mass of SO2 nationally. The program seems to have tightened emissions limits below levels of the NSPS: "Initiated in 2000, Phase II extended coverage to nearly all coal-fired power plants with greater than 25 megawatts of capacity. Overall, Phase II covered more than 3,500 units. In Phase II, regulators allocated allowances according to a more stringent formula equal to the lesser of 1.2 pounds of SO2 per million Btus, or a plant's 1985 recorded emissions rate multiplied by its average heat input for 1985–1987." Quote from https://www.rff.org/publications/issue-briefs/the-us-environmental-protection-agencys-acid-rain-program/#:~:text=Overview,below%201980%20levels%20by%202010.

Examples of permitting and analyzing carbon capture in isolation

Two major U.S. pulverized coal power plant projects, NRG's Petra Nova project (completed) and Minnkota Power Cooperative's Project Tundra (2023 construction, expected), analyzed capture projects in isolation from the underlying coal generating units whose gaseous waste the capture projects would treat. This report makes no criticism of either the projects or the regulators; rather, we assert that the present system leaves fenceline communities without enough information to confidently evaluate the construction of CC projects in their neighborhoods.

In a review of Petra Nova's federal EIS and a variety of Texas Council on Environmental Quality (TCEQ) filings on Petra Nova, no comprehensive "before and after" analysis was provided comparing the existing host plant (W. A. Parish Unit 8) and the Petra Nova related facilities. The related facilities include the new capture unit itself and a newly built gas-fired combined heat and power unit that supplies steam and electricity to the capture unit as well as electricity to the ERCOT grid.[hhhh] Though NRG did not state a motivation for its approach, most knowledgeable observers infer from NRG's actions that it sought to avoid any chance of opening or re-examining W. A. Parish Unit 8's permits.

The logical consequence of analytically separating the host from the capture plant in a CC permitting process is a failure to comprehensively examine the combined system (host and new equipment) or the net reduction of CO_2 that was the motivation for the project. Crucially, while there is nothing inherently incorrect about this narrow permitting approach, it does mean that the public sees an incomplete picture of the gross incremental emissions from the capture plant without seeing the offsetting emissions reductions. As a result, the public may perceive that the project will *increase* emissions when in fact installation of CC equipment *decreases* total facility emissions. In its Preliminary Determination Summary for Petra Nova, the TCEQ states:

> *The Demonstration Unit will treat a slipstream of approximately 30% of the flue gas from the existing Unit 8 (coal/gas-fired utility boiler), emission point number (EPN) WAP8, upstream of the stack and downstream of the existing baghouse and Wet Flue Gas Desulfurization (WFGD) system. Unit 8 is currently authorized under Permit*

[hhhh] Materials studied relating to Petra Nova included the original Federal Environmental Impact Statement of February 2013 (DOE/EIS-0473); Texas Commission on Environmental Quality (TCEQ) Preliminary Determination Summary, NRG Texas Power, LLC, Permit Numbers 98664, N138, and PSDTX1268; and U.S. DOE National Energy Technology Laboratory, W.A. Parish Post-Combustion CO2 Capture and Sequestration Demonstration Project, Final Scientific/Technical Report, March 31, 2020.

> *Numbers 7704 and PSDTX234M2. . . The extracted flue gas from EPN WAP8 being routed to the Demonstration Unit EPN SCRUB will contain the following pollutant emissions: NO_x, CO, VOC, SO_2, H_2SO_4, [redaction], HF, HCl, and particulate matter ($PM/PM_{10}/PM_{2.5}$).* ***These emissions will continue to be authorized under NSR Permit Nos. 7704 and PSDTX234M2 and are not considered project emission increases.*** *[emphasis added]*[230]

In the same vein, if residents have worries about little-known toxic emissions, redacted text such as the following would arouse, not calm, but concerns:

> [redacted]*-In the Demonstration Unit, a small quantity of* [redacted] *is emitted from the scrubber stack. The scrubber solvent degrades under normal conditions to form* [redacted]*This emission is mitigated by washing the treated flue gas in multiple stages. In addition, the* [redacted] *emission is mitigated by proper design, plant operation, and solvent maintenance to minimize solvent degradation. BACT is satisfied. [Redacted in original]*[231]

Similarly, Project Tundra's filings with the North Dakota Division of Air Quality solely deal with the direct gross emissions of the capture units and steam boilers, without any meaningful discussion of the overall impact on CO_2 or CAP emissions from the site, including the two pulverized coal generating units at the Milton R. Young plant site whose exhaust gases are treated by the capture unit. [232]

Why is this analytical isolation a problem?

The analytical isolation of a host facility's unabated emissions from the impacts of the proposed carbon capture units deprives the public and policymakers of real-world evidence of the validity of CCS as an important tool both to reduce CO_2 emissions and in many cases, to reduce CAP emissions. CCS has challenges in terms of broad public acceptance among non-engineers. These challenges, described below, are exacerbated by the limited environmental analysis of CCS projects that are available to the public.

One line of argument against CCS relates to the claims that could be summarized as "CCS is a cure that is worse than the disease." This logic frequently implies or directly states four different sub-claims: a) the GHG emissions from providing heat and electricity for the capture facilities substantially erode the GHG benefits of carbon capture; b) carbon capture units have no net beneficial impact on existing host facility emissions of conventional pollutants such as SO_X, NO_X, and particulates; c) CCS projects are likely to emit HAPs (such as fugitive amine scrubbing chemicals or aldehydes) with deleterious public health impacts that outweigh the other benefits; and d) a relatively little-studied family of carcinogens in the nitrosamine class of chemicals are generated at dangerous levels.

Indeed, total *fuel* use always rises when emissions controls—sewage treatment, automotive catalytic converters, or electrostatic precipitators--are added to reduce/control pollution. For example, one environmental organization opposed to CCS states:

> *[C]arbon capture and sequestration (CCS) infrastructure also run[s] the risk of aggravating local air and water pollution impacts and propping up a racist, fossil-fuel powered energy system... **CCS technology captures CO_2 but does not capture other air pollutants from combustion sites**, and increased energy requirements of the process itself can lead to **greater overall fuel use and increased emissions for some air pollutants**. If no additional air pollution control investments are made, widespread adoption of CCS could lead to increases in air pollution-related mortality and higher social costs.[233] [emphasis added]*

Additional examples illustrate opposition to CCS: a recent letter from an environmental NGO to California's Governor Newsom called for removing CCS from the policy toolkit for reducing oil refinery emissions, making the same basic assertions. The letter asks for the "elimination of carbon capture as a strategy to reduce emissions at California's refineries as it would prolong adverse health impacts of refinery pollution and introduces other hazardous conditions."[234] In another example, the White House Environmental Justice Advisory Committee recommendations document of May 2021 lists CCUS in the second spot on WHEJAC's roster of "Examples of The Types of Projects That Will Not Benefit a Community."[235]

A call to action: what would comprehensive analysis for community disclosure look like?

Perhaps the most urgent step for improving disclosure of the risks and benefits posed by CCS projects is to enable public consideration of the *net* emissions associated with the entire facility rather than a narrower focus on the *gross* emissions from only the carbon capture equipment. A prospective analysis for community disclosure would model a comparison of GHG, CAP, and HAP stack emissions for the host facility in the base case against a combined proposed case that encompasses the host (including any changes at the host facility) plus all new equipment added to implement carbon capture. Then those stack emissions, before and after, would be entered into air pollution/dispersion modeling systems, with population exposures calculated. Finally, public health experts would project population morbidity and mortality, both for the status quo and if the CC system were to be installed. As noted, undertaking such community disclosure does not require a change in the Clean Air Act; it would, however, require a different approach on the part of regulators and project proponents.

There is a lack of precedent in these circumstance as such comprehensive analysis is not done in normal course of project development, is not typically required by law, and is expensive and time-consuming to perform. We have found no published studies that have investigated the topic at the needed level of engineering specificity. One new study, however, executed by the Clean Air Task Force (CATF), a Boston-based international environmental group, offers some insights that could inform a comprehensive analysis that DOE or EPA could undertake.[iiii] The CATF report is expected to be released in 2023, but in view of the level of interest in this topic, CATF permitted EFI analysts to review and reference the unpublished draft report and raw data.

The issues in the CATF study are divided into four parts to focus on key areas of controversy. The primary engineering scoping underlying the CATF report was the first two issues, though CATF is expanding the report to comment on the 3rd and 4th issues. The discussion of the 3rd and 4th issues is based on a review of the published literature. The four areas are:

1. Whether the GHG emissions from extra energy steam and electricity requirements of carbon capture project equipment negate the benefits of CC;
2. Whether the CAP emissions from extra energy steam and electricity requirements of carbon capture project equipment negate the benefits of CC;
3. The specific issue of increased VOCs that result from using amine solvent capture technology; and
4. The understudied, but much discussed, issue of nitrosamine compound[jjjj] formation from solvent breakdown.

[iiii] Jeff Brown, the lead author of this report, is a co-author of the CATF study, which has been ongoing since late 2019. Here, the findings from the CATF report are summarized and homogenized to preview the type of detailed analysis that would address many misperceptions regarding the pros and cons of CCS from a lifecycle analysis and air pollution/epidemiology standpoint.

[jjjj] There are dozens of nitrosamine (and nitramine) compounds that can be formed to the extent that amine solvents (such as DEA and MDEA) contact nitrous acid in the absorber tower of a carbon scrubbing system. Some are strongly carcinogenic, and some are not. For the most part, the total nitrosamine & nitramine emissions are so small that they fall below levels detectable outside laboratories (i.e., billionths of grams per cubic meter of stack gas).

GHG emissions

CATF reviewed net changes to both GHG and CAP emissions if CCS were installed at two cement plants and two oil refinery fluid catalytic cracking units (FCCU), one in Texas, the other in California. The study focused on cement plants and FCCUs because both types of emitters typically burn carbon-intensive fuels and often have relatively old air permits that allow levels of CAP emissions (i.e., "conventional" non-GHG pollutants) that are typically higher than 2022 New Source Performance Standards. The selected sites offer interesting case studies of both net GHG and CAP impacts associated with carbon capture retrofits.[kkkk]

For the limited purposes of EFI's study, the site-specific estimates of gross and net emissions in the CATF analysis were aggregated to create a before-and-after emissions profile for a composite project with pre-abatement emissions of one million short tons of CO_2/year.[llll] The results (CO_2 only) are shown below in **Table 15a**.[mmmm]

CATF's analysis fully accounted for GHG emissions from natural gas steam boilers added to provide process steam for the capture units. In CATF's analysis, electric parasitic loads were not included based on an assumption that electricity was bought from the local grid. Electricity emissions per MWh vary widely by utility and will fall over time as the electric sector decarbonizes. In contrast, natural gas boiler emissions are fixed at project construction.[nnnn]

1. Row A shows existing unabated CO_2, which is one million short tons (s-tons) per year given results normalized to that quantum.

[kkkk] The number of potential case studies was inherently limited because of the significant difficulties in obtaining existing GHG and CAP emissions data from the relevant vent stacks and the expense of hiring engineering consultants to design site-specific CC configurations and air modelers to estimate air pollution dispersions, ground concentrations, and health impacts. Thus, results from the CATF study should be viewed as a representative of the insights that could be obtained in a more comprehensive effort.

[llll] That is, the total pre-abatement CO_2 emitted by all four projects was 5.9 million short tons/year. All the emissions were added, before and after, and were divided by 5.9 to get a normalized composite project for a 1.0 million short ton/year emitter.

[mmmm] CATF used short tons because virtually all the source data were in those units.

[nnnn] If electricity were provided by a utility that had a mix of 50% renewables/nuclear/hydro and 50% combined cycle natural gas plants, that electric usage would have had a typical impact of ~20,000 additional s-tons of GHG (reducing % GHG benefits to -81%) and ~18 s-tons/year of NO_x (reducing % NO_x benefits to -8%). Sulfur emissions would have been unaffected. Grid-level particulate data not available. Source for calculations was data for NGCC power plants in the U.S. in 2021 from ABB Energy Velocity database for universe of NGCCs with heat rate <7,000 Btu/MWh.

2. Row B shows that gross CO_2 emissions rise by about 1/5th once CO_2 pollution control equipment is added, with total gross emissions rising to 1.2 million s-tons per year in Row C.[oooo]
3. Row D shows just over one million s-tons per year removed by the new CC equipment, resulting in an 83% net reduction in CO_2 compared to the original unabated plant (Row G).

In short, rigorous analysis shows an 83% net CO_2 reduction from CC retrofits on cement plants/refineries, clearly refuting the assertion that the energy load of running the carbon capture negates the GHG reduction impact of the carbon capture project. In other words, while gross emissions and fuel use rise, net CO_2 emissions substantially decrease when carbon capture units are installed.

Table 15a

Composite Result from Four Carbon Capture Retrofits in Cement/Refining (all mass reported in s-tons) (pre-publication data)

Row	Impact of CCS per 1 million s-tons captured of CO_2	CO_2
A	Current unabated host facilities	1,000,000
B	Additions from steam boilers to serve capture	208,598
C= A+B	Total emissions	1,208,598
D	Removal in carbon capture units	(1,036,646)
E= C-D	Net emissions after pre-treatment & CC	171,952
F	Net tons per year reduction vs. 1mm s-tons/yr pre-abatement CO_2	(828,048)
G=F/A	Net percentage reductions from pre-abatement CO_2	-83%

Criteria Air Pollutant Net Changes after Installation of CC

Table 15b follows the same general format, but adds four key local air pollutants: NO_x, SO_2, filterable Particulate Matter (PM), and condensable PM. Both PM measurements are for the smaller $PM_{2.5}$, pollutants that are more dangerous to human health

[oooo] Note this ~20% gross emissions increased is on the high side of the typical range because CATF's engineer did not have access to data for more efficient proprietary CO_2 scrubbing formulations and thus had to use generic specifications. Proprietary solvents typically have parasitic steam loads in the ~15% range. [Based on author's confidential information from various engineering projects.]

1. Row A shows existing unabated NO_x, SO_2, Filterable PMs, and Condensable PMs. The CAP emissions for the representative composite one million short tons/year CO_2 emitter include 961 short tons/year NO_x, 569 short tons/year SO_2, and combined 176 short tons/year filterable and condensable PM. To put a single pollutant into context, the 569 short tons/year of SO_2 would have been approximately 10% of the total San Francisco Bay area stationary SO_2 in 2017 or 18% for the LA area in 2017.[pppp]
2. Row B shows that gross emissions of all four CAPs do not rise materially with the addition of new steam boilers. Row C gives total gross CAP emissions. Note that this low CAP impact is to be expected since the CC project steam needs are met by installing state-of-the-art natural gas steam-fired boilers with BACT NO_x controls and because natural gas contains virtually no SO_2 or PM-generating contaminants.
3. Row D shows the impact of new pretreatment equipment, i.e., new pollution control equipment located upstream of the inlet to the CC installation proper. This new pollution control equipment must be added—as an engineering necessity rather than as a regulatory compliance imperative---to reduce contamination in flue gases inbound to the CC system to protect the CC system and the purity of the system's operating process chemicals. The most significant reductions are of SO_2 and PMs, but there are also minor NO_x reductions. CATF's engineering consultants were directed only to add such equipment as required to protect the safe/efficient operations of the CC system—hence this new pollution control equipment is not added for legal compliance or community benefit purposes.
4. Additional CAP removal from normal operation of the CC system is shown in Row E. These amounts are partly from normal "polishing" to remove even more pollutants and partly from CAPs being dissolved into the CO_2 scrubbing solution in the CO_2 absorber unit.
5. Row F shows the total tonnage removed (per one million tons of original CO_2 emissions).
6. Row I shows net reductions of 10% of NO_x, 96% of SO_2, 96% of filterable PMs, and 46% of condensable PMs.

[pppp] EFI calculations from downloading 2017 National Emissions Inventory at facility level for California and additional filtering to obtain totals for LA Basin and Bay Area.

Table 15b

Composite Result from Four Carbon Capture Retrofits in Cement/Refining (all mass reported in s-tons) (pre-publication data)

Row	Impact of CCS per 1 million s-tons captured of CO_2	CO_2	NO_x	SO_2	Filterable PM	Condensable PM
A	Current unabated host facilities	1,000,000	960.5	568.7	73.6	102.8
B	Additions from steam boilers to serve capture	208,598	2.5	3.1		
C= A+B	Total emissions	1,208,598	963.0	571.8	73.6	102.8
D	Removal in pre-treatment added to hosts		-48.6	-476.4	-68.5	-47
E	Removal in carbon capture units	-1,036,646	-42.9	-70.7	-2.0	
F= D+E	Total removals	-1,036,646	-91.5	-547.1	-71	-47
G= C-F	Net emissions after pre-treatment & CC	171,952	871.5	24.7	3.1	55.8
H= G-A	Net tons per year reduction vs. 1mm s-tpy pre-abatement CO_2	-828,048	-91.5	-547.1	-71	-47
I= H/A	Net percentage reductions from pre-abatement CO_2	-83%	-10%	-96%	-96%	-46%

The results from this case analysis clearly contradict the generalized assertion that CC systems do little to improve local air pollution. Instead, the more contaminated the original exhaust, the more the CC project must do to clean it up. Of course, if the original exhaust (i.e., the unabated stack gases of the host) had virtually no SO_2, NO_x, or PMs there would be little CAP co-benefit; but in such a case, the local community may also be less concerned about CCS retrofits.

The actual changes in emissions mass at the top of the vent stack are important, but a greater concern is the dispersion of pollutants into local airsheds and the impact on residents. CATF used air dispersion models to examine the results of the four cases and then analyzed the health impacts of population exposures with EPA software. Four similarly sized CCS projects and associated CAP cleanup yielded very different health impacts; the biggest health benefits occurred when the original host was a major polluter and was sited in a major population center. Smaller health benefits arose when the opposite was true – a relatively low-polluting host in a rural area with a low population density. **Table 16** shows the aggregated total health benefits for the four projects.

Table 16

Summary of Health Impact Assessment for Four Case Studies of CCS and Associated CAP Reductions

	Lives Saved per Year	Annual $ Health Benefits
Low Case	38	$419 million
High Case	85	$943 million

Two other sets of emissions, VOCs and nitrosamines have raised concerns, though the CATF had not yet fully addressed these specifically in the early draft we reviewed. Below is an examination of these issues using literature or permit applications that are in the public domain.

Volatile Organic Compounds, including certain HAP emissions from carbon capture projects

The two main sources of incremental VOCs are aldehydes (from the breakdown of amine solvent in the presence of oxygen) and trace losses of amine solvent to the atmosphere from various points in the carbon capture process. While not directly comparable to the situations examined in the CATF study, the Project Tundra air permits (on coal combustion CC) could illustrate the overall magnitude of such emissions. Project Tundra's scope, capturing ~four million short tons/year of CO_2, is 4x that of the representative project (**Tables 15a** and **15b**). Tundra expects to emit five short tons/year of acetaldehyde, two short tons/year of formaldehyde, and 9.6 short tons/year of escaped amine solvent.

1. In Project Tundra's air permits analysis, these levels of VOC emissions were found to be too small to constitute a Significant Emissions Rate (SER) that would have triggered a Prevention of Significant Deterioration analysis. [236]
2. Two of the compounds, acetaldehyde, and formaldehyde (but not Tundra's amine solvent), are HAPs. However, the air toxics analysis conducted by Tundra's developer showed the acetaldehyde concentration to be approximately 1/5,000th of "Guideline Concentrations" (GC) and formaldehyde to be 1/75th of GCs. The GCs of the air regulator were set at a level low enough to reduce the likelihood of an individual generating cancer from exposure to the substance, over 70 years, at the point of greatest ground-level concentration in the vicinity of the stack to below 1 in 100,000.[237]

In short, while increases in VOCs and certain HAPs associated with the new CC equipment did occur, thus suggesting that CCS critics' claim is technically correct, the amounts of the gross increases were too small to trigger regulatory responses and are not considered dangerous to public health.

Nitrosamines and nitramines

Another set of compounds of concern that could be emitted from CC systems are the nitrosamine and nitramine family of chemicals, with nitrosamines being cited as the more carcinogenic of the two. Nitrosamines can form if the amine solvent used to capture CO_2 is degraded by trace nitrogen dioxide (NO_2) in the treated flue gas stream.[qqqq][238] A host of issues must still be researched to adequately weigh the health risks from possible nitrosamine formation against the health benefits of reducing other pollutants when CC systems are deployed.

A handful of studies, mostly from European and Scandinavian sources, have examined this issue and have concluded, using conservative assumptions, that the risk from emitted nitrosamines is negligible. In connection with a cement industry carbon capture project proposed to be built in Brevik, Norway, Multiconsult (a Norwegian engineering firm) estimated three values: 1) the mass of nitrosamines that would be generated and emitted, 2) the highest concentration levels at ground level near the plant, and 3) how concentrations compared to limits set by the Norwegian Institute of Public Health (NIPH). The report concluded that exposure levels were approximately 1/250th of NIPH's "proposed limit values."

> *Maximum calculated levels of nitramines/nitrosamines (total approx. 0.001 ng / m^3 for nitramines and nitrosamines combined) show that no land areas will have concentrations in air that are close to the proposed limit values from the Norwegian Institute of Public Health at 0.3 ng / m^3. The calculated maximum values amount to less than 0.4% of the recommended limit value.* [239]

The conclusion above notwithstanding, the uncertainties surrounding this topic are numerous:

[qqqq] Note that various articles in the literature show that different solvent formulations appear to have very different degrees of reactivity to NO2 and to have very different speciation of nitrosamines in the breakdown products. There may be operating cost vs. nitrosamine emissions tradeoffs that should be carefully studied.

- Not all solvents form nitrosamines in the same quantities or in the same manner. Several studies indicate that the solvent piperazine forms nitrosamines directly, whereas the solvent studied by CATF – MEA does not form nitrosamines directly.
- It is difficult to measure even the total mass of all nitrosamines in plant exhaust stacks using normal techniques like infrared optical meters, forcing testing to be done by hand sampling, later analyzed in offsite laboratories. Even the hand sampling methods do not yield satisfactory results, leading regulators to assume – for the sake of conservatism – that nitrosamines are being emitted at the minimum detection level of the equipment.
- There is virtually no good detail on the speciation of nitrosamines within the total (i.e., the percentages of all the different varieties of nitrosamines). The lack of detail is problematic because different species of nitrosamines are vastly different in human toxicity.
- Opinions on safe emissions levels vary rather widely (i.e., a few orders of magnitude), with the Scottish Environment Protection Agency reporting, "A number of health guideline values have been suggested globally for nitrosamines in the ambient air ranging from 0.07ng/m^3 to 10ng/m^3."[240]

A call to action: future work on amine system nitrosamine emissions

The combined impact of these uncertainties makes it difficult for environmental regulators to make indisputable findings about the limits of nitrosamine emissions from carbon capture units that will adequately protect public health. Still, as described below, the current partial evidence does not justify slowing down CCS deployment. Cancer risks do not appear to change materially due to nitrosamine emissions, while CAP-related mortality and morbidity (as described above) reductions due to CCS deployment are notable.

The inability to measure total nitrosamine mass in the field leads to study results apparently showing nitrosamine "emissions levels" when the studies are instead stating the level (measured in single parts per billion) at which nitrosamines became undetectable by the test equipment available. Air modelers then simply take this worst-case figure at the vent stack opening and forecast dispersion and ground-level human exposures. Simply stated, the actual emissions could be two parts per billion, but if the equipment cannot register below 10 parts per billion, that higher 10ppb detection threshold is used as a surrogate emissions statistic.

The lack of speciation data (i.e., which exact members of the nitrosamine family are being detected) means that environmental regulators gravitate towards a worst-case assumption, that 100% of detected nitrosamine mass represents NDMA, the most carcinogenic species of nitrosamine. EPA estimates acceptable inhalation risk (1:100,000 risk of cancer) for NDMA (N-Nitrosodimethylamine; CASRN 62-75-9) at 7 x 10^{-4} micrograms per m^3 (0.7 nanograms per m^3) of ambient air.[241]

No one argues with protecting public health by making this 100% NDMA assumption, but strong indications suggest this assumption may be markedly incorrect. The only study the authors found with nitrosamine speciation data, including NDMA specification, showed NDMA comprising between 1/100th and 1/150th of the total nitrosamine emissions, not 100%.[242]

Moreover, even when these worst-case assumptions are compounded, air modelers still do not see grave concerns. To get a sense of the magnitude of the nitrosamine issue, CATF's air modeling consultant performed a desktop air pollution dispersion modeling exercise that assumed nitrosamines from breakdown of certain proprietary solvents are emitted at rates equal to nitrosamine non-detectability levels of conventional air monitoring equipment. CATF's consultant then followed the NIPH assumption of assuming 100% NDMA composition of the nitrosamine mass. Having made worst case assumptions both as to mass emitted and speciation, the consultant ultimately concluded:[243]

> *It is important to note that the HAP modeling by HEM4 indicates that cancer and noncancer risk is low at both base and control cases for the cement plant and refineries – that is, before and after the introduction of the CCS at these facilities. The cancer risks are on the order of 1-in-10 million, which is an order of magnitude below EPA's typical "ample margin of safety" of 1-in-1 million used by the Agency to protect public health for the population surrounding HAP sources, and several orders of magnitude below EPA's upper-end of the acceptable risk range, which is an MIR [maximum incremental reactivity] of 1-in-10 thousand (or 100-in-1 million) that the Agency attempts to limit to any person from HAP sources (EPA, 1999).*

It is important to clarify that the risk assessment discussed in the above-cited paragraph is cancer death risk to an individual over a lifetime of exposure to the nitrosamine emissions adjacent to the carbon capture installation. In contrast, the CAP health benefits (i.e., the 38-85 lives saved) are measured annually.

The U.S. government should sponsor research on this topic to determine whether the potential risks from these chemicals are sufficient to raise concerns about the viability of CCS as a significant tool for abating GHG emissions.

Carbon Capture Objection #2: Possible perpetuation of fossil facilities at which carbon capture equipment is retrofitted

The environmental justice (EJ) movement and the environmental non-governmental organization community do not speak with a single voice on this issue. A review of many written statements and observations at relevant meetings reveals two claims supporting Objection #2:

- First is the local "perpetuation" issue, i.e., the fenceline community and its relationship with the emitter facility. Carbon capture skeptics maintain that even if the CC project (which may affect only certain stacks inside a broader emitter facility site) abates some CAPs and emits only immaterial amounts of HAPs or carcinogens, this is insufficient. Only complete closure of the *entire facility* will stop all CAP and HAP emissions from the entire facility; adding CC to a portion of the emitter facility will keep the entire facility open when it would otherwise be scrapped.
- Second is the global question of perpetuating fossil fuel consumption. Skeptics of CC argue that if a facility uses fossil fuels, the entire facility is the issue: abating even a substantial portion of GHGs using CC is a poor substitute for complete closure and abandonment of the facility. Further, if the entire plant were to close, global use of fossil fuels would marginally decrease. While there may be an argument for climate change mitigation by accelerating the closure of major industrial facilities, it is not a fenceline community issue *per se* since CO_2 is not directly deleterious to local health.

These claims must be evaluated at a plant level: parsing the 2nd objection by plant type in various industries

A main current running through this entire paper is that carbon capture is not an industry but is, instead, a family of pollution control technologies that can economically be applied to control some GHG emissions in some industries. The difficulty or ease of doing so depends on the operating environment in each such application.

As such, speaking in generalities about carbon capture retrofit projects perpetuating either CAP/HAP-emitting plants or plants that emit GHGs from fossil fuel combustion may not be a helpful approach. At the very least, the discussion should center on the *types* of plants in specific industries that may add carbon capture to specific equipment. Carbon capture, for example, should be examined when it is applied "to the stoves that combust blast furnace gas in integrated primary steel mills"[rrrr] as opposed to the "steel industry."

Pulp & Paper and Cement: Fossil fuels are not perpetuated if the plant in question is not a fossil fuel plant. Two large sources of U.S. CO_2 emissions, the pulp & paper industry and the cement/lime industry, generate most of their GHG emissions through non-fossil fuel processes.

Approximately 70% of pulp and paper's 140 million metric tons/year of CO_2 is generated by burning wood waste products (i.e., a biofuel), and approximately 55-60% of the U.S. cement & lime industry's 82 million metric tons/year is generated by roasting limestone ($CaCO_3$) in a lime kiln to produce lime product (CaO) with CO_2 being released.[ssss]

These industries comprise about 20% of U.S. stationary industrial CO_2 emissions (including biogenic CO_2). Both are highly competitive commodity industries that, given the high cost of transportation of the feedstock, tend to be regionally based to be near raw materials and to customers, because of the high cost of transporting finished end products, paper products, and cement. Low-cost plants with good local markets will stay open, with or without CCS. High-cost plants in challenging local markets are likely to close, with or without CCS.[tttt]

Integrated primary steel mills with blast furnaces: A different issue is raised by the steel industry's primary iron-producing operations (as distinguished from steel "mini-mills"

[rrrr] Blast furnace gas is a low heating value waste stream from the blast furnace process that is approximately 20% composed of carbon monoxide. Carbon monoxide is created because atmospheric oxygen flow for combustion of coke is restricted in a blast furnace to promote reduction (liberation of oxygen) of iron ore.

[ssss] The 70% figure was derived by dividing U.S. pulp & paper industry biogenic emissions by the sum of both non-biogenic and biogenic emissions, using most recent U.S. EPA GHGRP FLIGHT data. The 55-60% depends on the carbon intensity of fossil fuels used for heat and is commonly cited in the literature. One reference is https://www.norcem.no/en/Cement_and_CCS.

[tttt] In the case of pulp mills, another possibility is shutting down old, small paper machines that make commodity products (newsprint and uncoated free sheets) and adding new, larger paper machines that make high value products (specialty packaging or branded tissue products).

that use recycled steel as feedstock). The best carbon capture opportunities in these old-line steel mills are for the large furnaces/stoves that combust the carbon monoxide-laden waste gases that are a byproduct of partial oxidation of coke (refined metallurgical coal) used to strip oxygen molecules from raw iron ore in the blast furnace. The eight integrated blast-furnace-based mills and associated coke batteries that together generate ~45-50 million metric tons/year of U.S. CO_2 emissions have been making steel at their present sites for an average of 117 years.[uuuu] It seems improbable that voluntarily adding GHG emissions controls to one set of vent stacks at one of these giant facilities will be a dispositive factor for whether the mill is abandoned or continues to operate.

Oil Refining: The oil refining industry is perhaps the most frequent target of CCS critics, who maintain that investment should not be made in reducing emissions from an industry that will ultimately be replaced by vehicle electrification. Large U.S. refineries (emitting one million metric tons of CO_2 per year or more) have been around for a long time, dating from the year 1929 on average.[vvvv] These facilities have, of course, been upgraded over time; most have, however, been making the same basic products in the same locations for almost a century.

U.S. refinery capacity has been in the 16-18 million barrels/day range since 1999 (**Figure 8**). Refinery margins (**Figure 9**) are poor during recessions (2009-2011 and 2020) and are profitable in the $8-13/bbl range otherwise. In other words, U.S. climate policies have not, in general, reduced refinery profits. If refiners are willing to add CCS to portions of their operations and need to amortize the investment over the 12-year life of 45Q subsidy payments, doing so is unlikely to determine the fate of the refinery one way or another.[wwww] Rather, it seems more likely that the CC equipment will, at a minimum, mitigate a modest portion of the environmental damage done by oil refining, absent stronger federal government action to, for example, ban internal combustion light duty vehicles.[xxxx]

[uuuu] EFI arrived at this figure by researching the individual history of the eight integrated still mills listed in EPA's FLIGHT system.

[vvvv] EFI ranked the refineries listed in EPA's flight system. Having identified the > 1 million MT CO2 emitters we researched the history of the individual refineries to find the start of refining operations.

[wwww] In some refineries, gasoline refining is giving way to manufacture of biodiesel from imported plant oils. Some GHG-emitting process units are less needed (such as FCCUs), and others must be expanded (steam methane reformers). But liquid transportation fuels continue to be produced at the same site. Fenceline community members who want no refinery at all continue to be frustrated.

[xxxx] Such bans on internal combustion engines may take hold in a significant number of states, notably California, with its recent Air Resources Board approval of a first-in-nation ZEV regulation, effectively banning sales of new ICE light duty vehicles in the state by 2035. https://ww2.arb.ca.gov/news/california-moves-accelerate-100-new-zero-emission-vehicle-sales-2035

Figure 8
US Operable Refinery Capacity Last Two Decades[244]

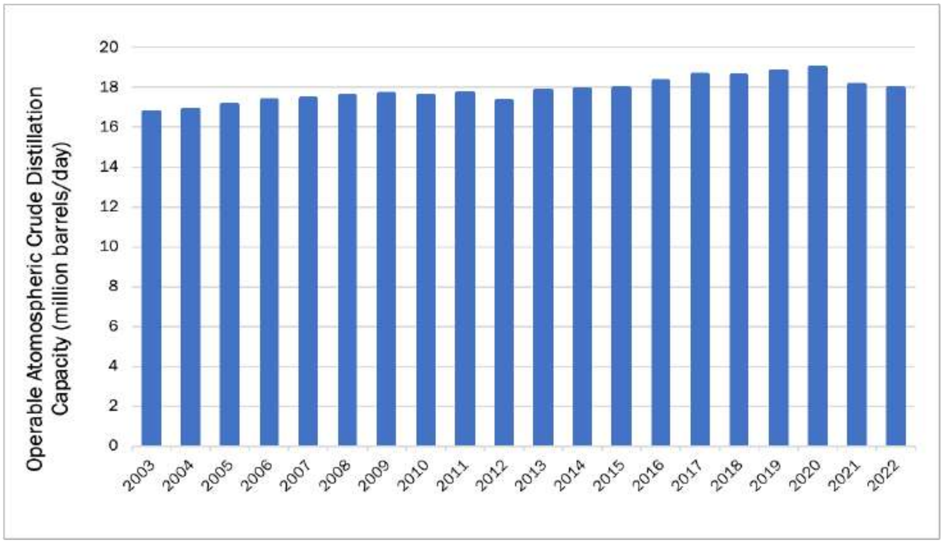
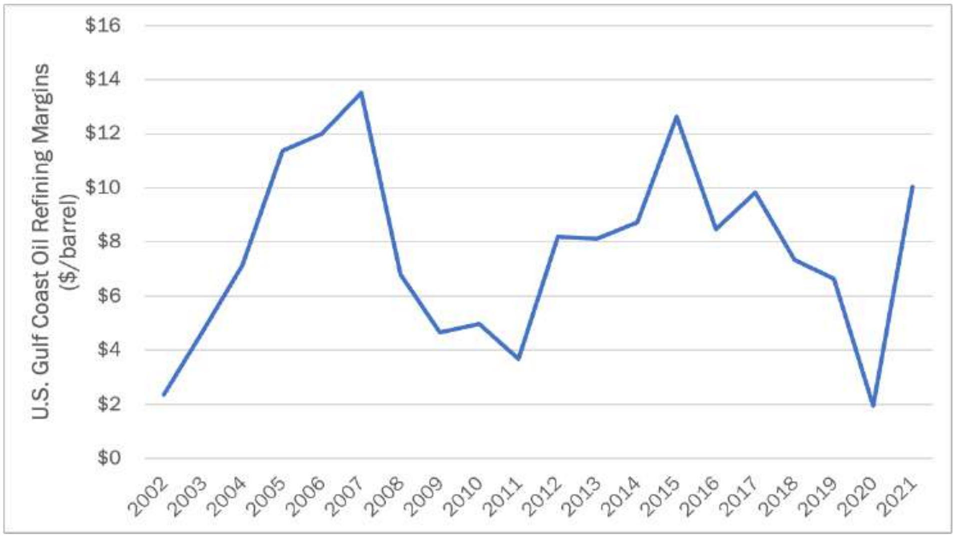


Figure 9
Gulf Coast Refining Margins, 1999-2021[245]



Coal-fired power plants: For various reasons, coal-fired power plants have been exiting the industry at a rapid pace. Drivers of coal's reduced role in the market include relatively inexpensive and abundant natural gas, increased renewable generation, state climate policies, and for older plants, the expense of environmental compliance, their small scale, and poor efficiency.

Older coal plants that are fated for closure for non-GHG related reasons are unlikely to be candidates for CCS. On the other hand, newer, more efficient coal plants will likely survive for as many as two decades, with or without CCS. An example: the 1600 MW, 2012 vintage, $5 billion Prairie State Energy Campus, owned by a group of municipal and cooperative utilities. Adding CCS to this plant, given today's incentives and costs, is likely to be a break-even proposition but not a lucrative source of additional profitability. This makes it difficult to argue that adding CCS would prolong the plant's life. It does seem more likely that CCS would simply reduce GHG emissions during the period that the plant is operational.

The bottom line on perpetuation claims

Discussion of environmental justice is incomplete without examining the perpetuation hypothesis, which undercuts public, political, and financial community interest in applying CCS to meet U.S. climate goals. As described above, these claims must be carefully evaluated on a plant-specific basis.

Policy recommendations

In its guidance published in February 2022, the White House Council on Environmental Quality recommended that federal agencies, including EPA and DOE, collaborate on studies regarding the effect of CCS on air quality in the U.S., including evaluating the "use of air dispersion modeling as part of comprehensive air quality impacts analysis."[246] CEQ also asserted that the studies will be used to "develop additional guidance for considering air quality impacts as part of the planning and permitting process for CCUS activities."[247] In addition, DOE requires the recipients of its funds to report data on non-CO_2 air emissions associated with CCS.

Building on these efforts, the EPA and DOE should investigate the comprehensive environmental costs and benefits of CCS deployment, focusing on retrofits in various industries and sites (Recommendation 5A). The results should be incorporated into federal policies, including NEPA proceedings (Recommendation 5B). DOE should encourage the beneficiaries of federal cost-sharing grant agreements to follow best practices in community disclosure of comprehensive environmental costs and benefits of CCS (Recommendation 5C).

Recommendation 5A. State environmental quality authorities should require carbon capture project proponents to perform and comprehensively disclose an analysis of the combined impact on emissions of CO2, criteria air pollutants (CAP), and hazardous air pollutants (HAP) of the host facility and the new capture plant.

This would be a *community disclosure requirement*, not a change in the actual Clean Air Act-based permitting regime that EPA generally has delegated to individual state air quality authorities.

Recommendation 5B. DOE should fund and undertake research examining the net changes of CAP and HAP that result from carbon capture installation applied in industries characterized by host facilities that produce both high quantities of CO2 and conventional pollutants.

These analyses should focus strongly on retrofits in various industries and pre-existing pollution control systems and should be integrated into state-of-the-art air modeling and epidemiology.

Recommendation 5C. The findings of the studies from Recommendation 5B should be incorporated into federal policy development, including NEPA proceedings.

Based on the findings of the recommended analyses, EPA and DOE should develop guidance for federal agencies on measuring and disclosing the environmental cost and benefits of CCS deployment. The guidance should be used for all federal CCS programs, focused on CCS permitting and stakeholder engagement. It is not necessary to change Clean Air Act permitting regulations, including for major modifications of emitters; it would, however, be very valuable to include comprehensive, multi-pollutant analyses of CCS in NEPA proceedings, i.e., for Environmental Assessments, Environmental Impact Statement).

Recommendation 5D. DOE should encourage project owners who are the beneficiaries of federal cost-sharing grant agreements to engage in best practices in community disclosure of comprehensively considered environmental costs and benefits of carbon capture projects.

Even if, for air permitting purposes, a project may not be required to calculate net changes in sulfur dioxide, ammonia, CO_2, or aldehyde emission, fenceline communities are entitled to a fair, comprehensive, and transparent assessment of the environmental and economic costs and benefits of the project.

THEME 6: HARNESS COMMUNITY BENEFITS GIVEN THE ENERGY TRANSITION

Support ongoing engagement and partnership between developers and affected communities, including efforts to support workers affected by the energy transition

Overview

CCS projects may create an array of local social, economic, and environmental impacts; tradeoffs, benefits, costs, and preferences of the affected communities must be considered. As with all industrial installation deliberations, host communities are interested in a just decision-making process, where the community has adequate representation, knowledge of options and tradeoffs, and agency to influence outcomes.

Though CCS may impact local environments, in both positive and adverse ways, the potential for economic development through construction and permanent jobs created across the carbon management value chain should also be considered. Many disadvantaged communities have been burdened with pollution from nearby fossil fuel infrastructure and facilities; at the same time, these installations have been the main source of employment and tax revenue for the communities. These communities need to maintain or rebuild their local economies as they lower their environmental risks and transition to a clean energy future. Energy communities, especially those with local experience with oil and gas extraction and processing practices, may benefit from redeploying applicable skills to a rapidly growing CCS industry.

Building on the recommendation for better disclosure of the environmental impacts of CCS to communities in Theme 5, this chapter makes recommendations on how to fully recognize the environmental, social, and economic development dimensions of CCS from the community perspective. Full disclosure of the information should be paired with proactive community engagements and the creation of economic and social benefits for impacted communities.

Link to investability

Most capital providers consider environmental justice as they evaluate investments in energy transition infrastructure. Investors are increasingly screening projects for environmental and economic justice attributes as part of their due diligence process. These capital providers may be more motivated to participate in a project where good community engagement practices can be demonstrated and where local economic development can be broadly quantified and attributed to an investment. Moreover, the total project cost may be lower if a developer proactively identifies a community's priorities and addresses their concerns in the early phases of a project, thereby preventing delays or modifications required to address public concerns about the project.

Communities that may host CCS projects care most about the social and non-climate environmental impacts

CCS projects may induce various social and environmental impacts, including those related to health, safety, air and water quality, land use, and ecological integrity. Except for the global climate impacts of reducing GHG emissions and the national/regional economic value of the facility or facilities in question, these impacts tend to be highly localized.

Previous studies have found that communities have greater concerns about these local social and environmental factors than the technological factors related to hosting a CCS project. Focus group interviews conducted with communities in New Mexico, Texas, Ohio, and California on CCS as part of the DOE's Regional Carbon Sequestration Partnerships (RCSP) identified social factors, including previous experience with governments, the existing socioeconomic conditions, the desire for compensation, and perceived benefits to the community, as more significant concerns than the CCS technology itself.[248]

A study of two communities for pilot project sites for California's DOE-funded West Coast Regional Partnership found that communities wanted DOE to define the risks to be mitigated and to ensure that just procedures were followed for potential CCS projects.[249] In another example, a recent survey by the Livermore Lab Foundation in two communities in California suggested the most important components in building support for CCS projects in those communities included detailed public engagement, creation of new permanent jobs, and protection of land, water, and wildlife.[250]

Indeed, public opinions are formed by perceived risks and benefits (well-founded or otherwise) and are influenced by such factors as project alignment with the community's long-term goals, the degree of trust in the project team and government agencies, and the perceived equity in the process of project development.[251] DOE's experience from the RCSPs underscored the importance of proactive community engagement, including listening to individuals, sharing information, and addressing concerns, as integral components of project management for geologic storage projects.[252]

The case of a pilot carbon sequestration project by the Big Sky Carbon Sequestration Partnership demonstrates the value of engaging communities early and the consequences of not doing so.[253] At the beginning of the project, the partnership did not prioritize community engagement since the volume of CO_2 to be injected was small, and the team was unfamiliar with the community. However, as the project proceeded, community groups started expressing their concerns, largely because they distrusted the developer that planned to build a coal power plant in the pilot test location. As opposition grew, the project team moved the location of the project. After implementing a concerted public outreach, including multiple interviews, discussions, tours, and media strategy, the project successfully mitigated public opposition to the modified pilot project. This case, among other issues, highlights that low technological risk does not necessarily translate into a lack of public opposition because public opinions are formed by multiple social, environmental, and economic factors.

To summarize, while transparent disclosure of the environmental impacts of CCS deployment, as recommended in the previous chapter, is a valuable starting point for addressing community concerns, more must be done. Gaining public acceptance requires timely and genuine consultation, discussion, and negotiations with various local stakeholders.

CCS may offer an opportunity for a just transition in communities that rely on or are impacted by energy production or energy-intensive industries

As energy communities navigate the energy transition, CCS may enable some communities with a high proportion of energy production or energy-extractive industries to sustain their jobs as the economy moves towards the nation's net-zero target. CCS creates new jobs across various industries, including raw materials, engineering and design, construction, and operation and maintenance. Indeed, up to 1.8 million jobs will be needed for two gigatons per annum of CCS deployment by 2050 (**Table 17**) according to estimates from the National Energy Technology Laboratory (NETL).[254] CCS provides permanent positions in engineering and design, such as designing carbon capture facilities, pipelines, and injection sites, and operations and maintenance of carbon capture, storage facilities, and pipelines. As in the buildout of any new infrastructure, additional, non-permanent construction jobs will be created but will require thousands of additional workers during peak construction periods.[255]

Table 17

Estimated employment for CCS deployment[256]

	2030	2035	2040	2045	2050	Total
Number of project and infrastructure employees	4,704-35,000	74,726-556,000	62,495-465,000	57,926-431,000	36,422-271,000	236,273-1,758,000
Number of operations employees	700-3,105	11,120-49,330	9,300-41,256	8,620-38,240	5,420-24,044	35,160-155,975

A study in the United Kingdom identified that existing workforces in other industries could be transferred to fill CCS jobs; given the rising demand, newly trained workers will also be needed. More than half of the jobs would be craft positions and could be filled through apprenticeships **(Table 18)** – a key requirement to obtaining the full value of IRA tax credits in the U.S. Other positions would require standard degrees in engineering, or standard degrees in fields like engineering and geology *plus* post-graduate training, such as a one-year master's program.

Table 18

Skill requirements for CCS[257]

Discipline	Additional training requirement	Share of the number of jobs in 2020
Crafts	Modern apprenticeships	54%
Mechanical engineering	Degree plus post grad training	24%
Civil engineering	Degree	8%
Process engineering	Degree plus post grad training	4%
Offshore engineering	Degree plus post grad training	4%
Geology	Degree plus post grad training	3%
Electrical engineering	Degree plus post grad training	2%

Concerted efforts will be needed to ensure a ready workforce for CCS deployment at scale – and carbon management in general – given the heightened labor demand associated with the IRA

Transitioning an existing workforce to large-scale carbon management (which encompasses CCS and carbon dioxide removal) and training a new workforce will require government support and coordination, both to ensure a ready supply of qualified workers and ease the transition for those affected. This transition will be influenced by many economic, social, climate, and environmental changes, and intersect with the transitions in other industries. For example, the IRA is expected to add almost 1.5 million jobs by 2030, including 0.6 million construction jobs in the United States.[258,259] This estimate contrasts with a Bureau of Labor Statistics study performed pre-IRA, which projected construction jobs growth by 2030 of only 0.1 million.[260] For the next 10 years, construction workers will be needed in multiple sectors and industries beyond CCS, including solar, wind, EV infrastructure, and hydrogen.

Many federal and states have ongoing efforts to support the workforce transition. The BIL offers new opportunities for workforce development; its infrastructure funds can be used, in part, for workforce development as well as for direct grants for workforce training. For example, several transportation funds, such as $5 billion in Consolidated Rail Infrastructure and Safety Improvement Grants and $2.3 billion in Port Infrastructure Development Program Grants, allow the use of funds for workforce development and training projects.[261] To align with provisions in the BIL, federal agencies have initiated programs to promote the creation of good and equitable jobs or align the goals of the workforce transition with other programs. For example, recently announced FOAs of DOE on CCS projects require the applicants to submit a plan to “attract, train, and retain a skilled and well-qualified workforce.”[262,263,264] In these FOAs, DOE showed strong support for investments that “expand high-quality, good-paying, union jobs, improve job quality through the adoption of strong labor standards, and support for responsible employers.”[265]

Policy recommendations

CCS is one of many solutions required for the U.S. to achieve its decarbonization objectives. Its viability as a decarbonization solution will be partially tied to addressing environmental and social justice concerns regarding the impact of proposed projects. Community engagement and workforce development are critical efforts to help fit CCS within the portfolio of decarbonization solutions and increase the interest of investors who screen for non-monetary benefits resulting from project development.

In this context, there have been growing federal efforts for community-informed CCS deployment with economic benefits to communities. Recently released FOAs on CCS demonstrations by DOE require the applicants to submit a detailed community benefits plan, including an analysis of community and labor stakeholders, along with assessments of workforce and jobs created, project benefits and negative impacts, and how they flow.

Building upon these efforts, federal agencies should initiate community-based, collaborative research of the economic, social, and environmental impacts of CCS to communities to develop engagement guidance for federal agencies (Recommendation 6A). The appropriation of benefits afforded to a developer and the community can be formalized within a community benefits agreement (CBA); there should be public support for local capacity building of communities to lead negotiations of CBAs with CCS developers (Recommendation 6B).

Recommendation 6A. Federal agencies should initiate community-based, collaborative research and community engagement programs for CCS technologies and infrastructure, with the goal of developing engagement guidance for agencies.

CEQ recommended that federal agencies with substantial CCS technology development and deployment activities, including DOE, EPA, DOT, and the National Science Foundation, initiate interdisciplinary RD&D programs and robust community engagement for CCS technology to be "informed by diverse academic perspectives and aligned with community objectives and goals."[266]

Consistent with this recommendation, the future collaborative research of federal agencies should include comprehensive and interdisciplinary research on the economic, social, and environmental impacts of CCS on communities through direct engagement with potential CCS host communities. The research should develop policy guidance to minimize the risks and provide fair benefits to communities, ensure just procedures for project development and implementation, and align CCS with community goals and priorities. Based on the research findings, the federal agencies should develop community engagement guidance and share it with federal, state, and local agencies. The guidance should be used for all federal programs for CCS deployment, such as OCED's carbon capture demonstration program.

Research outputs could also benefit project developers and investors by providing information on potential environmental and social risks for CCS projects. For example, the research could produce a mapping tool of energy communities, perhaps adding layers to EPA's EJScreen, with economic and labor indicators, such as trade/training schools/organizations, current energy jobs, jobs not in energy whose skills align with various energy infrastructure, and unemployment rates by counties. This mapping tool would benefit all stakeholders in the energy transition, beyond just CCS stakeholders.

Recommendation 6B. DOE, working with states and local governments, should provide direct funding for the capacity building of communities to lead the negotiation of CBA with CCS developers.

How the labor force will grow and what specific benefits will accrue to the groups proximate to CCS development can be shaped by constructive negotiations between communities, their leaders, and CCS developers. Community engagement by developers offers the chance to design outcomes to accommodate preferences expressed by those who have a stake in the project. This approach where communities have agency and efficacy in the process, also benefits developers by gaining a social license to operate. The appropriation of benefits afforded to both parties – the developer and the community – can be formalized within a community benefits agreement (CBA), which, in turn, acts as an enduring basis for continual engagement across all phases of the project.

APPENDIX A: METHODOLOGY

The policy recommendations provided in this paper are a result of a multi-step research and analysis approach. As a first step, the authors performed a preliminary mapping of the six risk dimensions (see page 1) to the CCS value chain, namely capture, transportation and storage; see summary in Table A1. Where material risks for CCS were identified, specific, deep-dive analyses were required as a precursor to policy recommendation development. As a second step, analyses were conducted by commissioned whitepaper authors, each who are recognized experts in specific areas along the CCS value chain. Table A1 also indicates within which whitepaper the identified risk dimension is explored.[yyyy] Whitepaper titles, authors and affiliations are:

I. Addressing Cashflow Challenges for Commercial Carbon Capture Projects – Sasha Mackler, Bipartisan Policy Center
II. Developing a Robust Commercial Demonstration/Deployment Track Record for Geologic Sequestration – Sue Hovorka, University of Texas, Austin
III. Achieving Scaled US CCS Deployment: Challenges, Prospects and Recommendations – Mike Schwartz, Elysian Carbon Management
IV. Eliminating Non-Cashflow Risks of CCS to Full Scale-up of Geologic Storage once Commercial Deployment has been Achieved – Steven Carpenter, Carpenter Global LLC
V. The financing effects of addressing CCS technical and commercial scale-up barriers: Remaining challenges – Stephen Comello, Stanford Graduate School of Business & Jeffrey Brown, Stanford University

In the third step, preliminary drafts of the whitepapers were circulated to a curated group of peer technical and financial experts with experience along the value chain of CCS. The contents of the whitepapers were discussed within a Chatham House rule technical workshop to debate and refine the perspectives and to offer new lines of inquiry. New lines of inquiry were pursued, and additional detailed analysis was conducted by the authors in parallel to the whitepaper authorship. In the fourth a final step, policy

[yyyy] It is important to note that whitepapers express the views held by the given author, serving as baseline input to the policy recommendations contained within this report. However, the findings and recommendations provided in the whitepapers should not be interpreted as the views of EFI. The policy recommendations contained within this report may or may not align with those expressed within the whitepapers.

recommendations were developed because of the synthesis of primary and secondary desk research and economic modeling, industry (technical and financial) interviews and finalized (post technical workshop) whitepapers. The totality of the work was conducted between March – December 2022 inclusive.

Table A1
Mapping of investment risk dimensions to the CCS value chain

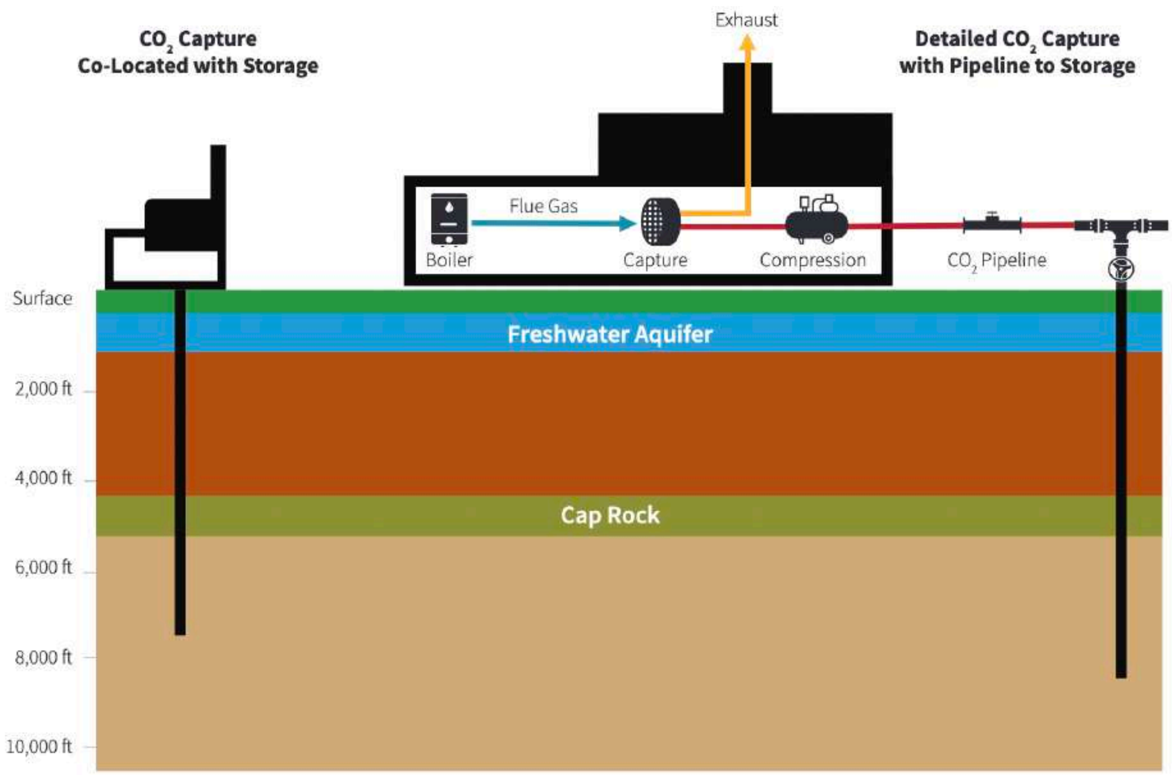
	CCS Value Chain (generic)		
Investment Risk Dimension	Carbon Capture	Pipeline Transportation	Geologic Sequestration
Commercialization risk: Lack of commercial deployment track record	Virtually no commercial deployment in heavy industry in U.S. for pollution control purposes and only one coal power plant.	Well proven.	One large commercial demonstration. Proven for incidental storage EOR. **(Hovorka)**
Revenue risk: Insufficient and/or volatile revenues	Total of $50/MT x 12-year life to cover all three components. Inadequate to cover costs for majority of industries (cement, refining, hydrogen, fertilizer, combined industrial heat & power plants). Exception being a few industries that already emit pure CO_2. **(Mackler)**		
Regulatory and policy risk: Binary risks that that are difficult to control, predict, or hedge	Interaction between air permits for existing plant and new equipment. **(Schwartz)**	No federal involvement in certifying need for interstate CO_2 pipelines, hence challenge obtaining easements. **(Carpenter)**	Uncertainties in conversion of old hydrocarbon wells for use in sequestration. Concerns about long-term liability from completed projects. **(Carpenter)**
Infrastructure risk: Presence/absence of upstream and downstream infrastructure	N.A.	Economic case is to build large enough pipelines to handle multiple projects.	Likely need to be big enough to have diversified customer base, and gain economies of scale in permitting, operations, and compliance.
Financial regulatory risk: Regulatory compliance, investment competitiveness and tax position	Projects structured as partnerships to manage tax credits, but many investors cannot easily belong to partnerships, and very few have federal income tax liability. **(Comello/Brown)**		
Reputation risk: Reputation, social license to operate and stakeholder acceptance uncertainty	Severe challenges environmental justice, release of criteria air pollutants, hazardous air pollutants and potential “perpetuation of fossil fuels.” **(Schwartz)**	Poor government promulgation of understandable data on public safety record of CO_2 pipelines. **(Carpenter)**	Lack of public acceptance of CO_2-EOR, in part because of assumed large increase in total US oil production. Lack of reassurance on seismic. **(Carpenter/Hovorka)**

APPENDIX B: OVERVIEW OF THE CCS VALUE CHAIN

The following overview of the CCS value chain was originally published in 2020 report published by EFI and Stanford University titled "An Action Plan for Carbon Capture and Storage in California: Opportunities, Challenges, and Solutions."[267] It has been adapted for inclusion in this study.

Figure B1

Simplified CCS Value Chain



There are two main permutations of CCS projects—those with on-site CO_2 storage and those that require CO_2 transportation from the emission source to the storage sink. *Source: Energy Futures Initiative and Stanford University, 2020.*

CCS involves CO_2 capture; compression and transport to the storage site; and subsurface injection via dedicated geologic storage or EOR. While there are many possible technology permutations of CCS, this study is largely focused on post-combustion amine absorption capture, with or without CO2 pipeline transport, and permanent geologic storage in saline reservoirs. **Figure B1** depicts the two major permutations of this process: CCS with and without CO2 transportation. CCS projects that are co-located directly above suitable CO_2 storage have the benefit of not requiring CO_2 transport.

CO_2 Capture

Carbon capture equipment is placed at or near the source of emissions, resulting in the separation of a highly purified stream of CO_2 from other waste gases across a range of industries, equipment, and processes. **Table B1** illustrates many of the emitters, equipment, and processes that CCS technologies must be designed to accommodate, as well as the complicated environment in which both project developers and regulators will need to operate.

Table B1

Examples of CO_2 Sources

EXAMPLES OF CO_2 SOURCES

Point Source of Emissions	Emitting Equipment	Emitting Processes
Power/electricity	Natural gas combustion turbine	CH_4 combustion
Petroleum refining	Fluidized catalytic cracking unit	Catalyst regeneration
Hydrogen production	Steam methane reformer	CH_4 reforming
Industrial cogeneration	Natural gas combustion turbine	CH_4 combustion
Cement production	Cement kiln	Limestone calcination & process combustion
Ethanol production	Fermentation tank	Fermentation
Fertilizer production	Steam methane reformer	CH_4 reforming
Biomass-derived H_2 production	Gas separation unit	Syngas hydrogen depletion

Carbon capture equipment can be utilized on a number of processes in multiple industries. *Source: Energy Futures Initiative and Stanford University, 2020.*

The capture of CO_2 can occur through three different methods: pre-combustion, post-combustion, and oxycombustion. Pre-combustion capture is a process in which ambient air is drawn into an air separator that removes nitrogen from the gaseous mixture and outputs near-pure oxygen. Fuel (e.g., natural gas) is then gasified (rather than being combusted) in the presence of oxygen to produce a synthesis gas (syngas) composed primarily of hydrogen and carbon monoxide. After a resultant chemical reaction, the carbon monoxide is converted to CO_2 and enters an air capture device along with the hydrogen. Whereas the hydrogen is not captured and is ultimately used to produce electricity, the CO_2 is captured and enters a compressor where it is compressed into a supercritical state so it can be transported via pipeline for the purposes of utilization (e.g., EOR) or dedicated geologic storage. This method of CO_2 capture may be a less likely candidate for CCS retrofit projects due to its technical complexity.[268,269]

Oxy-combustion capture involves a similar process to pre-combustion capture, except the fuel is combusted with oxygen rather than gasified, which yields a flue gas of mostly water vapor and highly concentrated CO_2.[270,271] During the initial oxygen separation stage, nitrogen is removed from the air and yields an oxygen purity of approximately 95 percent, which provides an environment that allows for CO_2 to be captured more easily after fuel combustion. Oxy-combustion capture has been considered a suitable technology for NGCC-CCS that could increase flexible operation in the electricity sector.[272,273,274] Despite its potential to simplify the CO_2 capture process, several challenges to oxy-combustion remain including operational, energy consumption, and capital costs.[275] A variety of chemical and physical processes can be used for post-combustion capture, depending on the composition of the gas stream from which it is captured.

Some sources such as CO_2 from ethanol production, ammonia manufacturing, or hydrogen production from SMR, require only dehydration and compression from carbon capture. Other sources, like power plants and cement manufacturing, have dilute concentrations of CO_2 (three to 30 percent) and require complex chemical separation processes. The most mature gas separation process is referred to as post-combustion capture using an absorption-based chemical scrubber that removes the CO_2 from the flue gas.[276]

Amine capture is the most mature post-combustion capture technology,[277] with higher efficiency and relatively lower costs than other capture technologies.[278] The process involves passing the captured gas stream through an amine solution, which selectively removes CO_2. Subsequent heating of the amine solution releases a concentrated stream of CO_2 that is captured then compressed into a supercritical state for transportation or storage.[279] Amine capture is easily scaled up and applied to large CO_2 point sources, such as power generation and hydrogen production, making it suitable "for the majority of industries that are anticipated to require CO_2 capture in the future."[280]

Two other less mature post-combustion carbon capture technologies are adsorption and membrane filtration. Adsorption technologies filter CO_2 from gas streams using materials that selectively adhere CO_2 to their surfaces. Membranes tend to be modular and cheap to produce, making them readily adaptable to several use cases. However, as membrane systems require relatively high pressures and concentrations of CO_2, they may not be suitable for deployment at large, dilute sources of emissions, such as power plants.[281]

Concerns have been raised that post-combustion capture retrofits may reduce the flexibility of NGCC plants to complement the intermittency of wind and solar generation. Recent analysis concludes, however, that “the integration of liquid-absorbent based post-combustion CO_2 capture has negligible impact on the power generation dynamics of the NGCC... [and] the decarbonization of an NGCC via post-combustion CO_2 capture does not appear to impose any limitation on the flexibility or operability of the underlying power plant in terms of power generation.”[282]

CO_2 Transport

CCS projects require transport of CO_2 from the capture facility to the storage site unless the emissions source is co-located (i.e., located directly above) with suitable CO_2 storage. Pipelines can efficiently move large amounts of CO_2 and most CCS projects in operation today rely on CO_2 pipelines for transport. CO_2 is compressed into its supercritical phase, which exhibits the properties of both a gas and a liquid. Compression of the supercritical fluid significantly reduces the transport volumes and enables efficient travel through pipes.[283]

The pipeline infrastructure needed to gather and transport CO_2 is significant and requires energy to maintain adequate pressures; new and specialized pipelines are needed as existing pipelines that transport other fluids are not designed to accommodate such high pressures. Also, dehydration processes may be required for CO_2 as it enters the pipeline to minimize or prevent pipeline corrosion.[284]

CO_2 Storage

Permanent geologic storage is a viable method to store captured CO_2 and prevent release of emissions into the atmosphere. Geological formations suitable for long-term CO_2 storage include saline reservoirs as well as depleted oil and gas fields.[285] When injected below a low-permeability geologic seal and away from faults, CO_2 can be permanently stored.[286]

CO_2 can also be injected into an active oil or gas field to maintain subsurface pressure and increase oil mobility as a form of enhanced oil recovery. Most large-scale CCS projects to date have been driven by opportunities for CO_2 use in EOR;[287] the focus of this study, however, is on opportunities for permanent geologic storage options.

Finally, it is also possible to retrieve some fraction of the stored CO_2 if it becomes a valuable commodity at some point in the future, for example to create carbon-neutral aviation fuels from CO_2 and renewably sourced hydrogen.

APPENDIX C: FOAK, NOAK AND COST SCENARIO INPUT PARAMETERS

Table C.1

Baseline capture-technology specific performance parameters and capital costs

Industry	Annual Emissions Captured (metric tons)	Capital Cost $USD (2018)	Annual O&M (% of Capital Cost)	Power MWh per Captured metric ton	Gas MMBtu per Captured metric ton	Trans. & Seq. ($/metric ton)
Gas Processing	600,000	$ 23,523,777	6.0%	0.097	0.00	$ 15.00
Ethanol	500,000	$ 24,468,162	7.0%	0.116	0.00	$ 15.00
Ammonia (flue gas)	400,000	$ 143,341,440	4.0%	0.300	0.00	$ 15.00
Hydrogen (SMR 90% capture)	1,000,000	$ 335,654,394	2.6%	0.145	1.15	$ 15.00
Ethylene	500,000	$ 175,523,400	10.0%	0.150	2.55	$ 15.00
Cement	1,000,000	$ 187,382,810	7.0%	0.165	2.55	$ 15.00
Pulverized Coal Power	3,200,000	$ 814,765,089	4.2%	0.165	2.55	$ 15.00
Black Liquor Boiler	1,500,000	$ 433,449,240	5.0%	0.165	2.55	$ 15.00
Fluidized Catalytic Cracker	1,000,000	$ 307,085,252	4.4%	0.144	2.55	$ 15.00
Blast Furnace - BOF (Steel)	1,600,000	$ 452,019,235	5.0%	0.165	2.55	$ 15.00
Natural Gas Power	1,600,000	$ 500,000,000	5.0%	0.166	0.00	$ 15.00

Table C.2

Global parameters used to determine FOAK, NOAK per application cost values, and high/low inflation and high/low retrofit cost scenarios for each of FOAK and NOAK

Parameter	Value
FOAK Contingency multiplier	1.2
FOAK/NOAK retrofit multiplier	1.15
FOAK capital recovery factor	11.0%
NOAK capital recovery factor	13.0%
FOAK/NOAK Low inflation multiplier	1.16
FOAK/NOAK High inflation multiplier	1.38
FOAK/NOAK Input electricity cost ($/MWh)	$65.00
FOAK/NOAK Input natural gas ($/MMBtu)	$4.50

LIST OF ACRONYMS

Acronyms and their definitions	
ACTL	Alberta Carbon Trunk Line
AMT	Alternative Minimum Tax
BBB	Build Back Better Act
BECCS	Bio-Energy Carbon Capture and Storage
BIL	Bipartisan Infrastructure Law
BSER	Best system of emissions reduction
CAMD	Clean Air Markets Division of the EPA
CAP	Criteria air pollutants
CATF	Clean Air Task Force
CC	Carbon Capture
CCC	Carbon Capture Coalition
CCPI	Clean Coal Power Initiative
CCS	Carbon Capture & Sequestration
CEQ	Council on Environmental Quality
CI	Carbon intensity
DAC	Direct Air Capture
DOI	Department of Interior
DOL	Department of Labor
EA	Environmental Assessment
EDX	Energy Data Exchange
EF^3	Energy Futures Financing Forum
eGRID	Emissions & Generation Resource Integrated Database
EIS	Environmental Impact Statement
EOR	Enhanced Oil Recovery
EPC	Engineering, procurement, and construction
ERISA	Employee Retirement Income Security Act
FAST-41	Fixing America's Surface Transportation

Acronyms and their definitions	
FCCU	Fluid Catalytic Cracking Units
FEED	Front-End Engineering Design study
FERC	Federal Energy Regulatory Commission
FLIGHT	Facility Level Information on Greenhouse gases Tool
FOA	Funding Opportunity Announcement
FOAK	First-of-a-Kind
FONSI	Finding of No Significant Impact
FPL	Florida Power and Light
GAO	US Government Accountability Office
GC	Guideline Concentrations
GHG	Greenhouse gases
GHGRP	Greenhouse Gas Reporting Program
GS	Geologic Storage
HAP	Hazardous material air pollutants
ICA	Interstate Commerce Act
IEA	International Energy Agency
IEAGHG	International Energy Agency Greenhouse Gas
IP	Intellectual Property
IRA	Inflation Reduction Act of 2022
IRS	Internal Revenue Agency
ITC	investment tax credits
JCT	Joint Committee on Tax
JOET	Joint Office for Energy and Transportation
LAER	Lowest Available Emissions Rate
LIHTC	Low-income housing tax credits
LPO	DOE Loan Programs Office
LSTK	Lump-sum-turnkey
NAAQS	EPA National Ambient Air Quality Standards
NEER	NextEra Energy Resources
NEI	National Emissions Inventory
NEMS	US EIA's national energy model
NEPA	National Environmental Policy Act
NGCC	Natural Gas Combined Cycle
NOAK	Nth-of-a-kind

Acronyms and their definitions	
NOI	Notice of Intent
NXOAK	Next-of-a-Kind
OCED	Office of Clean Energy
PAB	Private activity bonds
PCC	Post-combustion capture
PPA	Power purchase agreement
PTC	Production tax credits
RCRA	Resource Conservation and Recovery Act
RPS	State renewable portfolio standards
SCOTUS	U.S. Supreme Court
SER	Significant Emissions Rate
SMR	Steam methane reformer
SRHA	Stock-Raising Homestead Act
STB	Surface Transportation Board
STB	Surface Transportation Board
UIC	Underground Injection Control
USE IT	Utilizing Significant Emissions with Innovative Technologies
USEER	U.S. Energy and Employment Report
USGS	U.S. Geological Survey
VOC	Volatile organic compounds

GLOSSARY OF TERMS

Terms and Abbreviations	
Blocker Corporation	A blocker corporation is a type of C Corporation. Tax exempt investors and foreign investors often set up offshore feeder corporation known as a blocker corporation when they invest in private equity or hedge funds to avoid US trade or business income tax.
BECCS:	Bio-Energy Carbon Capture and Storage. Capturing and storing CO_2 emissions that are generated by combustion of wood, agricultural waste, etc.
CAPs:	Criteria Air Pollutants. Basically, conventional pollutants that are not Hazardous Air Pollutants (HAPs), with including sulfur oxides, nitrogen oxides (NO, N_2O, and NO_2), particulates (four variants), carbon monoxide, and Volatile Organic Compounds (VOC).
CCS:	Carbon Capture and Storage. Pollution control for CO_2 starting with carbon capture and ending with subsequent underground injection for either GS or CO_2-EOR.
CHP:	Combined Heat and Power. Industrial units that combust fuels both for the purpose of making electricity to be used by the plant and to manufacture process steam for heating units.
CO_2-EOR	EOR is Enhanced Oil Recovery, meaning injection of various substances to extract additional hydrocarbons after yields from “primary production” and/or “secondary production” (usually waterflooding) begin to fall. CO_2-EOR refers to use of CO_2 as the injectant. CO_2-EOR typically elicits an extra ~2 barrels of oil per MT of CO_2 injected. Some portion of the CO_2 often is extracted with produced hydrocarbons and is “recycled” or reinjected again in a circular process, supplemented with additional purchased CO_2. Eventually the CO_2 ceases to flow readily back to the surface and remains in the subsurface formation.[288]
CO_2E	CO_2 equivalent as reported by EPA. Top level industry and emitter figures under FLIGHT combine all greenhouse gas emissions from a facility reported under a specific subpart. To CO_2 tonnage is added emissions for each other GHG as multiplied times a conversion factor that is believed to represent the relative warming damage per ton of the non-CO_2 gas. Thus CH4 (methane) is multiplied times 25 and nitrous oxide (major emission in fertilizer plants) is multiplied times 100.

Terms and Abbreviations	
eGRID:	A comprehensive data base of U.S. power plants that combines both EPA and U.S. Department of Energy information. eGRID is useful in examining industrial CO_2 emissions because it is the only federal source that gives detailed operating and emissions information on power plants that are located inside the fenceline of industrial manufacturing facilities (as opposed to plants serving the general commercial power grid).[289]
EOR:	Enhanced oil recovery, meaning injection of various substances to extract additional hydrocarbons from an aging well. See CO_2-EOR.
FLIGHT:	Facility Level Green House gas Tool. US EPA main site for dissemination of data gathered pursuant to the GHGRP.[290]
FOAK:	1st-of-a-kind project commercially deploying a technology in an industry.
GHGRP:	Greenhouse Gas Reporting Program under 40 CFR Part 98[291],[292]
GS:	Geologic sequestration, also known as "passive sequestration", with both terms meaning CO_2 is not utilized in enhanced oil recovery operations.
ITC:	Investment Tax Credit. A tax credit based upon some stated percentage of the capital cost of qualifying types of equipment. To be distinguished from PTCs which are based on the annual production (of MWhs, CO_2 capture, etc.)
IEAGHG:	IEA's Greenhouse Gas "Implementing Agreement" among IEA member countries, which has sponsored and published several landmark reports on CCS.[293]
LPO:	US Department of Energy Loan Programs Office
NEI:	National Emissions Inventory. Conducted every three years to combine the best state and federal data on CAP
NOAK:	Nth-of-a-kind project commercially deploying a technology in an industry
NXOAK:	Next-of-a-kind
SMR:	Steam Methane Reformer. (Not to be confused with Small Modular Reactor, also SMR.) Process that cracks methane (CH_4) molecules, the principal component of "natural gas", with heat and water under pressure. Combining the reforming reaction and the later gas-water shift reaction (ignoring the fact that some methane is not fully converted): $CH_4+2H_2O+heat \rightarrow 4H_2+CO_2$, with that CO_2 referred to as "process CO_2". The "heat" is provided by burning fresh natural gas, plus any unreacted CH4 and CO from the reforming/shift, which creates "combustion CO_2." SMRs provide hydrogen to oil refineries, as well as being the first step in ammonia and methanol manufacturing. I.e., emissions from SMRs can be found in many different GHG "source categories"—not just in subpart P (hydrogen).[294]
PAB:	Tax-exempt Private Activity Bond under Section 142 of the Internal Revenue Code

Terms and Abbreviations	
Section 45Q:	Also shown as §45Q. See US Code at 26 USC §45Q "Credit for carbon oxide sequestration". For regulations see 26 CFR §1.45Q-1. Refers to a tax credit for CCS, currently at \$50/MT for GS and \$35/MT for CO_2-EOR. Note that injection must comply with EPA rules under the Underground Injection Control program promulgated under the Safe Drinking Water Act, falling under Class II well permitting for CO_2-EOR and Class VI for GS. To earn credit for either CO_2-EOR or GS the injection must be reported under GHGRP subpart RR, with a Monitoring Verification and Reporting regime either approved by EPA or meeting the specifications of International Standards Organization #27914:2017. [Note: The October 28, 2021, draft of the Build Back Better Act increases the credit, subject to certain conditions to \$60/MT for CO_2-EOR and \$85/MT for GS.][295]
Tax Credit:	A non-cash incentive from the federal government that can be utilized, in lieu of a cash payment by the taxpayer, to pay federal income tax liabilities. Assume a taxpayer, without considering any tax credits it earned in a given year, calculates that it would owe \$150 of federal corporate income tax. The \$150 is called the "pre-credit liability." If the taxpayer has earned \$100 of tax credits, such as a §45Q tax credit, then it would pay its tax obligations with a combination of \$50 cash plus the \$100 of tax credit. Note that a tax credit is different than a tax deduction. A tax deduction reduces the taxable net income against which the tax rate (i.e., 21% is multiplied). A tax credit of \$1 reduces taxes by \$1. A \$1 tax deduction reduces taxes by \$0.21. In practice, few carbon capture projects have enough pre-credit federal corporate income tax liability to fully utilize §45Q.

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