COLUMBIA | SIPA
Center on Global Energy Policy

CAPTURING INVESTMENT: POLICY DESIGN TO FINANCE CCUS PROJECTS IN THE US POWER SECTOR

BY S.J. FRIEDMANN, EMEKA R. OCHU, AND JEFFREY D. BROWN
APRIL 2020

ABOUT THE CENTER ON GLOBAL ENERGY POLICY

The Center on Global Energy Policy provides independent, balanced, data-driven analysis to help policymakers navigate the complex world of energy. We approach energy as an economic, security, and environmental concern. And we draw on the resources of a world-class institution, faculty with real-world experience, and a location in the world's finance and media capital.

Visit us at www.energypolicy.columbia.edu

@ColumbiaUenergy

ABOUT THE SCHOOL OF INTERNATIONAL AND PUBLIC AFFAIRS

SIPA's mission is to empower people to serve the global public interest. Our goal is to foster economic growth, sustainable development, social progress, and democratic governance by educating public policy professionals, producing policy-related research, and conveying the results to the world. Based in New York City, with a student body that is 50 percent international and educational partners in cities around the world, SIPA is the most global of public policy schools.

For more information, please visit www.sipa.columbia.edu

COLUMBIA | SIPA
Center on Global Energy Policy

CAPTURING INVESTMENT: POLICY DESIGN TO FINANCE CCUS PROJECTS IN THE US POWER SECTOR

BY S.J. FRIEDMANN, EMEKA R. OCHU, AND JEFFREY D. BROWN

APRIL 2020

Columbia University CGEP
1255 Amsterdam Ave.
New York, NY 10027
energypolicy.columbia.edu

@ColumbiaUenergy

ACKNOWLEDGMENTS

We are grateful to the support of CGEP members and philanthropic gifts that made this work possible. Deep thanks to the unnamed reviewers who greatly improved the quality of this manuscript with their insights and helpful comments.

This policy paper represents the research and views of the authors. It does not necessarily represent the views of the Center on Global Energy Policy. The paper may be subject to further revision.

This work was made possible by support from the Center on Global Energy Policy. More information is available at https://energypolicy.columbia.edu/about/partners.

ABOUT THE AUTHORS

Dr. Julio Friedmann[1] is a Senior Research Scholar at the Center on Global Energy Policy at Columbia University. He is one of the most widely known and authoritative experts in the US on carbon removal (CO_2 drawdown from the air and oceans), CO_2 conversion and use (carbon-to-value), and carbon capture and sequestration. Dr. Friedmann recently served as Principal Deputy Assistant Secretary for the Office of Fossil Energy at the Department of Energy, where he was responsible for DOE's R&D program in advanced fossil energy systems, carbon capture and storage (CCS), CO_2 utilization, and clean coal deployment. He has also held positions at Lawrence Livermore National Laboratory, including Senior Advisor for Energy Innovation and Chief Energy Technologist. He is also the CEO of Carbon Wrangler, LLC, is a Distinguished Associate at the Energy Futures Initiative, and serves as a Special Advisor to the Global CCS Institute. Dr. Friedmann received his bachelor of science and master of science degrees from the Massachusetts Institute of Technology, followed by a PhD in Geology at the University of Southern California.

Emeka Richard Ochu[2] is a Research Associate at the Center on Global Energy Policy at Columbia University. He supports CGEP's Carbon Management Research Initiative (CaMRI), focusing on financial and policy analyses for application of carbon capture, use, and storage (CCUS) to power and industrial facilities. Prior to joining CGEP, Ochu was an Energy Research Economist at the Central Bank of Nigeria, where he published research on the electricity and gas subsector of the economy and served on various national energy projects. Previously, he worked in consulting and banking as an Energy Finance and Investment Lead, analyzing energy investment opportunities and providing finance for viable renewable energy projects in energy poor communities in Sub-Saharan Africa. Ochu holds a master of public affairs from Columbia University's School of International and Public Affairs and a master of science in energy economics from the University of Aberdeen, United Kingdom, as well as a bachelor of science with honors in economics from Abia State University, Nigeria..

Jeffrey D. Brown[3] is a Principal at Brown Brothers Energy and Environment, LLC, which he co-founded in 2017. B2E2's main practice areas are the economics, policy, and finance of implementing carbon capture and avoiding deforestation. In early 2020 he joined as Director of Economic Analysis the University of Wyoming's Enhanced Oil Recovery Institute, a leader in implementing use and sequestration of CO_2 in the oil industry. After an early career in debt capital markets and energy finance on Wall Street, Brown refocused his work on technologies and policies to fight climate change. From 2015 to 2019, Brown was an energy researcher and graduate school instructor at Stanford University, co-instructing the course Clean Energy Project Development and Finance at Stanford Business School and Stanford Law School. Until 2016, he was SVP for Finance & Strategy at Seattle clean energy firm Summit Power, developing wind, solar, and carbon capture projects. Brown has an MBA from Harvard Business School and graduated magna cum laude in economics from Harvard College.

TABLE OF CONTENTS

EXECUTIVE SUMMARY

Carbon capture, use, and storage (CCUS) is a key pathway to rapidly and profoundly reduce greenhouse gas emissions from large point sources such as power plants in a cost-effective way. While other kinds of low-carbon power receive widespread policy support aligned with today's capital markets, CCUS projects lack sufficient policy support to obtain conventional financing. This suggests additional policies are needed to bring CCUS forward in commercial power market deployment.

The authors undertook an analysis to help predict which policy configurations would incentivize widespread deployment of CCUS in the US electric generation industry. We examined a set of options and applied them to representative existing US power plant types—supercritical pulverized coal and natural gas combined cycle—with two ownership/revenue structures: traditionally regulated, vertically integrated investor owned utilities (IOUs) and independent power producers (IPPs) selling to IOUs under regulator-approved contracts. We used conventional models typical of a project finance assessment and determined which policies would be effective at attracting financing.

The government broadly has two options to make an energy project more economically feasible: It can lower the owners' costs through capital incentives (such as an investment tax credit or accelerated depreciation) and provide revenue enhancements (such as production tax credits, contracts for differences, or guaranteed power contract requirements). We modeled the financial performance of policy designs on various power plants based on fuel, generation technology, and ownership type. The analysis yielded these key findings:

- **Effect of ownership structure:** While most techno-economic analyses provide engineering information about unit construction and operating costs associated with CO_2 capture for any given facility and technology, the *all-in full cost per ton of CO_2 captured* varies substantially as a function of capital cost, debt-equity ratio, and other financial factors. The nature of ownership and the associated financial structures greatly influenced the full costs associated with carbon capture. In turn, those financial factors affect the full cost of energy and capacity of generators fitted with carbon capture equipment.

- **45Q tax credit:** Recent amendments to the US tax code included amendments of the 45Q tax credit, which provides a nonrefundable, transferable tax credit to taxpayers that capture CO_2 and either store or use it. The value of the 45Q credit is statutorily expressed in \$/MT CO_2: the value per metric ton captured and injected in enhanced oil recovery (EOR) is \$35/MT when the credit rises to its full level. A per-metric-ton-based CO_2 capture incentive is less powerful for a gas plant than a coal plant because an unabated gas plant inherently produces far less CO_2 per megawatt-hour (MWh) than an unabated coal plant. Enhancements to the current 45Q tax credit are necessary to support financeable projects, ranging between values of \$60-\$110 for all-in total credit value.

- **Capital cost incentives:** Because coal plants emit more CO_2 per megawatt-hour than gas plants, CCUS retrofits on coal plants require more capital investment dollars up front: 90% capture requires approximately $1.8 million per megawatt for a coal plant and $800,000 per megawatt for a natural gas combined cycle plant. Perhaps unsurprisingly, capital incentives like bonus depreciation, master limited partnerships, and investment tax credits have a disproportionately large positive impact on coal plant CCUS investment compared to natural gas combined cycle plant CCUS investment. This was true for both investor owned utilities and independent power producers.
- **Revenue enhancement incentives:** Among the policy options assessed, revenue enhancement and guarantees like production tax credits or contracts for differences appear to have the best finance and deployment outcome. Such approaches also can be transactionally easier for investors, owners, and operators and could have simpler deal structures. They also provide clear public benefit in that payment is contingent upon performance of CO_2 emissions reduction through carbon capture and storage.

Recommendations

In considering policy design to decarbonize existing power plants, policy makers should take into account more than just the cost of CO_2 capture. They should consider ownership structure, fuel type, plant efficiency, and policy mechanisms to achieve the desired outcomes. Policy recommendations should differ for stimulating adoption of carbon capture for coal plants versus gas plants, for ensuring the lowest total system costs, or for realizing the fastest decarbonization potential.

Future project finance analyses should reflect the presence or absence of CO_2 storage or transportation infrastructure, the vintage and efficiency of specific plants, regional differences in power markets, rapid technology changes available for both new and retrofit plants, and applications outside power generation.

1.0 INTRODUCTION

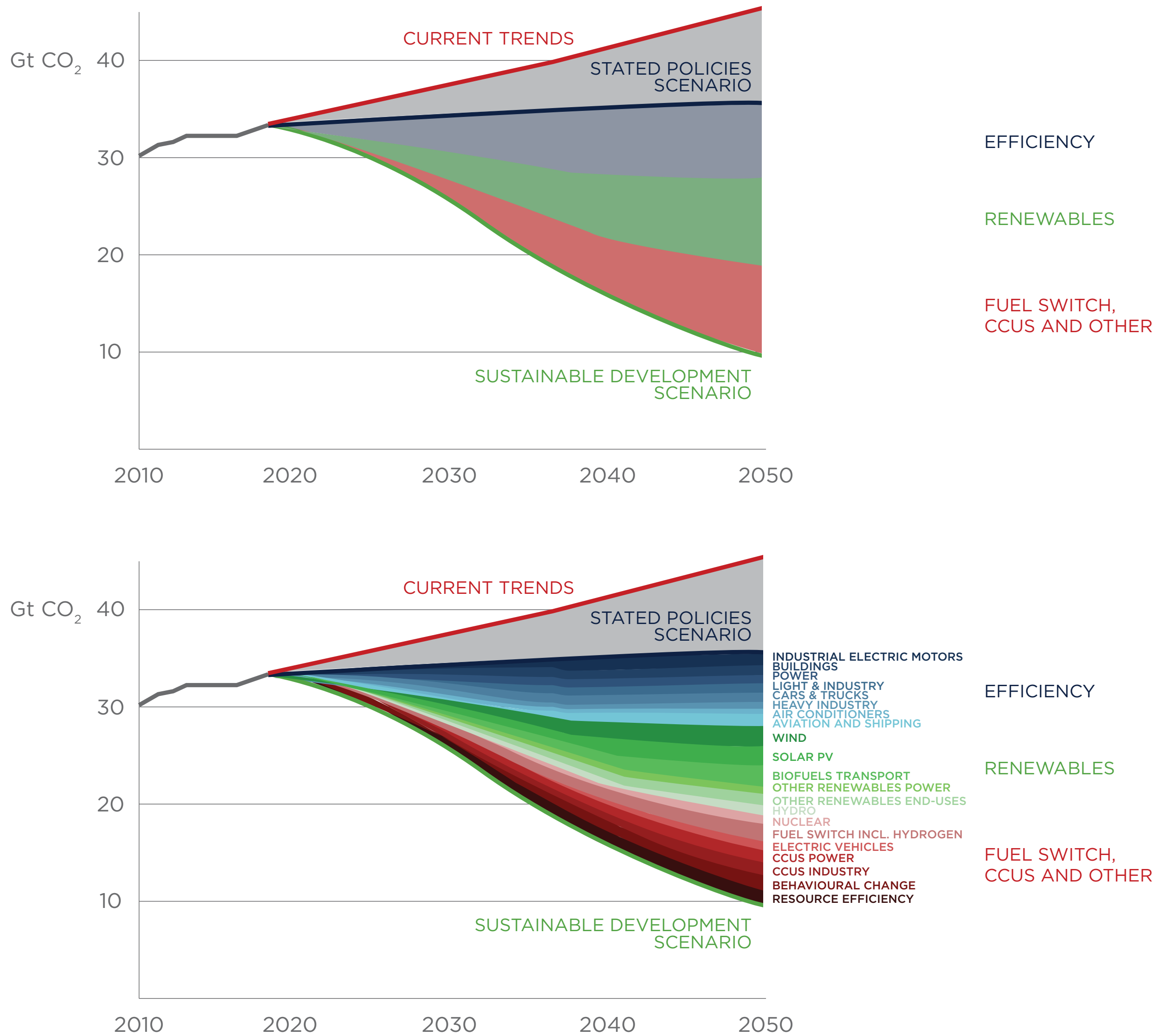
Deep, rapid reductions in CO_2 emissions have become a global imperative. This is driven by both the recent and startling results of scientific assessment of the impacts and consequences of climate change (IPCC 2019) and the recognition that the Paris Accords are both insufficient to task and not being met (IEA 2019; UNEP 2018). Efforts by global governments, environmentalists, youth movements, and financial institutions have created a sense of urgency shared by public and private leaders alike. Some of this is reflected in shareholder votes, divestment drives (IIASA 2018) and shifts in investment strategy (OECD 2017). It also appears that these efforts remain too slow to mitigate the worst impacts of human-made climate change.

One area of consensus among economists, activists, and governments is that power sector decarbonization is the highest imperative. In part, this is due to the power sector's global prominence as the highest emitting sector (EIA 2018). In part, this is due to the expectation that some emissions reductions in other sectors could be achieved through electrification using zero-carbon power, e.g., to substitute electric vehicles for gasoline or diesel engines or to electrify residential heat systems (Luderer et al. 2019). In part, this is due to the wide range of options available today, including end-use efficiency; substitution of renewables for coal and (locally) for gas; the remarkable technology improvements in renewable power systems including solar, wind, and battery technology; and other rapidly emerging facts (PIK 2019).

Growing consensus indicates that one of the critical strategies toward achieving a zero- or low-carbon economy target and deep decarbonization is encouraging private sector investments in carbon capture, utilization, and storage (CCUS) technology.[4] Achieving the goal of limiting warming to 2°C would require that power and industrial sector applications of CCUS would need to commit to a reduction of emissions by about seven gigatons per year by 2050, amounting to a global deployment of over 950 gigawatt (GW) of new and retrofitted power generation capacity with CCUS (IEA 2012). A recent Global CCS Institute report suggests that approximately 14 percent of cumulative emissions reductions will need to be met with CCUS to maintain average global temperatures below 2°C while reducing the cost of climate change mitigation (Global CCS Institute 2019). Additionally, deep decarbonization of some industrial sector emission sources would be practically impossible without CCUS.

This is a common analytical result: that CCUS is needed to achieve deep decarbonization at the lowest overall cost. The IPCC (2017), the IEA (2018), and many leading economic institutions (e.g., Jenkins et al. 2018; EFI 2019) find that CCUS remains important to manage cost and risk of power sector decarbonization (figure 1). This result is most important for new fossil power and industrial facilities, especially in developing countries, although this is true in OECD countries as well. Also, the more rapid a climate target is, the more important CCUS is in achieving that goal at lower cost (NPC 2019). As such, progress in CCUS in one sector will have applications and repercussions in other sectors as well, in part through creation of protocols and practices and through deployment-related cost reductions.

Figure 1: Energy-related CO_2 emissions and reductions by source in the IEA's sustainable development scenario (detail in second graphic)



Source: IEA WEO

To that end, one component of a strategy for decarbonization for the United States is application of CCUS on large point sources of emissions. In the US, approximately 28 percent and 22 percent of greenhouse gas (GHG) emissions come from power and industrial facilities, respectively (EIA 2018). A recent National Petroleum Council's report (NPC 2019) examined the central United States and estimated that up to 115 emitter sites, each having one or more units and emitting today a total of 477 million metric tons, would be suitable for CCUS retrofit based on their location, size, age, fuel efficiency, emissions of criteria pollutants, and competitive status in local power markets.

Much analysis reflects a focus on new generation as opposed to decarbonizing existing generation. Cost analysis is commonly framed in $/megawatt-hour as opposed to $/ton, with power sector climate goals framed outside a key climate metric. In part this is based on an expectation that new zero-carbon generation will displace existing plants and are a prerequisite for decarbonizing the grid. However, it is likely that some large fossil power emitters will stay in operation, in part because of the needs of regional grids, political forces, and the long remaining capital life of certain plants. Applying carbon capture to the most feasible individual generators would capture approximately 200 million MT per year (Brown 2019), and in many cases at lower system costs than other low-carbon options (Jenkins et al. 2018; NPC 2019).

For CCUS to be a viable pathway for decarbonization, investors and operators must create and invest in projects that yield financial returns at the levels demanded by lenders and investors. This has proven effective in the deployment of utility-scale solar and wind, and the replacement of coal by gas. Those project options benefited from a set of policies that provided long-term, firm market alignment through a series of incentives and mandates (e.g., RPS, ITC, PTC, and, in the case of new gas generation, regulator-imposed capacity adequacy standards). These incentives reduced the risks to investors. However, most of those policies exclude CCUS projects, leaving them to struggle to find investors; and the policies that do provide incentives and mandates are insufficient to overcome investor risks.

This study attempts to answer one important question: If investors and lenders wanted to put money into CCUS projects in the US power market, how do various capital and revenue incentives ensure that the financiers are repaid and earn appropriate returns? Said differently: ***What are the specific US policy design parameters that could provide investors and lenders with net cash flows that are both high enough and certain enough to attract private capital to CCUS projects?*** The goal is to provide clarity to potential policy makers regarding which specific policies would yield investment, how the policies compare in terms of costs and effectiveness, and for how long such policies should remain in place.

Existing Policies and Incentives

The recent legislative amendment of one US tax provision, the 45Q tax credit, provides an alternative policy tool in the absence of a carbon price. The 45Q is a nonrefundable, transferable tax credit that any CO_2 capture operator who stores or uses CO_2[5] (EFI 2018) could benefit from. For CO_2 captured and used for enhanced oil recovery (EOR) or natural gas recovery, the credit value is $35 per metric ton. For CO_2 captured and sequestered in saline geological formations, the value is $50 per metric ton. However, to qualify for this tax credit, power generation facilities and industrial facilities must capture an annual minimum of 500,000 and 100,000 metric tons of CO_2, respectively, and must begin construction by 2024 (IRS 2018). The 45Q credits are nonrefundable, which means either the capture project owners or (in case of transfer) the CO_2 injector/user must have substantial tax appetite to make full use of the credits, adding complexity to deals.

Passage of the 45Q tax credit expansion in 2018 created opportunities to expand deployment of CCUS in industrial, power, and other facilities. The estimated value of the 45Q credits is up to $50 billion over the lifetime of the credit, roughly 1/8 to 1/10 of the wind-production tax credit over the last 10 years (Global CCS Institute 2019). An estimate suggests that the revised 45Q credits could lead to about $1 billion in new investments by 2040 and add 10 to 30 million tons of additional CO_2 capture capacity, increasing total global capture by two-thirds (IEA 2018). However, considering the high cost of deploying CCUS technology, the highest cost being for carbon dioxide removal (CDR) applications such as direct air capture (DAC) (between $300-$600 per ton of CO_2), the size and duration of 45Q credits is insufficient to incentivize retrofits of many eligible power and industrial facilities. In short, additional incentives are needed to stimulate private investment in CCUS projects and to scale deployment.

Project Financing Gap

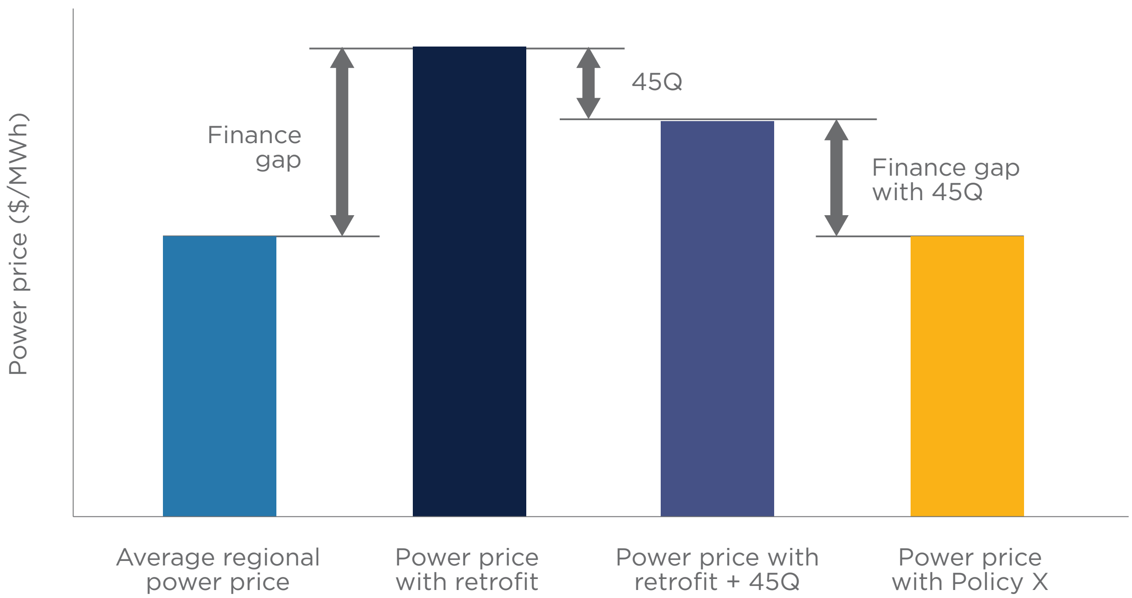
Project equity requires a return on investment, and return of invested capital is a serious challenge for most carbon capture projects. Lenders require interest and principal repayment, and equity requires a return on their investment, which can come in the form of current return and terminal value upon sale or another exit. Since the application of CCUS as a pollution control technique on power plants and industry is new, the equipment tends to be seen as an added cost, often quite expensive. That newness also adds perceived risk, which causes the financing rates charged by investors and lenders to be high.

The affirmative decision to proceed with a capital-intensive project is typically made only if financial analysis of the project shows adequate returns for its owners. More precisely, the sum of a project's revenues plus any recoverable tax benefits should be sufficient to cover: (i) all cash operating expenses and required capital repairs and replacements, (ii) interest repayments, (iii) federal tax liabilities (if any), and (iv) repayments to equity investors (including a risk-appropriate rate of return until repayment). Since equity is sometimes paid last, with operating expense, debt, and the US government taking first claim on cash, the ability to show adequate returns to equity is the litmus test of feasibility. NOTE: Different industries and technologies may require different rates of equity return. For example, the after-tax rate of return on equity on low-risk, simple projects might be in the single digits (e.g., 9 percent for a traditional regulated utility), while the appropriate rate might be 30 percent for a small upstream oil producer.

The capital-intensive nature of CCUS projects has proven a major inhibitor to investment, which has limited the rate of adoption and scale of deployment. The approximate cost of retrofitting a typical natural gas combined cycle power plant to include CCUS is roughly 46 percent of the combined cost of the generating plant and the CCUS equipment, i.e., hundreds of millions of dollars. This cost greatly affects the viability of projects, since the power price needed to cover capital and operating costs of the carbon-capture-enabled generator may be significantly above regional power prices.

Unfortunately, today's policies do not adequately support project financing. Although the 45Q tax credits create a viable value stream for many projects, the size of the credits is commonly not large enough to cover the project costs or clear the hurdle rate for investors. This creates a finance gap where potential investors lack confidence that their investment will be repaid along with the appropriate rate of return. Figure 2 shows average regional power prices at “X” per megawatt-hour in a competitive power market (first bar). If a power plant installs carbon capture and has no incentive, it would need to charge “Y” to cover all costs, debt, tax, and equity returns. With 45Q incentives, the power plant with carbon capture can cut its power price somewhat (with the 45Q incentive value replacing some cash revenue from electricity sales) and only needs to charge “Z.” Nonetheless a gap remains; without some additional incentive, the carbon capture project will founder. It can’t raise power prices in a competitive market: It will be undercut. It can’t charge a competitive power rate because equity investors will be shortchanged on their returns. NOTE: This is not unique to CCUS, and was true for wind and solar before portfolio standards mandated their electricity purchase.

Figure 2: Finance gap associated with a power plant CCUS project



Note: For any given project, higher power prices are needed to generate the revenues needed for profitability.
Source: Authors’ computation

Potential Financial Support Policies for CCUS

In this study, we assess a range of possible policies that could close the finance gap by providing additional revenues *or their equivalents* for potential power plant projects. The goal is to understand the form and magnitude of policies that could potentially close the finance gap and to compare them in terms of political or financial acceptability. This is to provide insight to policy makers and key stakeholders who are discussing additional incentives to help in deploying CCUS technology in industrial and power infrastructure. The policies we examine fall into two basic categories: capital incentives (which reduce the annual cost of repaying the original investment in building the carbon capture projects) and revenue incentives (which provide revenue enhancements over a portion of the project lifetime).

Capital Incentives

Most of the capital incentives analyzed are directly or indirectly based on tax benefits. Some of these reduce the federal taxes payable by owners of the projects, and others reduce the federal taxes paid by lenders to the projects. We chose these specific policy mechanisms in part because the United States has used such mechanisms in the past to help finance clean energy projects and because Congress is actively considering these capital incentives. Although direct cash grants for projects would also qualify as a capital incentive policy, we did not analyze grants as a policy measure.

Investment Tax Credit (ITC)

An ITC is a tax incentive that creates a dollar-for-dollar offset to the taxes owed by an owner of the project.[6] The size of the ITC incentive is typically a percentage of the original cost of certain elements of a project that are eligible property under tax rules. As an example, if a project costs $1.2 billion to build, of which $1 billion is ITC-eligible property, and with an ITC of 30 percent, $300 million of tax credits are created. A 10 percent owner of the project would get a $30 million tax credit that could be used to offset $30 million of federal taxes that would otherwise be payable during the tax year by the investor.

It should also be noted that when owners receive an ITC, the depreciable basis of the project is typically reduced dollar for dollar. So, in our example, the $1.2 billion project will have its depreciable basis reduced by $300 million—the amount of the ITC—down to $900 million.[7]

A typical example of this incentive is the Solar ITC, enacted in 2006 and extended in 2015, which enables residential and commercial (utility-scale) investors in eligible solar installations to claim a credit equal to 30 percent of the cost of eligible solar property (CCC 2019). For commercial and utility-scale installations to be eligible to claim ITC under the dictates of the 2015 amendments, construction must begin by December 31, 2021, and commence operation before December 31, 2023. The Solar ITC has proven to be a tremendous boost to the deployment of solar energy in the United States, although photovoltaic (PV) solar currently represents only about 2.5 percent of US electricity production (SEIA 2019).

Tax-Exempt Private Activity Bonds (PAB)

PABs are a form of "tax-exempt bond" that lowers the cost of capital for projects by providing debt financing at more favorable interest rates. Instead of being an incentive that impacts federal taxes of project owners, this incentive affects the federal taxes of the lender (i.e., the bond owner).

The term "tax exempt" means that an interest payment received by a bond owner is not generally includable in the federally taxable income of the bond owner.[8] Most tax-exempt bonds are issued by governmental entities for normal capital projects that are used by governments or the citizenry, such as roads, schools, or municipal-owned utility equipment.

Congress has allowed some specifically listed exceptions to this "governmental use" concept, usually created when the use of the capital equipment by a private party is considered to benefit the public. Bonds issued under these special exceptions are called tax-exempt private activity bonds, as opposed to tax-exempt governmental bonds. NOTE: The legal framework for PABs is that the bonds are actually *issued by a governmental body on behalf of the private party* that will use the project, but the party obligated to make payments that will cover principal and interest on the PABs is the private user. PAB owners typically cannot look to the government body for repayment.[9]

The benefits of accessing the tax-exempt bond market are lower interest rates and more favorable and flexible borrowing terms. Other things being equal (such as maturity, credit, credit ratings, and optional redemption features), the interest rate required to successfully market a tax-exempt bond will be lower than the interest rates on the equivalent taxable bond.[10]

As an additional benefit to projects, because tax-exempt bonds are primarily owned by individuals or fiduciaries for individuals such as bond mutual funds, the terms available to borrowers—such as length of repayment or provisions allowing the project owner to redeem the bonds early—are considerably more favorable than terms available in the corporate investment grade bond market or in the commercial bank market.[11]

There is ample precedent for the use of tax-exempt private activity bonds to finance the installation of pollution control facilities. The federal tax code currently contains categories for tax-exempt PAB issuance for solid waste, hazardous waste, and sewage facilities owned by private parties (Hume 2016). Such bonds are typically called "exempt facility bonds" since it is the particular type of capital expenditure (e.g., pollution control) that confers tax-exempt financing potential rather than the tax status of the facility owner. The solid waste authority is regularly used to finance certain kinds of pollution control equipment at power plants.[12] And from 1968 to 1986, an additional category existed for air pollution control facilities. During this period, America's privately owned utilities used tens of billions of tax-exempt bonds to finance new advanced air pollution control facilities such as flue gas desulfurization equipment, electrostatic precipitators, and fluidized bed boilers, both as retrofits and in new plants (Brown 2014). According to the Joint Committee on Taxation, from 1975 to 1984 (the last half of the authorized time span), $37.2 billion (~$100 billion in 2014 dollars) of these pollution control bonds were issued to fund projects whose aggregate price tag was approximately double that figure (IRS 2009). Use of tax-exempt facility bonds to fund CCUS retrofit projects would be allowed under Senators Rob Portman and Michael Bennet's Carbon Capture Improvement Act of 2019 (S. 1763, 116th Congress).

Accelerated Depreciation (AD)

Accelerated depreciation is a capital incentive that lowers the net present value of taxes paid over the life of a project. In 1986, the US government introduced the modified accelerated cost recovery system (MACRS), which is a depreciation method that allows tangible investment made by firms to be recovered, for tax purposes, over a specified time period through annual deductions. When Congress provided production tax credits and investment tax credits for renewable energy projects under Sections 45 and 48 of the tax code, Congress also put such tax-credit-eligible projects into a very favorable five-year MACRS depreciation category.

Without that provision, these projects would have been depreciated over 20 years (SEIA 2018). An example was the bonus depreciation (BD) provision approved to benefit investment in selected infrastructure such as pipeline infrastructure and refineries with the overhaul of the tax code in the tax bill of 2017. The bonus depreciation provision contained in the bill allows eligible companies to immediately write off the full costs of capital improvement instead of depreciating the new asset over time (Renshaw 2017).

Under current law, a carbon capture project that earns the bulk of its revenue from the sale of captured CO_2 is allowed to depreciate the carbon capture equipment over a five-year MACRS cost-recovery period by virtue of CO_2 falling into Asset Class #28, "Manufacture of Chemicals and Allied Products." That is, CO_2 is a basic chemical product and benefits from the favorable depreciation schedule afforded to all such manufacturers. If capture equipment is part of a larger project, and if the bulk of revenues comes from the sale of electric energy and capacity, the project could fall into the power plant category and be depreciated much more slowly.[13] Therefore, an important tax law change would be to allow five-year depreciation for the combined value of electric generation and carbon capture equipment, regardless of the proportion of project revenues derived from CO_2 sales.

Master Limited Partnerships (MLP) Tax Advantages

Certain power and industrial facilities could benefit from master limited partnership status if changes were made to the tax code. An MLP is a special hybrid corporate structure that offers the tax advantages of a partnership combined with the stock market access and liquidity normally available only to corporations.

Like ordinary partnerships and LLCs, an MLP is a pass-through entity. This means that taxable profit earned by a project structured as a partnership, LLC, or MLP is only taxed once—at the investor level. Profits earned by a corporation that files under Subchapter "C" of the tax code are taxed twice: first corporate income taxes, and second at the shareholder level on dividends received. (See footnote 13.) However, ordinary partnerships and LLCs are not allowed to tap the public stock markets, a major disadvantage for owners of such pass-through entities who would like the easy liquidity and price visibility attendant to trading on public stock exchanges.

Congress made a special exception to this general rule for MLPs. MLPs function to provide favorable pass-through tax treatment as partnerships for federal tax purposes but are allowed to raise funds by issuing and trading equity MLP ownership units in the same way a public corporation does with its shares. This treatment should generally be expected to reduce the costs of financing projects (DOE 2017).

MLP financing has been used to fund over $500 billion worth of US oil and gas pipelines as well as some coal-related infrastructure. A vast majority of the 114 publicly traded MLPs in 2019 were mostly made up of pipeline projects in the United States (Sure Dividend 2019). Typical annual issuances in the MLP market have been estimated at $50 billion a year (Carbon Capture Coalition 2019). The MLP Parity Act, which allows CCUS projects among other clean energy resources to reduce the cost of equity and make capital available at more favorable terms through MLPs, is expected to be reintroduced sometime this year. Such allowances would provide a permanent federal incentive for CCUS investment (Coons 2019).

Additionally, recent bills like Senators Jerry Moran and Chris Coons's Financing Our Energy Future Act of 2019 would see incentives such as the MLP expanded to structure project financing to deepen investment in new energy technologies such as CCUS.

Revenue Treatments

We did not examine state-based mandates for purchase of power from CCUS-enabled fossil generators. However, such purchase mandates would be very powerful incentives, were they adopted by the states. The existing 45Q tax credit is a revenue enhancement based on volume of CO_2 captured and stored. The two additional revenue incentives analyzed here either provide some volume-based tax relief (production tax credit based on kilowatt-hour [kWh] generated) or direct price support (contract for differences). The United States, of course, already uses per-kilowatt-hour production tax credits for wind energy, and the United Kingdom government uses contracts for differences (CFDs) to stabilize revenues for select clean energy projects in the UK's deregulated electricity market.

Production Tax Credit (PTC)

The renewable electricity production tax credit provides financial incentive to encourage development of renewable energy production. The government pays a specific amount for every kilowatt-hour of electricity produced ($/kWh) by any plant retrofitted with CCUS technology for a specified period of time. PTC was popular for wind, geothermal, and closed-loop bioenergy, spurring a massive increase in average investment in wind capacity in the United States to nearly $15 billion between 2007 and 2014 (Union of Concerned Scientists 2015). PTC could incentivize investment in CCUS retrofitting if the amount paid is adequate to make the investment viable and the tenure is increased to cover the project lifecycle.

Contracts for Differences (CFD)

Through its electricity market reforms, the United Kingdom instituted a contracts-for-differences framework enabling a 15-year bilateral contract between a low-carbon electricity generator and the United Kingdom Department for Business, Energy, and Industrial Strategy. The contract provides stable revenues to generators, removing the risk of volatility in wholesale electricity prices, by providing a flat reference price. The difference between the strike price (market price) and reference price is paid by DECC to the generator if the reference price exceeds the strike price, or vice versa if the strike price exceeds the reference price. This policy structure overtly closes the finance gap, providing low risk to potential investors. The United Kingdom's CFD policy has proven important in financing offshore wind projects. Although this policy has not yet been exercised in the UK for CCUS projects, it remains an important consideration for pending CCUS project proposals such as the Humber or Teesside industrial clusters which include capture on power plants.

2.0 METHODOLOGY

Choice of Assets and Asset Ownership

To assess the relative cost, merit, and structure of these policy options as applied within the US electricity sector, we developed a series of financial models of the following asset classes:

- New unabated fossil combined cycle gas turbine power plant (NGCC)
- New NGCC with CCUS installed at plant commissioning
- Existing subcritical pulverized coal combustion (PCC) power plants without capture
- Coal retrofit with CCUS

Our immediate focus is on power sector assets—natural gas combined cycle power plants and pulverized coal power plants. The choice of these two power generation asset classes is indicative of their high contribution in electricity generation. About 63 percent of the 4.18 trillion kWh of utility-scale electricity generated in 2018 was from natural gas and coal power plants (EIA 2019). These two asset types were compared based on their viability by looking at their cost and revenue streams prior to abatement and post-abatement. Future analysis will focus on new technologies and on industrial plants.

Two key issues for investment consideration are the nature of the carbon-emitting fossil power plant owner and the structure of the revenue stream in its market.

- In US power markets, owner types include regulated investor owned utilities (IOUs), privately owned independent power producers (IPPs), municipal-owned wholesale and retail electric systems (munis), and generation and distribution electric cooperatives (coops).
- Some entities have a highly predictable revenue stream, such as regulated, vertically integrated IOUs that effectively have guaranteed returns on generation and pollution control assets, the investment in which has been approved by regulators. Municipals and coops that are unregulated and thus can raise rates as needed to earn returns needed to repay debt are also considered safe investments. Still relatively safe are IPPs that have contracted with a regulated IOU to provide energy and/or capacity under a long-term fixed price power purchase agreement (PPA) that has been approved by the IOU's regulator.[14] In contrast, a "merchant generator" of fossil power in a deregulated spot-market-oriented independent-system-operator-run system such as ERCOT, PJM, NE-ISO, or New York ISO has an extremely risky business model.

We limited our options to two classes of owners: regulated, vertically integrated investor owned utilities (IOUs) and independent power producers (IPPs) that have long-term PPAs in place with a regulated IOU. These two ownership structures have different ratios of debt to equity investment, different return rates, and different risk profiles. These in turn affect the size of the financial gap and policy requirements. We anticipate assessing other ownerships classes, structures, and generating types in future work.

Input Assumptions

Key assumptions were made leveraging available information from databases of existing power plants, a number of carbon capture engineering studies, the DOE's "Fossil Baseline" cost studies, IRS regulations, and other related power sector research outcomes. Some other assumptions were made based on experience in modeling energy projects as well as in general financial modeling. For coal plants, we assumed a partial or "slipstream" retrofit representing 90 percent capture on the treated portion of total emissions (which, given an assumed 74 percent total operating rate of the coal plant, results in an approximately 76 percent capture rate of the overall CO_2 emissions on each coal unit).[15] For gas plants, we assumed a 90 percent capture rate on all emissions (with the NGCC assumed to operate at a 60 percent capacity factor).

We had to make many assumptions to complete the financial models, including cost of capital, leverage, minimum equity after-tax return rates, oil and gas prices, coal price, power sales revenues, tax rates, and more. These assumptions are detailed in the appendix. The model spreadsheets can be found at this data sharing portal.

3.0 RESULTS

To simplify discussion, we cast our results in terms of the energy prices or energy price differentials ($/MWh) that are sufficient to generate the necessary revenues or revenue equivalents (i.e., tax credits) for a facility to obtain debt funding and to attract equity investment (table AA). This provides a common basis for comparison between policy options. In all model cases, the policy is designed to allow the plant to operate in its existing market by selling all generated electricity at that price.

Our analysis assumes that if the owner of an unabated subcritical pulverized coal plant has an electricity sales revenue requirement of, for example, $40/MWh to fully cover operating and financing costs, a lower-emitting power plant must drive its electricity sales revenue requirement below $40/MWh to replace that unabated plant. If the clean plant, in the absence of incentives, has a revenue requirement of $60/MWh to cover operating and financing costs, it will not be built. In order for incentives to drive building the clean plant, the incentive must somehow buy down the clean plant's electricity sales revenue requirement by at least $20/MWh. That could be done in a number of ways, with two key categories of incentives being those that decrease costs for the clean plant—typically decreasing the annual financing burden—and those that provide extra revenues or tax incentives based upon electricity generation, carbon captured, or CO_2 sold.

- Financing costs can be lowered either by reducing the *amount* of money the project needs to raise (e.g., a large cash grant or a fully refundable ITC) or by reducing the rates that have to be paid on funds raised.
- Policies can provide additional electricity or CO_2 sales revenues (e.g., incentive payments like an electric feed-in tariff, contract for differences on electricity or CO_2, or a price floor for CO_2 sales).

Table 1 shows the effects of a number of these types of incentives.

Table 1: Estimated power prices needed for financial viability of different power plants using different policies

NGCC with CCUS (IOU)

Incentive	Electricity rate ($/MWh)	Effect of policy ($/MWh)	Assumptions
Unabated NGCC	$43.70		
CCUS with no incentive	$62.27		
CCUS with 45Q only	$52.11	**$10.16**	$50
PTC (Without 45Q)	$44.36	$17.91	$24
ITC (Without 45Q)	$58.95	$3.32	30%
ITC (With 45Q)	$48.79	**$13.48**	30%
PAB (Without 45Q)	$62.86	$(0.59)	3.2%
PAB (With 45Q)	$52.71	**$9.56**	3.2%
MLP (Without 45Q)	$61.24	$1.03	4.0%
MLP (With 45Q)	$51.08	**$11.19**	4.0%
CFD (Without 45Q)	$62.27	$ -	$16.02
CFD (With 45Q)	$52.11	**$10.16**	$5.87
BD (Without 45Q)	$61.93	$0.34	75% (Y1); 15% (Y2); 10% (Y3)
BD (With 45Q)	$51.78	**$10.49**	75% (Y1); 15% (Y2); 10% (Y3)

NGCC with CCUS (IPP)

Incentive	Electricity rate ($/MWh)	Effect of policy ($/MWh)	Assumptions
Unabated NGCC	$54.12		
CCUS with no incentive	$83.19		
CCUS With 45Q only	$73.03	**$10.16**	$50
PTC (Without 45Q)	$65.28	$17.91	$24
ITC (Without 45Q)	$78.09	$5.10	30%
ITC (With 45Q)	$67.94	**$15.25**	30%
PAB (Without 45Q)	$78.76	$4.43	5.6%
PAB (With 45Q)	$68.61	**$14.58**	5.6%
MLP (Without 45Q)	$79.97	$3.22	6.0%
MLP (With 45Q)	$69.81	**$13.38**	6.0%
CFD (Without 45Q)	$75.44	$7.75	$18.77
CFD (With 45Q)	$65.29	**$17.90**	$8.62
BD (Without 45Q)	$82.50	$0.69	75% (Y1); 15% (Y2); 10% (Y3)
BD (With 45Q)	$72.35	**$10.84**	75% (Y1); 15% (Y2); 10% (Y3)

Coal with CCUS (IOU)

Incentive	Electricity rate ($/MWh)	Effect of policy ($/MWh)	Assumptions
Unabated PCC	$24.11		
CCUS with no incentive	$44.57		
CCUS With 45Q only	$24.27	**$20.30**	$50
PTC (Without 45Q)	$35.73	$8.84	$24
ITC (Without 45Q)	$39.88	$4.69	30%
ITC (With 45Q)	$19.58	**$24.99**	30%
PAB (Without 45Q)	$45.75	$(1.18)	3.2%
PAB (With 45Q)	$25.45	**$19.12**	3.2%
MLP (Without 45Q)	$43.46	$1.11	4.0%
MLP (With 45Q)	$23.16	**$21.41**	4.0%
CFD (Without 45Q)	$44.57	$ -	$15.37
CFD (With 45Q)	$24.27	**$20.30**	
BD (Without 45Q)	$44.10	$0.47	75% (Y1); 15% (Y2); 10% (Y3)
BD (With 45Q)	$23.80	**$20.77**	75% (Y1); 15% (Y2); 10% (Y3)

Coal with CCUS (IPP)

Incentive	Electricity rate ($/MWh)	Effect of policy ($/MWh)	Assumptions
Unabated PCC	$24.11		
CCUS Without 45Q	$56.55		
CCUS with no incentive	$36.24	**$20.31**	$50
PTC (Without 45Q)	$47.70	$8.85	$24
ITC (Without 45Q)	$49.23	$7.32	30%
ITC (With 45Q)	$28.93	**$27.62**	30%
PAB (Without 45Q)	$51.82	$4.73	5.6%
PAB (With 45Q)	$31.52	**$25.03**	5.6%
MLP (Without 45Q)	$52.93	$3.62	6.0%
MLP (With 45Q)	$32.63	**$23.92**	6.0%
CFD (Without 45Q)	$47.59	$8.96	$18.39
CFD (With 45Q)	$27.29	**$29.26**	
BD (Without 45Q)	$55.56	$0.99	75% (Y1); 15% (Y2); 10% (Y3)
BD (With 45Q)	$35.26	**$21.29**	75% (Y1); 15% (Y2); 10% (Y3)

Baseline Characterizations for Unabated Coal and NGCC

To provide a baseline for comparison between different kinds of plants, we modeled the financial viability for unabated NGCC and plants with two different structures: IOU and IPP. We assume a higher hurdle rate for an IPP because of its riskier nature compared to an IOU.[16] The weighted average cost of capital of an IPP is usually higher as the price for capital to flow in is usually higher than an IOU, which affects its profitability. Thus, a higher hurdle rate is set by investors in making their decision to invest in an IPP rather than an IOU, requiring a higher power price to be profitable (table 2). Details on model assumptions can be found in the appendix.

Table 2: Estimated power prices needed for financial viability of unabated IOU and IPP plants

Unabated Assets	IOU Electricity Price	IPP Electricity Price
NGCC without CCUS	**$ 43.70**	$ 54.12
Coal without CCUS	$ 24.11	$ 24.11[17]

Unabated NGCC

IOU case

For an unabated 630-megawatt-capacity NGCC operated by an investor owned utility with a 60 percent operating rate, we assume a capital recovery factor (CRF) of 9.4 percent and a pretax weighted average cost of capital (WACC) of 6.2 percent.[18] Our model indicates that the plant would require a power price of **$43.70/MWh** to clear the hurdle rate of 10 percent equity IRR and remain a profitable investment (figure 3).

IPP case

In contrast, for an unabated 630-megawatt-capacity NGCC operated by an independent power producer with a 60 percent operating rate, we assume a CRF of 14.8 percent and a pretax WACC of 10.1 percent. Our model indicates that the IPP-owned plant would require a power price of **$54.12/MWh** to clear the hurdle rate of 15 percent equity IRR and remain a profitable investment.

Unabated Pulverized Coal Power Plant

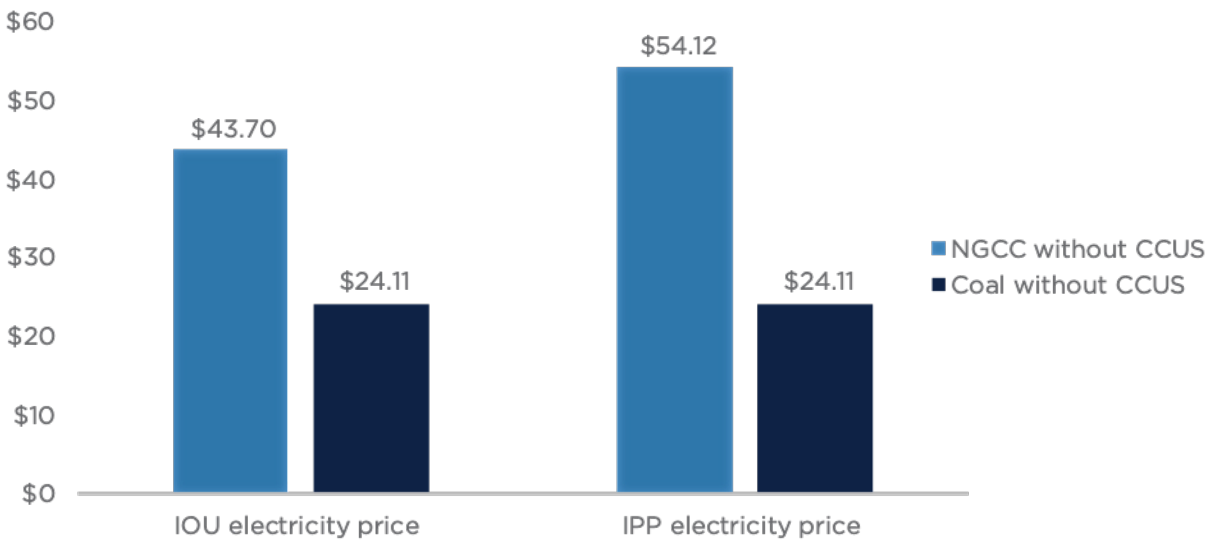
IOU case

For an unabated 500-megawatt-capacity coal plant operated by an investor owned utility with a 74 percent operating rate, we assume a CRF of 9.4 percent and a WACC of 6.2 percent. Our model indicates that the plant would require a power price of **$24.11/MWh** to clear the hurdle rate of 10 percent equity IRR and remain a profitable investment. NOTE: To be economically correct, we consider the investment in the existing coal plant to be a sunk cost. If the coal plant operator wants to shut the coal plant down and build an NGCC, it no longer has to spend $24.11/MWh variable costs in the future, but it can't get back its original investment in the coal plant.[19]

IPP case

The unabated 500-megawatt-capacity coal plant operated by an independent power producer with a 74 percent operating rate, we assume a CRF of 14.8 percent and a WACC of 10.1 percent. Since we assume identical operating costs for both the IPP and IOU-owned coal plants and no remaining debt and equity, the IPP has an identical power electricity sales revenue requirement of **$24.11/MWh**.

Figure 3: Required power price per MWh for unabated assets



Source: Energy Information Administration, 2019

Natural Gas Cases with Abatement and Various Incentives

To include the cost of carbon abatement of the NGCC plant, we modeled the incremental cost of typical carbon capture equipment for this size and capacity of power plant and added this cost to the hard cost of the NGCC, held constant. We assumed the power plant and carbon capture equipment were constructed and commissioned concurrently. Our observation was that the cost of the CO_2 capture equipment for an NGCC that treats 100 percent of emissions with a 90.7 percent capture rate is about 46 percent of the total hard costs. This substantial additional upfront construction cost strongly limits the financial viability of retrofits without additional policy support to mitigate investor risk and attract capital.

IOU case

For a 630-megawatt-capacity NGCC operated by an IOU with a 60 percent operating rate (capacity factor), we assumed a CRF of 8.7 percent and a pretax WACC of 6.5 percent. Our model indicates that the abated NGCC plant would require a power price of **$62.27/MWh**, as opposed to $43.70/MWh for the unabated IOU-owned NGCC. Consequently, to make an investment in CCUS cost-effective for the IOU's ratepayers, carbon abatement would require incentives worth $18.57/MWh. (See table 3.)

IPP case

In contrast, for a similar CCUS-enabled NGCC plant operated by an IPP, we assumed a CRF of 13.6 percent and a pretax WACC of 10.5 percent. Our model indicates that the plant would require a power price of **$83.19/MWh**, as opposed to $54.12/MWh for the unabated IPP-owned NGCC. Consequently, to make an investment in CCUS cost-effective for the IOU's ratepayers, carbon abatement would require incentives worth $29.07/MWh.

Table 3: Natural gas combined cycle new build with CCUS and no incentives ($/MWh)

NGCC Cases

	Unabated	CCUS no incentive	
	Revenue requirement	Revenue requirement	Financing gap
IOU	$43.70	$62.67	($18.57)
IPP	$54.12	$83.19	($29.07)

IOU case

When we introduced 45Q as an incentive to the CO_2 captured by the retrofitted NGCC, we assumed a generally accepted $50/metric ton (MT) rate for 45Q, levelized over the 20 years of the plant's depreciable life to $40.02/MT. Our model indicates that the abated IOU-owned plant would now require a power price of **$52.11/MWh** to remain a profitable investment, as opposed to $43.70/MWh for the unabated IOU-owned NGCC. A financing gap of $8.41/MWh remains. (See table 4.)

IPP case

For the IPP-operated NGCC power plant, introducing 45Q would equally reduce the required power price to **$73.03/MWh**, as opposed to $54.12/MWh for the unabated IPP-owned NGCC. A gap of $18.91/MWh remains.

Comparison to same cases without Section 45Q

In both the IOU and IPP cases, the addition of 45Q basically reduces the financing cap by $10.16/MWh for a retrofitted NGCC power plant. This is less than the Section 45(a) wind-production tax credit, which was $25.00/MWh in 2019 (US Government Federal Register 2019), and is insufficient at most plants to close the finance gap.

Table 4: Natural gas combined cycle with CCUS and 45Q

NGCC Cases

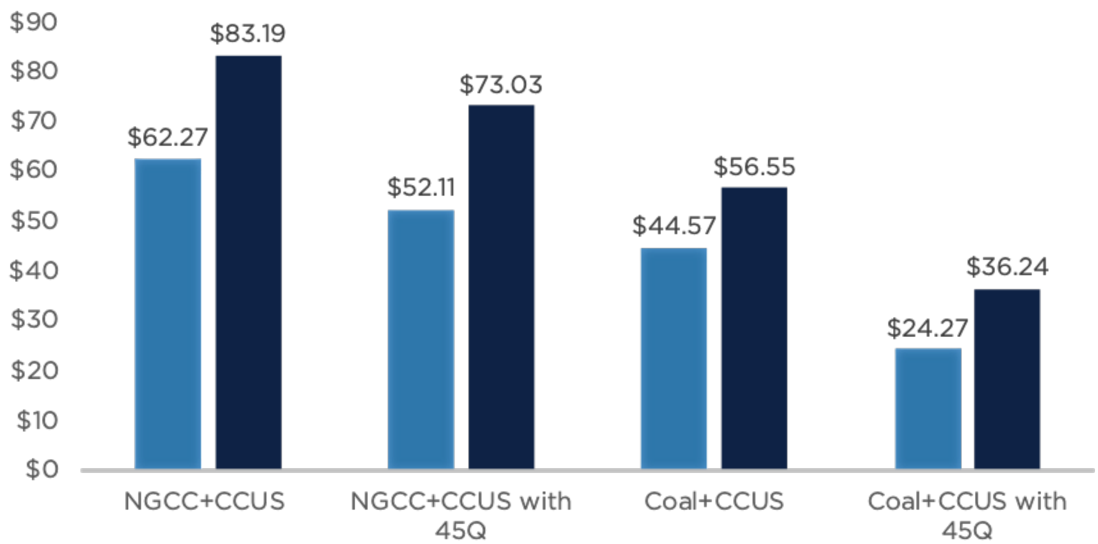
	Unabated	CCUS no incentive		CCUS 45Q incentive only		
	Revenue requirement	Revenue requirement	Financing gap	Revenue requirement	Financing gap	Δ Fin. gap vs. no incentive
IOU	$43.70	$62.67	($18.57)	$52.11	($8.41)	$10.16
IPP	$54.12	$83.19	($29.07)	$73.03	($18.91)	$10.16

We provided a summary of the estimated power price requirements to clear the hurdle rate for an abated NGCC, both for IOU and IPP ownership types (see table 5 and figure 4).

Table 5: Summary of estimated power prices needed for financial viability

	IOU ownership		IPP ownership	
	Revenue requirement $/MWh	Revenue excess (shortfall) for abated plant	Revenue requirement $/MWh	Revenue excess (shortfall) for abated plant
NGCC unabated revenue requirement	$43.70	N.A.	$54.12	N.A.
NGCC+CCUS	$62.27	($18.57)	$ 83.19	($29.07)
NGCC+CCUS with 45Q	$52.11	($8.41)	$73.03	($18.91)
Coal unabated revenue requirement	$24.11	N.A.	$24.11	N.A.
Coal+CCUS	$44.57	($20.46)	$56.55	($32.44)
Coal+CCUS with 45Q	$24.27	$0.16	$36.24	($12.13)

Figure 4: Required power price per MWh for retrofitted assets with 45Q



Retrofitted NGCC with Combined Incentives

The outcome of introducing a $50 45Q tax incentive for our retrofitted NGCC plant indicates that our plant would require additional incentives to make it as viable an investment as an unabated gas plant. To assess how policy makers might consider formulating additional incentives, we decided to build additional incentives into the model and run various scenarios to help determine what additional incentives would be combined with 45Q to make our retrofitted NGCC plant viable for investment.

NGCC: 45Q with Investment Tax Credit

IOU case

When we stacked an investment tax credit (ITC) rate of 30 percent and 45Q of $50, our model indicates that the carbon-capture-enabled NGCC plant would require a power price of **$48.79/MWh** to remain a profitable investment, as opposed to $43.70/MWh for the unabated IOU-owned NGCC. A financing gap of $5.09/MWh remains. Consequently, combining ITC and 45Q basically reduces the finance gap by $3.32/MWh, compared to the 45Q incentive only.[20]

IPP case

For the IPP-operated NGCC power plant, combining ITC with 45Q would reduce the required power price to **$67.94/MWh**. A gap of $13.82/MWh remains (see table 6).

Table 6: 45Q with investment tax credit

NGCC Cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & ITC	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$43.70	$62.67 ($18.57)	$52.11 ($8.41)	$10.16	$48.79 ($5.09)	$3.32
IPP	$54.12	$83.19 ($29.07)	$73.03 ($18.91)	$10.16	$67.94 ($13.82)	$5.09

NGCC: 45Q with Private Activity Bonds

When considering the impact of adding PABs to the incentive package, there are a number of nonintuitive factors to consider. In summary, the benefits of using PABs are much greater for an IPP than for an IOU, while the tax code's detriments are about the same for both entities. Thus, we can get the odd result of PABs helping IPPs and very modestly hurting IOUs.

First, PABs are far more helpful to IPPs than to IOUs. IOUs already have access to very low-cost bonds and long maturities because of their regulatory status (i.e., other things being equal, an IOU in a state with reasonable regulators that has had regulatory approval to sell bonds to build an approved asset is a pretty safe bet for bondholders). The absolute rate reduction benefit of a PAB depends on the taxable rate of the same credit: an individual saving 30 percent income tax on a 10 percent bond obtains a 3 percent benefit vs. saving 30 percent income tax on a 5 percent bond, which is a 1.5 percent benefit. An IOU can get 30-year debt whether taxable or tax exempt. An IPP may only be able to get a shorter-term bank loan on a taxable basis but may be able to get a 20-year maturity on a PAB.

However, the main detriment to PABs is the stretching out of depreciation. The portion of an asset that is financed with PABs is required to use a stretched-out depreciation schedule (9.5 years for CCUS) vs. a normal five-year depreciation schedule. Since, more or less, the asset cost is the same for an IOU or PAB, the detriment of using PABs is similar for both.

IOU case

We combined 45Q with private activity bonds, which reduced the interest rate for the IOU debt financing from 4 percent to 3.2 percent, and observed that PAB has a marginally harmful effect on the viability of the IOU-owned plant, as it would require a power price of **$52.71/MWh** to remain a profitable investment, as opposed to $43.70/MWh for the unabated IOU-owned NGCC. A financing gap of $9.01/MWh remains. Combining PAB with 45Q worsens the viability of the plant.[21]

IPP case

Here, the interest rate for the debt financing is reduced from 6 percent to 5.6 percent. For the IPP-operated NGCC power plant, combining PAB with 45Q would reduce the required power price to **$68.61/MWh**. A gap of $14.49/MWh remains (see table 7).

Table 7: 45Q with private activity bonds

NGCC Cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & PAB	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$43.70	$62.67 ($18.57)	$52.11 ($8.41)	$10.16	$52.71* ($9.01)	($0.60)*
IPP	$54.12	$83.19 ($29.07)	$73.03 ($18.91)	$10.16	$68.61 ($14.49)	$4.42

**Worse because the marginal rate improvement is outweighed by a longer depreciation life required when PABs are used.*

NGCC: 45Q with Master Limited Partnership

IOU case

We combined 45Q with master limited partnership status, which lowers the investment hurdle rate, and observed that it would require a power price of **$51.08/MWh** to remain a profitable investment, as opposed to $43.70/MWh for the unabated IOU-owned NGCC. A financing gap of $7.38/MWh remains. Consequently, combining MLP and 45Q basically reduces the finance gap by $1.03/MWh, compared to a 45Q incentive only.[22]

IPP case

For the IPP-operated NGCC power plant, combining MLP with 45Q would reduce the required power price to **$69.81/MWh**. A gap of $15.69/MWh remains (see table 8).

Table 8: 45Q with master limited partnership

NGCC Cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & MLP	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$43.70	$62.67 ($18.57)	$52.11 ($8.41)	$10.16	$51.08 ($7.38)	$1.03
IPP	$54.12	$83.19 ($29.07)	$73.03 ($18.91)	$10.16	$69.81 ($15.69)	$3.32

NGCC: 45Q with Contract for Differences

IOU case

A contract for differences (CFD) would not apply to an IOU-operated power plant as they are rate-based utilities. Thus, combining CFD with 45Q has the same effect as introducing 45Q as the only incentive.[23]

IPP case

CFD reduces equity risk, thus the interest rate on debt financing is reduced from 6 percent to 5.5 percent, and the hurdle rate is also lowered. For the IPP-operated NGCC power plant, combining CFD with 45Q would reduce the required power price to **$65.29/MWh**, as opposed to $54.12/MWh for the unabated IPP-owned NGCC. A financing gap of $11.17/MWh remains (see table 9).

Table 9: 45Q with contract for differences

NGCC Cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & CFD	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$43.70	$62.67 ($18.57)	$52.11 ($8.41)	$10.16	$52.11* ($8.41)	-
IPP	$54.12	$83.19 ($29.07)	$73.03 ($18.91)	$10.16	$65.29 ($11.17)	$7.74

**CFD doesn't matter for regulated IOU because it can presumably pass through changes in costs/revenues to ratepayers, as well as financing on balance sheet basis.*

NGCC: 45Q with Bonus Depreciation

IOU Case

When bonus depreciation (BD) as an incentive is combined with 45Q, our model indicates that the plant would require a power price of **$51.78/MWh** to remain a profitable investment, as opposed to $43.70/MWh for the unabated IOU-owned NGCC. A financing gap of $8.08/MWh remains.[24]

IPP case

For the IPP-operated NGCC power plant, combining BD with 45Q would reduce the required power price by to **$72.35/MWh**. A gap of $18.23/MWh remains (see table 10).

Table 10: 45Q with bonus depreciation

NGCC Cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & BD	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$43.70	$62.67 ($18.57)	$52.11 ($8.41)	$10.16	$51.78 ($8.08)	$0.33
IPP	$54.12	$83.19 ($29.07)	$73.03 ($18.91)	$10.16	$72.35 ($18.23)	$0.68

Summary for NGCC

The following are our general findings from our analysis:

1. The existing 45Q revenue stream is not enough to encourage investment in an NGCC retrofitted with CCUS; however, an enhanced 45Q of $80 for saline formation (or $65 for EOR + $15/ton offtake contract) would be adequate for an NGCC IOU. An NGCC plant owned by an IPP would require $115.50/ton for saline formation.

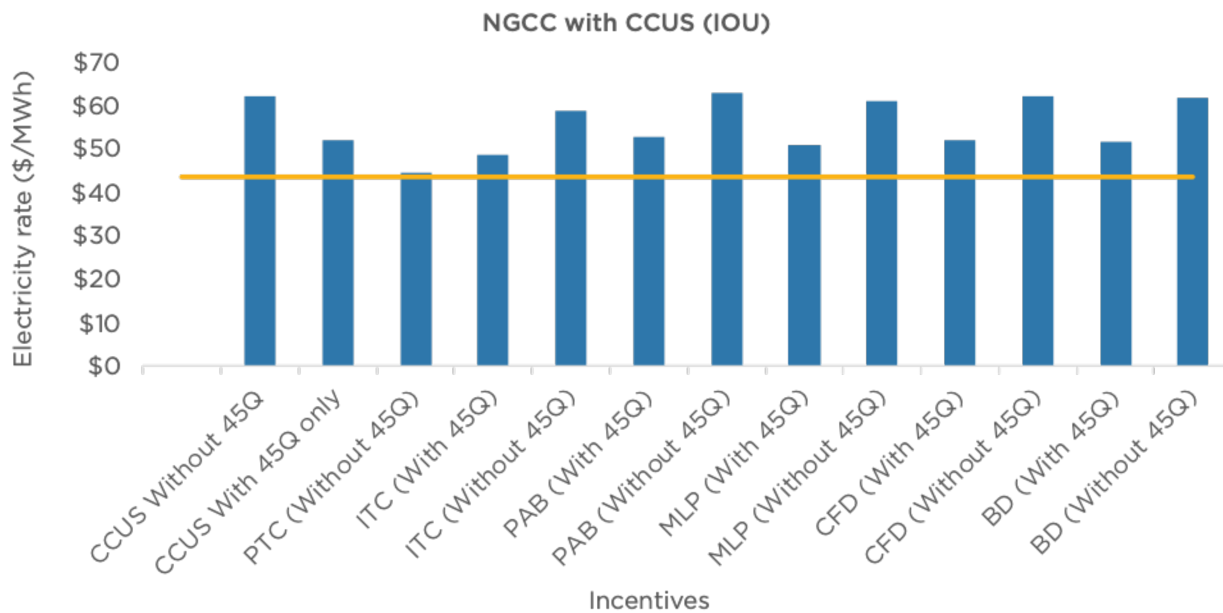
2. However, when we apply a combination of incentives in a retrofitted NGCC power plant, a PTC works better in improving viability of the plant than a 45Q of $50 in each scenario.

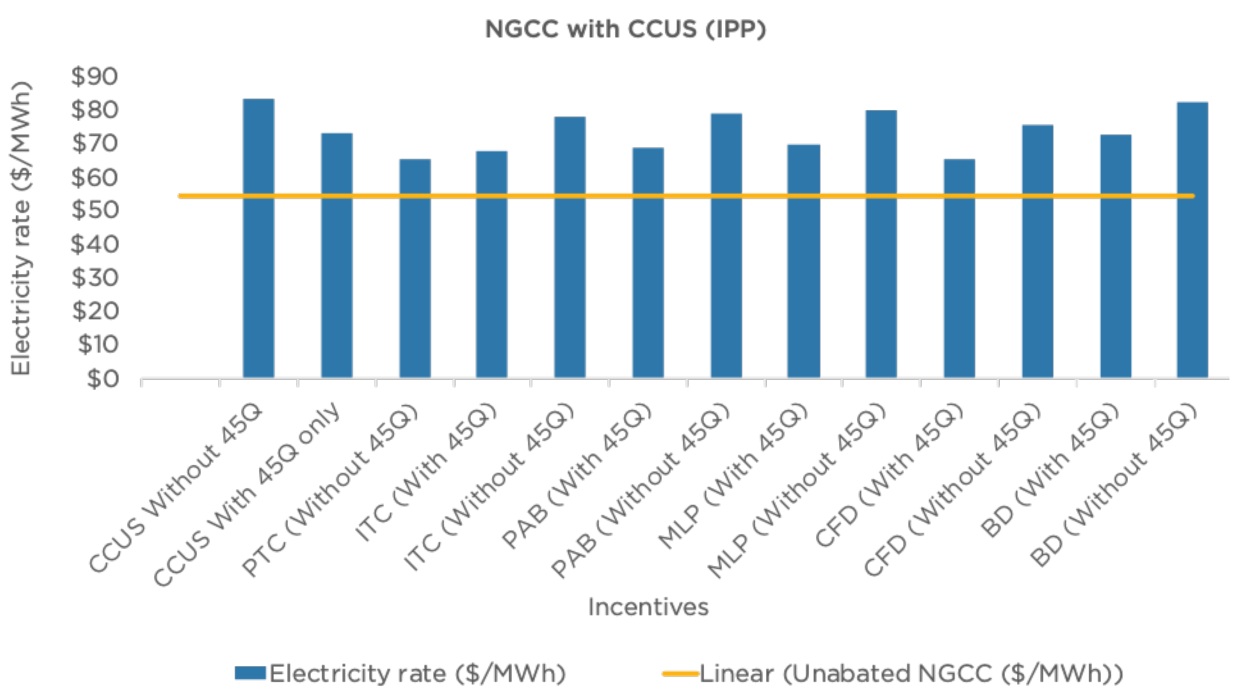
3. The PAB doesn't help the IOU because the IOU already has a very low debt rate. Thus, if we introduce a PAB, the IOU will be forced to stretch out its depreciation, affecting its viability. However, the PAB is good for the IPP.

4. A CFD is useful for an IPP-operated NGCC, as an IOU is a rate-based utility.

Figures 5 presents a summary of how the incentives weigh for NGCC plants.

Figure 5: Summary of rates for combined incentives for NGCC IOU and IPP plants





Pulverized Coal Power Plant Retrofits Without Incentives ($/MWh)

When we modeled the incremental cost of pollution control equipment with a 90 percent capture rate in a pulverized coal power plant, our findings were quite instructive. Details on model assumptions can be found in the appendix.

For a retrofitted 500-megawatt-capacity coal plant operated by an IOU with a 74 percent operating rate, assuming a CRF of 8.7 percent and a WACC of 6.5 percent, our model indicates that the plant would require a power price of **$44.57/MWh** to clear the hurdle rate of 10 percent equity IRR and remain a profitable investment. Consequently, abatement increases the required price of power to make an investment in CåCUS retrofit of an IOU coal plant profitable by $20.46/MWh.

With a similarly retrofitted plant operated by an IPP, assuming a CRF of 13.6 percent and a WACC of 10.5 percent, our model indicates that the plant would require a power price of **$56.55/MWh** to clear the hurdle rate of 15 percent equity IRR and remain a profitable investment. Consequently, abatement increases the required price of power to make an investment in CCUS retrofit of an IPP coal plant profitable by $32.44/MWh (see table 11).

Table 11: Pulverized coal power plant retrofits without incentives ($/MWh)

Pulverized coal cases

	Unabated	CCUS no incentive	
	Revenue requirement	Revenue requirement	Financing gap
IOU	$24.11	$44.57	($20.46)
IPP	$24.11	$56.55	($32.44)

Pulverized Coal Power Plant Retrofits with 45Q

IOU case

When we introduced 45Q as an incentive to the CO_2 captured by the retrofitted pulverized coal power plant, we equally assumed a generally accepted $50/MT rate for 45Q, levelized over the 20 years of the plant's depreciable life to $40.02/MT. Our model indicates that the plant would require a power price of **$24.27/MWh** to remain a profitable investment as opposed to $24.11/MWh for the unabated IOU-owned PCC. A marginal financing gap of $0.16/MWh remains.

IPP case

Contrastingly, for the IPP-operated PCC, introducing 45Q would reduce the required power price equally to **$36.24/MWh**. A gap of $12.13/MWh remains (see table 12).

Table 12: Pulverized coal power plant retrofits with 45Q

Pulverized coal cases

	Unabated	CCUS no incentive		CCUS 45Q incentive only		
	Revenue requirement	Revenue requirement	Financing gap	Revenue requirement	Financing gap	Δ Fin. gap vs. no incentive
IOU	$24.11	$44.57	($20.46)	$24.27	($0.16)	$20.30
IPP	$24.11	$56.55	($32.44)	$36.24	($12.13)	$20.30

Retrofitted Coal Plant with Combined Incentives

We also decided to build additional incentives into the model and run various scenarios to help us determine what additional incentives would be combined with 45Q to make our retrofitted coal plant viable for investment.

45Q with Investment Tax Credit

IOU case

Combining an investment tax credit rate of 30 percent with a 45Q incentive, our model indicates that the plant would require a power price of **$19.58/MWh**, as opposed to $24.11/MWh for the unabated IOU-owned PCC. Consequently, combining ITC and 45Q clears the financing gap for a retrofitted IOU-operated PCC.

IPP case

For the IPP-operated coal power plant, combining ITC with 45Q would reduce the required power price to **$28.93/MWh**, leaving a gap of $4.82/MWh to be financed (see table 13).

Table 13: 45Q with investment tax credit

Pulverized coal cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & ITC	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$24.11	$44.57 ($20.46)	$24.27 ($0.16)	$20.30	$19.58 $4.53	$4.69
IPP	$24.11	$56.55 ($32.44)	$36.24 ($12.13)	$20.30	$28.93 ($4.82)	$7.31

45Q with Private Activity Bonds

IOU case

Combining 45Q with private activity bonds, we observed that the plant would require a power price of **$25.45/MWh** to remain a profitable investment, as opposed to $24.11/MWh for the unabated IOU-owned PCC. A financing gap of $0.23/MWh remains. Consequently, combining PAB and 45Q reduces the finance gap by $0.18/MWh compared to 45Q incentive only.

IPP case

For the IPP-operated PCC, combining PAB with 45Q would reduce the required power price to **$31.52/MWh**. A gap of $7.41/MWh still remains (see table 14).

Table 14: 45Q with private activity bonds

Pulverized coal cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & PAB	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$24.11	$44.57 ($20.46)	$24.27 ($0.16)	$20.30	$24.45* ($0.23)	($0.18)*
IPP	$24.11	$56.55 ($32.44)	$36.24 ($12.13)	$20.30	$31.52 ($7.41)	$4.72

Worse because small rate improvement outweighed by longer depreciation life is required when PABs are used.

45Q with Master Limited Partnership

IOU case

When we combined 45Q with a master limited partnership, we observed that the plant would require a power price of **$23.16/MWh**, as opposed to $24.11/MWh for the unabated IOU-owned PCC. Consequently, combining MLP and 45Q gets you $21.41/MWh reduction for a retrofitted IOU-operated coal power plant. Consequently, combining MLP and 45Q clears the financing gap for a retrofitted IOU-operated PCC.

IPP case

For the IPP-operated coal power plant, combining MLP with 45Q would reduce the required power price to **$32.63/MWh**. A gap of $8.52/MWh remains (see table 15).

Table 15: 45Q with master limited partnership

Pulverized coal cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & MLP	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$24.11	$44.57 ($20.46)	$24.27 ($0.16)	$20.30	$23.16 $0.95	$1.11
IPP	$24.11	$56.55 ($32.44)	$36.24 ($12.13)	$20.30	$32.63 ($8.52)	$3.61

45Q with Contract for Differences

IOU case

A contract for differences would not apply to an IOU-operated power plant as they are rate-based utilities. Thus, combining CFD with 45Q has the same effect as introducing 45Q as the only incentive.

IPP case

CFD reduces equity risk, thus the interest rate on debt financing is reduced from 6 percent to 5.5 percent, and the hurdle rate is also lowered. For the IPP-operated coal power plant, combining CFD with 45Q would reduce the required power price to **$27.29/MWh**, as opposed to $24.11/MWh for the unabated IOU-owned PCC. A financing gap of $3.18/MWh remains. Consequently, combining CFD and 45Q basically reduces the finance gap by $8.95/MWh, compared to 45Q incentive only (see table 16).

Table 16: 45Q with contract for differences

Pulverized coal cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & CFD	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$24.11	$44.57 ($20.46)	$24.27 ($0.16)	$20.30	$24.27* ($0.16)	-
IPP	$24.11	$56.55 ($32.44)	$36.24 ($12.13)	$20.30	$27.29 ($3.18)	$8.95

**CFD doesn't matter for regulated IOU because it can presumably pass through changes in costs and revenues to ratepayers as well as financing on balance sheet basis.*

45Q with Bonus Depreciation

IOU case

Combining bonus depreciation with 45Q, our model indicates that the plant would require a power price of **$23.80/MWh**, as opposed to $24.11/MWh for the unabated IOU-owned PCC. Consequently, combining BD and 45Q clears the financing gap for a retrofitted IOU-operated PCC.

IPP Case

For the IPP-operated coal power plant, combining BD with 45Q would reduce the required power price by to **$35.26/MWh**. A gap of $11.15/MWh remains (see table 17).

Table 17: 45Q with bonus depreciation

Pulverized coal cases

	Unabated	CCUS no incentive	CCUS 45Q only		CCUS 45Q & BD	
	Revenue required	Revenue required (gap vs. unabated	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS No Incentive	Revenue required (gap vs. unabated)	Better (worse) gap vs. CCUS 45Q Only
IOU	$24.11	$44.57 ($20.46)	$24.27 ($0.16)	$20.30	$23.80 $0.31	$0.47
IPP	$24.11	$56.55 ($32.44)	$36.24 ($12.13)	$20.30	$35.26 ($11.15)	$0.98

Summary for Pulverized Coal Plants

The following are the general findings from our analysis:

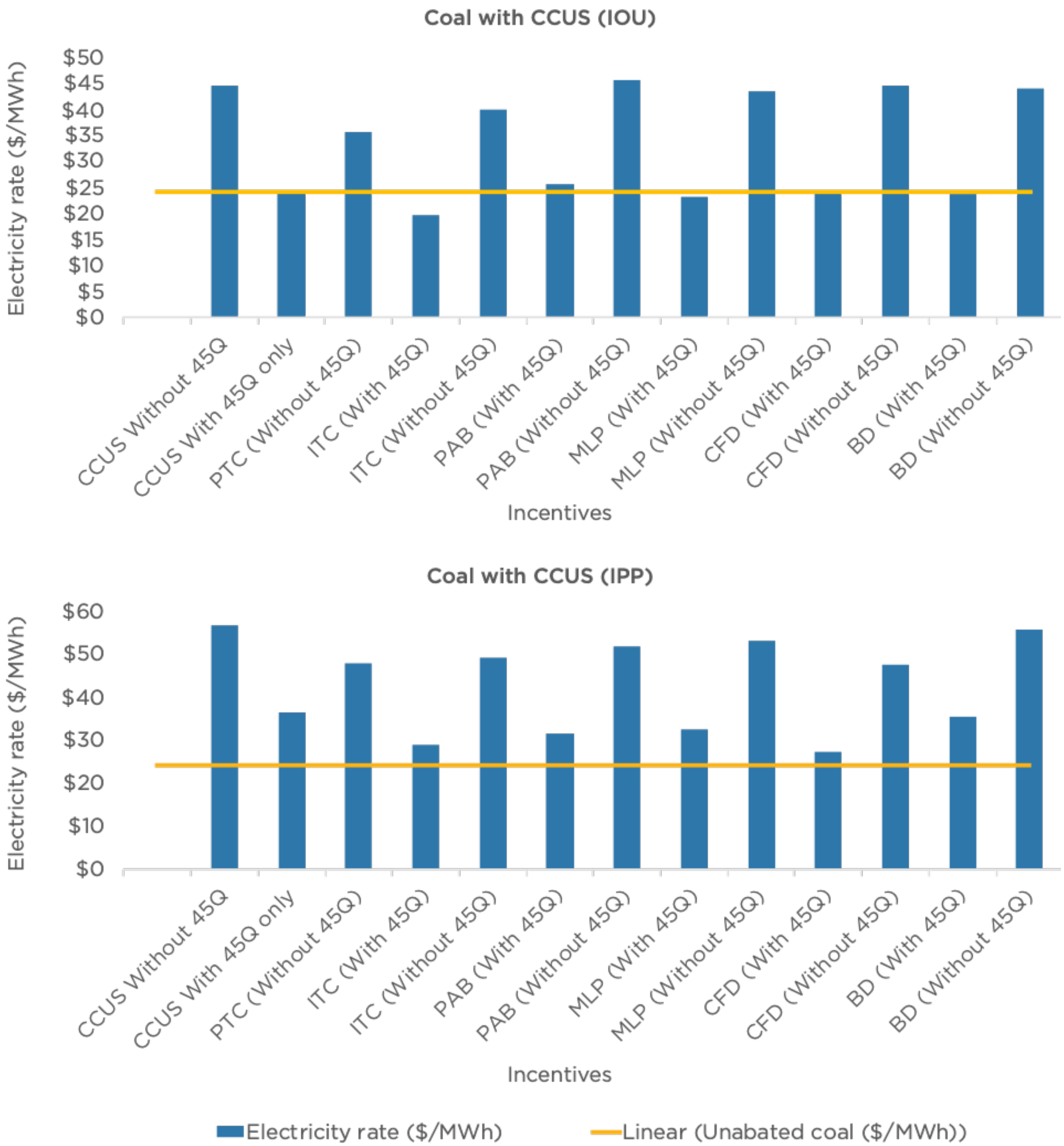
1. For a pulverized coal power plant, a combined revenue of $40.02/ton (see "Incentives Assumptions," p. 49) is not enough to encourage investment in a CCUS retrofit. However, some cases appear close, and a slight improvement of 45Q (e.g., $5 additional/ton) may be sufficient for some cases, notably IOU-owned plants (a larger incentive appears needed for IPP-owned coal plants).

2. Some capital incentives, such as MLP and ITC, appear sufficient for a retrofitted IOU-operated PCC plant when added to 45Q.

3. CFD, in conjunction with 45Q, is most useful for an IPP-operated PCC project. PAB also appears extremely helpful to IPP-operated PCC projects, but not quite enough to clear investment hurdles..

Figure 6 presents a summary of how the incentives weigh for coal plants.

Figure 6: Summary of rates for combined incentives for coal IOU and IPP plants



Enhanced 45Q as a Policy Finance Option for NGCC Plants

In addition to the policy options discussed above, there's another option that may be more politically actionable in the near term: modify or amend the existing 45Q statute. This would be most important to support retrofits for NGCC plants, which cannot make the hurdle rate today. We assess the two NGCC ownership structures below, as shown on table 18.

IOU case

Our model indicates that for 45Q to be adequate as a singular policy option to clear the hurdle rate of investment to retrofit an NGCC power plant, the tax credit has to be higher than today. Table 18 presents the result of our analysis, indicating that with an $80 45Q rate (or $65 with $15 EOR revenues) for an IOU, 45Q only would be enough to encourage investment in CCUS as it reduces the required electricity price to **$43.41/MWh** for an IOU-operated NGCC, leaving no financing gap.

IPP case

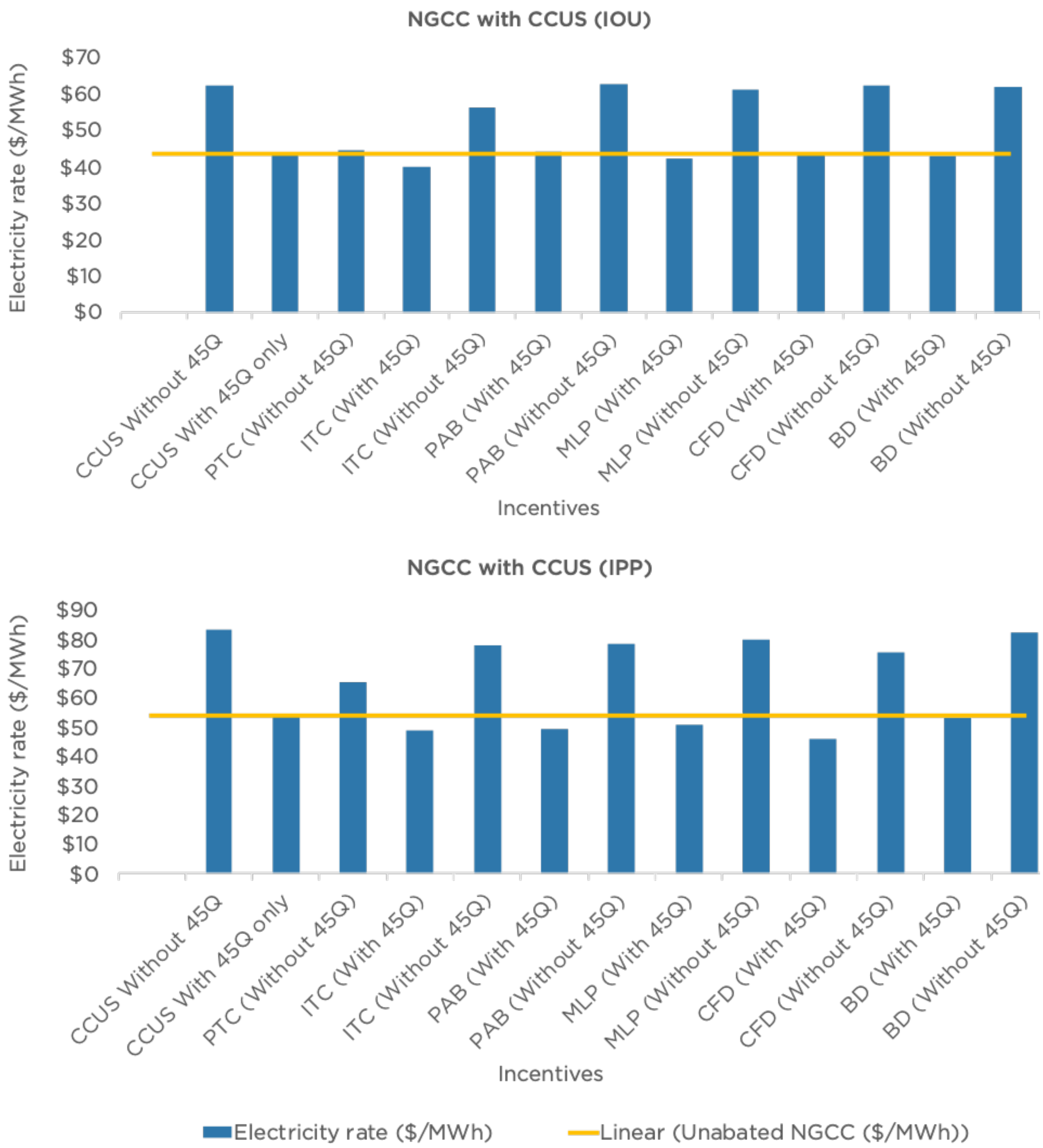
With a $100.5 + $15 45Q rate, 45Q only would be enough to encourage investment in CCUS as it reduces the required electricity price to **$54.03/MWh** for an IPP-operated NGCC, leaving no financing gap.

Table 18: Enhanced 45Q as a policy finance option for NGCC plants

	Unabated	CCUS no incentive		CCUS 45Q incentive only		
	Revenue requirement	Revenue requirement	Financing gap	Revenue requirement	Financing gap	Value of enhanced 45Q ($/MWh)
IOU	$43.70	$62.27	($18.57)	$43.41	$0.29	$18.86
IPP	$54.12	$83.19	($29.07)	$54.03	$0.09	$29.16

Figure 7 presents a summary of how the enhanced 45Q incentive clears the financing gap for the NGCC plants.

Figure 7: Summary of enhanced 45Q incentive clearing financing gap



4.0 DISCUSSIONS

Power System Context

We recognize that many power plants have already been decarbonized through shutdowns, with poor performing plants (mostly old and inefficient subcritical coal plants) closing and being replaced with natural gas power or variable renewable generation. However, rapid, deep decarbonization will require both an acceleration of these trends and decarbonization of young high-efficiency coal and gas plants; the fact that the worst performing plants have closed makes it increasingly difficult and costly to continue power sector decarbonization through closure and substitution alone.

This analysis focuses explicitly on decarbonizing power plants with the expectation that many will remain in service and continue generating power and emitting CO_2 without different policy measures (e.g., mandatory closure or unmeetable regulatory standards). In all cases, IOUs and IPPs will dominate US power generation for many years. Most US customers, 72 percent, are served by either IOUs or IPPs. It is hard to get precise information on the breakdown of ownership nationwide since these data are not collected by the US DOE, however some trends appear significant. For example, many IOUs have divested themselves or have not sought ownership of new plants, selecting instead to contract power from IPPs. This is particularly acute in the case of new natural gas plants, almost entirely owned by independent power producers. Some IOU-owned plants (especially old coal plants) have been sold to munis and coops, which have different governance and business models that can allow for lower returns and longer operational lives.

Given these conditions, rapid decarbonization of the power sector will significantly involve the two ownership structures, the two classes analyzed, and many analogous cases. Policy makers seeking to achieve rapid decarbonization must recognize the preponderance of these plant classes in the US market, their likely longevity, and how a single policy will affect each differently.

In estimating potential costs, the recent National Petroleum Council report (2019) generated cost-supply curves and estimated the likely total costs associated with these plant types, most of which fall within the "at scale" policy scenario. Reducing this cost would require either fewer plants (i.e., higher rates of premature closure) or cheaper capture technology, with costs being shared by government, ratepayers, and taxpayers. While these numbers may seem large, they are comparable to or cheaper than many other recent clean-power policy incentives with much lower effective volumes of CO_2 reduction (e.g., JP Morgan 2015; EEE 2017).

Additional Public Benefits to CCUS Deployment

As demonstrated above, providing the necessary financing and market certainty to make CCUS adoption viable would require stronger policy support than exists in most markets. While climate remains the most important driver for CCUS deployment (IEA 2019), additional motivation lies in the adjacent opportunities and services this technology provides. Some of the economic opportunities include the following:

- **Energy security:** A diverse mix of fuels is critical to energy and national security, as it reduces risk of supply disruptions and price volatility. Additionally, utilization of carbon captured for enhanced oil recovery, chemicals, and other possibilities increases domestic oil production, thereby reducing imported oil substantially.

- **Power system resilience:** Dispatchable low-carbon power is important in maintaining grid frequency and managing unexpected outages or demand surges. It also helps deliver deep decarbonization of the electric sector with the lowest total system costs (e.g., Jenkins et al. 2018). CCUS on power generation can serve this role, as well as nuclear and large-scale hydropower.

- **Labor and just transition:** Adding CCUS to existing power systems generally reduces criteria pollutant emissions like SOX, NOX, mercury, and particulates, which currently impact health, especially in disadvantaged communities. In addition, large power facilities often anchor communities and union jobs within the region, which has led to the vocal support of many unions for CCUS deployment.

- **Conventional CO_2 utilization:** In considering options for policy, both utilization and storage represent options for incentives, as is the case today with 45Q. We simplified our analysis by equalizing the policy incentives for both, such that revenues from CO_2 use would result in removal of an equivalent value in the models. In today's markets, this is not the case. For example, the revenues from CO_2 offtake contracts for enhanced oil recovery are generally larger than the incentive reduction in the 45Q framing. This frames the policy analysis here conservatively, and policies enacted at the levels proposed here might lead to greater or more rapid deployment of CCUS in the power sector (or higher returns for investors).

- **Novel CO_2 utilization and CO_2 removal:** Increasingly, scientists and entrepreneurs are discovering new pathways to use CO_2 as a feedstock to make products for commercial scale, such as cement, concrete, plastics, fuels, and durable carbon products (MacDowell et al. 2017; ICEF 2018). The markets for this approach are large and of growing interest (Carbon180 2019). To achieve widescale deployment, this technology pathway requires substantial development and investment but is largely built on the premise of captured and concentrated CO_2. Widescale deployment of carbon capture in the power sector would provide immediate and widespread opportunities for this fledgling industry. The same is true for engineered pathways to CO_2 removal, including direct-air capture (Rhodium 2019) and Bioenergy with CCUS (Platt et al. 2018).

Lawmakers may be interested in low-carbon power, decarbonizing of the existing fleet, creating jobs, supporting communities, improving public health, or industrial competitiveness. All have political value and may anchor future policy decisions.

Perhaps unsurprisingly, specific policies favor certain outcomes and can potentially create perverse incentives or consequences. As discussed above, the 45Q tax credit provides financial incentives on a $/ton basis. This has the consequence of providing the largest incentive for the most CO_2 abatement. In practice this incentive is smallest for high-efficiency gas plants and the largest for low-efficiency coal plants and may have the highest costs to the US Treasury. It is not clear that this was the intention of the law's drafters.

Our analysis suggests that policies that provide revenues tied to low-C power production have the opposite outcome. As lawmakers consider potential policies to deploy low-carbon power through CCUS, full financial consideration of the plant type, fuel type, vintage, efficiency, and ownership structure will yield outcomes consistent with their additional goals.

One important outcome is the overall improvement of CCUS as an enterprise. CCUS can play an important role in decarbonizing heavy industry and CO_2 removal (ETC 2018; Friedmann et al. 2019; ICEF 2018, 2019). Deployment of carbon capture technology in the power sector will reduce costs for many applications (Rubin and Yeh 2015). Similarly, permitting and operation of CO_2 storage sites will help establish operational protocols, help establish greater legal and regulatory certainty, and help support infrastructure for use outside the power sector.

How the public thinks about CCUS may substantively affect the ability of policy makers to legislate effectively and also affect deployment rates. Policy support for renewable energy policies (e.g., wind-production tax credits in 1992) began with virtually no public support or groundswell of political support and resulted in virtually no change in consumer behavior. CCUS may prove somewhat different due to some preexisting distrust among the public, and research indicates that the choice of policy instrument with which to incentivize various carbon removal initiatives may have a significant impact on the level of public support it enjoys (Ottermann-van Heek 2018). Ultimately, policy decisions are made politically and often independently of public understanding, acceptance, or preference.

Consideration of Supplemental Policies

As described above, the purpose of this analysis is to understand what policies would be required to attract private capital to retrofitting fossil-fueled plants with CCUS. In all above cases, the policies that provide revenues (e.g., PTC) at the required price seem best to reduce risk and overcome investor hurdle rates, with the enhanced 45Q serving as another form of PTC.

Some additional policy measures may also prove important if they lead to reductions of capital cost, operating cost, or risk. Many policies would contribute to these goals without direct financial incentives or stimulus:

- **R&D support:** Continued government investment in CCUS technology will help accelerate deployment into markets and lower total cost (EFI 2019; Sivaram and Kaufman 2019). Current bills, including the EFFECT and LEADING Acts (US Senate 2019a, 2019b), increase authorization for CCUS research including funds for front-end engineering design (FEED) studies, transformational technology development, and both pilot and demonstration projects. Increasing authorization and appropriation would be highly complementary to the finance proposals listed above, especially the LEADING Act, that support R&D on natural gas power systems and could help stimulate new US industries and manufacturing of CCUS machinery and services (NPC 2019).

- **Infrastructure:** Dedicated CO_2 pipelines and permitted storage sites are critical infrastructure for CCUS deployment (Great Plains Institute 2017). Although 5,000 miles of CO_2 pipelines exist in the United States, many regions lack these infrastructure elements. Their absence adds both risk and cost to potential CCUS projects. Policies such as the INVEST CO_2 Act (US House 2019a), the USE IT Act, and other CCUS infrastructure bills would be highly complementary to the finance policy proposals analyzed here and could help reduce project risks and costs.

- **Rate recovery:** Almost all power projects in IOUs and some IPP projects are guaranteed returns through rate recovery approved by public utilities commissions. Today, most utilities lack the legal authority to allow CCUS projects or plants in their rate case. Recently, nine states have modified their renewable portfolio standards by increasing the range of technologies allowed and through carbon-reduction ambition (100 percent) (Fitzpatrick et al. 2019). These "clean energy standards" or "zero-emissions power standards" would allow rate recovery for CCUS projects, as would the Federal Clean Energy Standard Bill (US House 2019b). These authorities would substitute for some or all of the policy proposals analyzed above.

- **Carbon pricing:** The enhanced 45Q financing thresholds are close representations of how the market might respond with equivalent carbon pricing. A carbon price equal to the enhanced 45Q described above should incentivize an IOU or IPP similarly. It is not clear that this would have the same macroeconomic outcome; many owner-operators may select early retirement or replacement, and an economy-wide carbon price may bring other kinds of zero-C power into the market at the expense of fossil generation. However, the carbon price would have to be very high ($60–$110/ton CO_2) to affect that outcome, and policy makers in countries have shied away from carbon prices of that magnitude.

Regardless of the approach, additional policies are needed to attract private capital into CCUS projects in the power sector. These complementary or supplementary policies help create a stable, reliable policy platform for investors, a necessary precursor to deployment.

5.0 FINDINGS AND RECOMMENDATIONS

Finding 1

Without additional policy measures, most US electric power markets will not support CCUS retrofits, even with the expanded 45Q credits. The amended 45Q tax credit is smaller than equivalent production tax credits for wind and solar and lacks the additional investment tax credits and mandates of renewable portfolio standards. Unsurprisingly, it is insufficient to close the financial gap for potential investors.

Finding 2

For many US power plants, the 45Q tax credit provides an average value of roughly $14/MWh: $10.02/MWh (about 1 cent/kWh) for NGCC and $20.3/MWh (about 2 cents/kWh) for subcritical coal retrofits. This is a substantial amount of support and for some industrial streams is sufficient to activate private capital markets. It provides a strong basis to build upon and lowers the hurdle for potential investors to place capital into developing CCUS projects. Since our analysis did not include any additional revenues, markets with EOR or other CO_2 utilization opportunities may benefit better.

Recommendation 1

Policy makers must begin in earnest to augment existing zero-carbon power generation policies to accelerate decarbonization through CCUS deployment. The urgency of climate change provides a basis to enact additional policies to speed the energy transition. Because CCUS is an important tool to speed decarbonization, US policy makers should seek to support greater ambition through legislation.

Since each market, state, and region has different natural resources, plant types, investment structures, etc., new policies should be crafted with the needs of the regions well considered. These can include zero-carbon power standards (e.g., California) or zero-carbon electricity credits (e.g., New York) but must focus on carbon abatement as the primary goal.

Finding 3

The hurdle is different depending on both fuel and ownership. The different debt and equity structures associated with IPP and IOU plan financing substantially affect which policies deliver abatement for which sectors, and incentives oriented toward reducing the cost of funding make less difference for IOUs that already have extraordinarily low funding costs. By the same token, since unabated coal plants produce more CO_2 per MWh than unabated gas plants, incentives based on tons of CO_2 avoided are more powerful for coal retrofits, with incentives based on the amount of low carbon generation being more helpful to NGCC capture projects. Similarly, the low break-even revenue requirements for fully amortized coal plants place a lower absolute revenue hurdle and power sales price for investment. Although perhaps obvious to some practitioners, many who are engaged in CCUS technology, policy, or finance are not familiar with these points.

Finding 4

Of the policy options explored, PTCs appear most effective at achieving deployment for NGCC, while capital treatments and CFDs appear most valuable for coal retrofits. These approaches cleared investment hurdles and achieved high rates of deployment and can also have the benefit of simpler deal structures and lower risk. Revenue enhancements including PTCs, CFDs, and enhanced 45Q have the specific benefit of paying only for the performance of CO_2 emissions reduction. It is possible to design capital incentives that would suffice to overcome investor concerns, but they would likely have to be larger than what has traditionally been considered or used to stimulate market adoption of other clean energy technologies. Revenue enhancement policies we did not assess (e.g., revenues from public-utilities-commission-approved increases in power rates) could also successfully lead to deployment.

Recommendation 2

Policy makers should consider revenue enhancement options first to accelerate clean power through CCUS. The total size of a PTC, CFD, or other revenue enhancement (e.g., feed-in tariff) may vary by fuel or owner, but the effectiveness appears high and provides the lowest risks to potential investors and would best assure the specific policy objective (delivery contingent on verified emissions reductions). In designing and implementing policies, care must be given to align markets to secondary outcomes (e.g., more or less coal, more or less gas, more or less saline formation storage) by providing the appropriate structure and level of support as well as making it simple for owners or investors to capture incentives.

Finding 5

Much more detailed financial analysis and policy design is needed. CCUS companies, technologies, and projects have matured to the level that supports detailed analysis only recently. Many variables remain to be assessed, including the potential impact of advanced technologies and the application to other sectors (e.g., heavy industry) and to CO_2 removal (see below).

FUTURE WORK PLANS

This report is the first in a series of analysis and estimates about financing CCUS projects. The work to date has highlighted many additional avenues for scholarship and many additional approaches to designing policies to spur adoption. These are a few of the research priorities analyses that scholars, including us, should consider moving forward.

- **Industrial facilities:** The analysis here only looks at power sector applications. However, CCUS will likely prove more important to decarbonizing heavy industrial operations such as cement, steel, and chemicals. Similar analysis on representative facilities would likely shed light on how best to craft policies in sectors that have broadly lacked support or policy design options.
- **Novel technologies:** The analysis here looks only at existing technologies applied to existing plants. We considered neither advanced technologies on existing plants nor new integrated facilities. To better understand the potential to deploy advanced technology using capital markets, one would need more sophisticated representation of the technical readiness, likely costs, and technical potential for adoption. Deeper techno-economic analysis would likely provide insights and frameworks that would support detailed financial analysis.
- **Estimating uptake and policy sensitivities:** As stated above, the likelihood of deployment will vary considerably as a function of the plant's location, vintage, ownership, fuel, market, proximity to storage options, and other variables. To understand the likely uptake and deployment of CCUS in actual markets, a series of sensitivity analyses are necessary to estimate the likely rate of deployment and the likely associated emissions reductions.
- **Novel policy formulations:** This study assessed traditional policy approaches to generating additional incentives for adoption. However, the rapidly changing policy landscape suggests that other approaches should be carefully considered and modeled as well. For example, the role of zero-emissions portfolio standards in the power sector, the intersection of the low-carbon fuel standard in California with vehicle electrification, and the potential to create new CO_2 utilities all could lower the hurdle rate for investors.
- **International approaches:** This study focused exclusively on US power markets and assets. In other countries, many power plants are owned by the government through state-owned enterprises (e.g., China, India). The costs of capital vary significantly around the world, as does the cost of fuel—both require assessment and analysis to understand. Finally, many countries use radically different policy measures to stimulate adoption of clean energy technologies, such as hard mandates, feed-in tariffs, and auctions. The specific national context for these ideas and the ones assessed here require additional scrutiny and modeling to provide insights to decision makers going forward.

We are only beginning to understand how financial markets and project developers will respond to CCUS policy considerations. We invite others to join us in exploring the complex set of options and opportunities that exist worldwide.

APPENDIX: KEY FINANCIAL MODEL ASSUMPTIONS

Table 19: Plant Assumptions

Assumption	Natural Gas Combined Cycle Plant		Pulverized Coal Plant	
	Unabated	CCUS Unit Size	Unabated	CCUS Unit Size
Pre-CCUS Net Plant Capacity (MW) and MW of Emissions Treated by CCS System	630	630	500	297 CCUS & 203 unabated
Operating Rate (%)	60		74	85% CCUS & 59% unabated
Construction Period (Years)	3		3	
CCUS Capture Rate (%)	0	90.7	0	90% on treated portion, 62% of full plant
Development Fees & Costs (% of Total Cost)	4		4	
Feed Costs (% of Total Cost)	1		1	
Power Fixed Operation & Maintenance Cost ($/kW)	11.54		4	
Variable Power Operation & Maintenance Cost ($/MWh)	1.66		2	
CO_2 Fixed O & M Cost ($/Net kW (Derived Incrementally)	0	5.62	0	2
CO_2 Variable O & M Cost ($/Net MWh (Derived Incrementally)	0	1.86	0	2
Property Tax on Non-CO_2 Equipment (%)	2		2	
Insurance as % Plant Cost Property (%)	0.75		0.75	

Table 20: Feedstock Assumptions

Assumption	Natural Gas Combined Cycle Plant		Pulverized Coal Plant	
	Unabated	Retrofitted	Unabated	Retrofitted
Gas Price & Coal Price ($/MMBTU)	3		2	
Net Heat Rate on Gas or Coal (MMBTU/MWh HHV)	6.629	7.466	10.00	14.139 on retrofitted portion
Oil Price (WTI in $/Barrel)	50		50	

Table 21: Capital Structures Assumptions

Incentives That Affect Assumptions	Natural Gas Combined Cycle Plant		Pulverized Coal Plant	
	IOU	IPP	IOU	IPP
Tax Rate (%)	21		21	
Equity Internal Rate of Return (%)	10	15	10	15

Incentives	IPP Capital Costs		IOU Capital Costs	
Incentives that Affect Capital Recovery Rates	IPP CRF	IPP WACC	Rate-Based IOU CRF	Rate-Based IOU WACC
Unabated Plant	14.8173%	10.0925%	9.4291%	6.1557%
Retrofitted Plant	13.6169%	10.4900%	8.7075%	6.4499%
Investment Tax Credit	10.1550%	11.6366%	6.3788%	7.3993%
Private Act Bond	11.8232%	8.4140%	9.4251%	5.3195%
Master Limited Partnerships	12.1840%	9.3097%	8.2644%	5.7537%
Contract for Differences	9.8953%	8.1568%	8.7075%	6.4499%
Bonus Depreciation	13.1441%	10.6466%	8.4720%	6.5459%

Table 22: Cost of Capital Assumptions

Assumption	Natural Gas Combined Cycle Plant		Pulverized Coal Plant	
	Unabated	Retrofitted	Unabated	Retrofitted
Cost of CCUS Equipment (% of Total Hard Cost)	0	46%	0	100
Debt Term (Years)	20		20	
Interest Rate on Debt (%)	4		6	

Incentives Assumptions

45Q

When we introduced 45Q as an incentive to the CO_2 captured by the retrofitted NGCC and pulverized coal plants, we assumed a generally accepted $50 rate ($35 + $15 for oil uptake) for 45Q, levelized over the 20 years of the plant's depreciable life to $40.02. To simulate a scenario where 45Q could be used as a singular incentive, we assumed a rate of $115.50 ($100.5 + $15).

PTC

When we introduced PTC as an incentive to the CO_2 captured by the retrofitted NGCC and pulverized coal plants, we estimated a $24 PTC rate for a 100 percent abatement, levelized over the 20 years of the plant's depreciable life to $19.2. Either 45Q or PTC would be selected by the model depending on which has a higher rate.

Table 23: NGCC & Coal Plants Without Incentives

Assumptions	Unabated		Retrofitted	
	IOU	IPP	IOU	IPP
Debt/(Total Capitalization) (%)	64.07	54.53	59.17	50.11
Interest Rate (%)	4% 20 year bond	6% 10 year loan	4% 20 year bond	6% 10 year loan
Depreciable Base (per $)	1	1	1	1
Depreciation	20 MACRS—100%		5 MACRS—100%	
Equity Internal Rate of Return (%)	10	15	10	15
Level Mortgage	0.047	0.074	0.044	0.068

Table 24: Investment Tax Credit

Assumptions	Retrofitted Plants	
	IOU	IPP
ITC Rate (%)	30	
Debt/Equity Structure (%)	43.34	37.37
Interest Rate (%)	4	6
Depreciable Base (per $)	0.7	
Depreciation	5 MACRS—70%	
Equity Internal Rate of Return (%)	10	15
Level Mortgage	0.032	0.051

Table 25: Private Activity Bond

Assumptions	Retrofitted Plants	
	IOU	IPP
PAB Term	20 year PAB	
Debt/Total Capital (%)	68.83%	70.06%
Interest Rate (%)	3.2	5.6
Depreciable Base (per $)	1	
Depreciation	5 MACRS—31.2%; 9.5 SLD—68.8%	5 MACRS—29.9%; 9.5 —70.1%
Equity Internal Rate of Return (%)	10	15
Level Mortgage Constant for Debt	0.047	0.059

Table 26: Master Limited Partnership

Assumptions	Retrofitted Plants	
	IOU	IPP
Debt/Equity Structure (%)	56.16	44.84
Interest Rate (%)	4	6
Depreciable Base (per $)	1	
Depreciation	5 MACRS—100%	
Equity Internal Rate of Return (%)	8	12
Level Mortgage	0.041	0.061

Table 27: Contract for Differences

Assumptions	Retrofitted Plants	
	IOU	IPP
Debt/Equity Structure (%)	59.17	59.13
Interest Rate (%)	4	5.5
Depreciable Base (per $)	1	
Depreciation	5 MACRS—100%	
Equity Internal Rate of Return (%)	10	12
Level Mortgage	0.044	0.049

Table 28: Bonus Depreciation

Assumptions	Retrofitted Plants	
	IOU	IPP
Debt/Equity Structure (%)	57.57	48.37
Interest Rate (%)	4	6
Depreciable Base (per $)	1	
Depreciation	5 MACRS—100%	
Equity Internal Rate of Return (%)	10	15
Level Mortgage	0.042	0.066

NOTES

1. Dr. S. Julio Friedmann (corresponding author), Center on Global Energy Policy, Columbia Univ. sf2951@sipa.columbia.edu

2. Emeka Ochu, Center on Global Energy Policy, Columbia Univ

3. Jeff Brown, Steyer-Taylor Center on Energy Policy and Finance, Stanford Univ.

4. Many workers use the terms CCS and CCUS interchangeably. This paper focuses exclusively on reduction of CO_2 emissions and considers CO_2 use with no additional revenue enhancements.

5. For the sake of brevity, we describe the credit as available to "any CO_2 capture operator who stores or uses CO_2." Technically the credit is in the first place claimable by the party that owns the capture facility as per US tax rules, as to tons of CO_2 that it captures or causes to be captured under contract, assuming it also directly or by contract injects the CO_2 into the subsurface for passive storage or use in CO_2-EOR or similarly arranges for the utilization of the CO_2 in a manner that meets the strictures of a life cycle analysis test. That tax owner of the CCS project is also allowed to assign the credit to the injector or user of its captured CO_2.

6. "Offset to the cash taxes owed by an owner" typically means reducing the taxes paid by a partner in a partnership or member of an LLC. In this paper we are generally assuming that a CCUS project is structured as a pass-through entity taxed under Subchapter K of the Internal Revenue Code. Pass-through entities include both partnerships and limited liability companies (LLCs). A pass-through entity does not pay taxes directly. Instead, it allocates its taxable income, deductions, and tax credits to its partners, and the partners then include those allocable items on their own returns. Most commonly, but not necessarily, allocations are made pro rata based on percentage ownership of the pass-through entity.

7. For certain renewable projects eligible for ITCs, the basis reduction is only 50% of the ITC. However, this extra benefit has not been afforded to carbon capture recipients of ITCs under Section 48A or 48B.

8. There are a number of subtleties packed into this sentence. Interest or in some cases accretion of original issue discount that is "tax-exempt," but capital gains are taxable to bond owners. Typically for Private Activity Bonds (a term that generally means bonds for specified types of projects that are owned or leased by nongovernmental parties) interest is not tax-exempt if the bond owner is a substantial user of the financed project. Some types of private activity bonds are subject to the alternative minimum tax and some are not.

9. We gloss over a variety of different structures here for simplicity. For instance, sometimes the project is even built by the governmental "on behalf of" a bond issuer, with the asset then being leased to the private user, whose lease payments back to the governmental body are then used to make bond payments on a back-to-back basis. These details are

unimportant for the purposes of this paper.

10. That is, if a corporate bond bears a 10% interest rate and all bond owners pay 30% tax rates, the after-tax interest rate is 7%; and in that circumstance, a PAB in which the same corporation is the obligor only needs to offer a 7% tax-free rate to investors.

11. The reason this matters is that innovative energy projects often do not have investment-grade ratings, whereas pension funds and insurance companies are highly circumscribed in their ability to own significant amounts of sub-investment grade debt. Banks have more ratings flexibility but have serious bank capital regulatory issues that make them unwilling to extend the long-term, gradually amortizing debt that projects need. Additionally, note that while optional redemption of a bank loan is easy, projects are typically required to enter into interest rate swaps to hedge risk on bank loans; and interest rate swaps can be extremely expensive to unwind if rates have dropped.

12. An example is that wet flue gas scrubbers used to take SO_2 out of power plant exhaust create gypsum when SO_2 reacts with lime. That gypsum constitutes a "solid waste" for tax-exempt-bond-issuance purposes.

13. See IRS Publication 946 Table B-2 for asset classes. When a newly commissioned project is a "poly-generation plant" selling a variety of products, tax counsel will typically advise the taxpayer that the project should be depreciated based upon which of the many product types is the biggest revenue generator. This is a complex subject that cannot be dealt with in detail here. The key thing is that a pure capture project is likely, through no special intention of Congress, to get a fast, favorable depreciation schedule,

14. This broad statement could be qualified by saying that such bilateral PPA for a fossil asset is relatively safe so long as there is a (i) capacity payment that covers all fixed costs, full amortization of debt, and needed return of and on equity capital; plus (ii) a tolling arrangement that fully covers fuel cost and variable costs incurred when the IOU directs the IPP to generate. Even better is a contract that requires the IOU to accept power and pay variable costs whenever the IPP generates.

15. This is a critical assumption. Most efficient coal plants that are important to their owners' generating portfolio are only rarely fully shut down. Coal plants also typically have a "minimum efficient turndown level" that is in the range of 40–50% of maximum operating levels. If a pollution control system is designed to treat all the exhaust gases produced at 40–50% operating levels, that pollution control system will operate almost all the time and thus benefit from high utilization rates of that expensive pollution control capital. In an environment where CO_2 emissions are not regulated at a federal or state level, adding CCUS to a coal plant to treat emissions that only occur 10% or 20% of the time is prohibitively expensive.

16. Even though we assumed the IPP has a very favorable, regulator-approved, bilateral PPA with an IOU, the IPP is still a higher risk operation than the IOU itself. A number of specific risks are completely or primarily borne by ratepayers if the IOU owns the fossil plant, with those same risks falling solely on the shoulders of the IPP under a bilateral PPA. Those owner-borne risks would include construction cost issues not allocated by contract to

the IPP's construction contractor, changes in debt refinancing rates, changes in federal tax rates, large unanticipated capital repairs, or maintenance issues not covered under contractor or vendor warranties, transmission interconnection risks, and most changes in environmental law unless specifically covered in the PPA, etc.

17. The break-even electricity prices for "Coal without CCUS" are identical for IOU and IPP in Table 2 because we assumed that there should be no cash operating cost included for repayment of investment for an unabated coal plant since that original investment is a sunk cost for the purposes of economic decision-making. For the unabated coal plant, operating costs for fuel, labor, etc. are assumed to be identical for IOU owners and IPP owners. However, once new capital has been invested for carbon capture, the difference in financing rates between IOU and IPP means prices would no longer be identical, as is shown in Table 11.

18. Recall that a pretax WACC only includes interest payments on debt and dividends on equity. The CRF includes payments of taxes, the repayment of debt principal to lenders, and return of original equity investment capital to owners. Thus, the CRF is bound to be considerably higher than the WACC—it pays for more cost items.

19. From a ratepayer point of view, if the existing coal plant does have some unamortized investment, whether the plant keeps running or is retired early, the ratepayer will usually end up paying no matter what. If the existing coal plant keeps running and there is a remaining prudently incurred regulatory book value for the coal plant, the ratepayer pays for interest, depreciation, tax, and return on equity. If the coal plant is scrapped, a regulatory transition asset is typically created, and ratepayers still pay roughly the same amount so that the utility is held harmless.

20. Note that our model is designed to select the incentive (between the 45Q & PTC) with the higher value. Consequently, for the NGCC plants, our model selects the Production Tax Credit rate of $24/MWh of electricity produced after abatement instead of the 45Q rate. Combining PTC and ITC for a retrofitted NGCC power plant reduces the required power price to $44.36/MWh for an IOU and $60.18/MWh for an IPP.

21. However, considering the functionality of the Production Tax Credit (PTC) and 45Q, we decide to combine PTC with PAB, and the power required price reduced to $44.95/MWh for an IOU and $60.85/MWh for an IPP. *Worse because the small rate improvement is outweighed by a longer depreciation life required when PABs are used.

22. However, combining MLP with PTC would reduce the required power price to $43.33/MWh for an IOU and$62.06/MWh for an IPP.

23. Combining CFD with PTC would reduce the required power price to $52.11/MWh for an IOU and $57.53/MWh for an IPP. *CFD doesn't matter for a regulated IOU because it can presumably pass through changes in costs and revenues to ratepayers as well as financing on balance sheet basis.

24. Combining BD with PTC would reduce the required power price to $44.02/MWh for an IOU and $64.59/MWh for an IPP.

REFERENCES

Brown, Jeffrey D. 2014. "Tax-Exempt Bond Financing for Power and Industrial Carbon Dioxide Capture Facilities." Policy memo on history of private activity bonds (April).

Brown, Jeffrey D. 2019. "Near-Term Opportunities for Carbon Capture and Geologic Storage in the Central US: Supply/Demand Analysis and Policy Recommendations." National Petroleum Council (December).

Carbon 180. 2019. "A review of Global and U.S. Markets for CarbonTech." (Executive Summary) https://static1.squarespace.com/static/5b9362d89d5abb8c51d474f8/t/5c0028d270a6ad15d0efb520/1543514323313/ccr04.executivesummary.FNL.pdf.

CCC. 2019. "Federal Policy Blueprint." Carbon Capture Coalition. https://carboncapturecoalition.org/wp-content/uploads/2019/06/BluePrint-Compressed-Updated.pdf.

Coons, C. 2019. "Financing Our Energy Future Act." https://www.coons.senate.gov/news/press-releases/sens-coons-moran-reps-thompson-estes-introduce-bipartisan-bicameral-legislation-to-level-the-playing-field-for-clean-energy.

EFI. 2019a. "Advancing the Landscape of Clean Energy Innovation." Energy Futures Initiative. https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5d3893cf42ab6500012929c2/1563989040048/Breakthrough+Energy+Full+Report.

EFI. 2019b. "Optionality, Flexibility, and Innovation: Pathways to Deep Decarbonization in California." Energy Futures Initiative. https://energyfuturesinitiative.org/s/EFI_CA_Decarbonization_Full-b3at.pdf.

EFI. 2018. "Advancing Large Scale Carbon Management: Expansion of the 45Q Tax Credit." Energy Futures Initiative. https://static1.squarespace.com/static/58ec123cb3db2bd94e057628/t/5d2ce5a6d73552000171a460/1563223469397/EFI_Advancing%2BLarge%2BScale%2BCarbon%2BManagement-%2BExpansion%2Bof%2Bthe%2B45Q%2BTax%2BCredit_2018.pdf.

ETC. 2018. "Mission Possible: Reaching Net-Zero Carbon Emissions from Harder-to-Abate Sectors by Mid-Century Energy Transitions Commission." http://www.energy-transitions.org/sites/default/files/ETC_MissionPossible_FullReport.pdf.

Fitzpatrick R., et al. 2019. "Clean Energy Standards: How More States Can Become Climate Leaders." Third way & The Breakthrough institute. http://thirdway.imgix.net/pdfs/clean-energy-standards-how-more-states-can-become-climate-leaders.pdf.

Friedmann, S.J., Z. Fan, and K. Tang. 2019. "Low-Carbon Heat Solutions for Heavy Industry: Sources, Options, and Costs Today," Center for Global Energy Policy, Columbia University. https://energypolicy.columbia.edu/research/report/low-carbon-heat-solutions-heavy-industry-sources-options-and-costs-today.

Global CCS Institute. 2019. "Policy Priorities to Incentivize Large Scale Deployment of

CCS." *Thought Leadership Report*. https://www.globalccsinstitute.com/wp-content/uploads/2019/04/TL-Report-Policy-prorities-to-incentivise-the-large-scale-deployment-of-CCS-digital-final-2019-1.pdf.

Great Plains Institute. 2017. "21st Century Energy Infrastructure: Policy recommendations for the development of American CO_2 pipeline networks." https://www.betterenergy.org/wp-content/uploads/2018/02/White_Paper_21st_Century_Infrastructure_CO2_Pipelines_0.pdf.

Hume, L. 2016. "IRS Disputes Tax-Exemption of Solid Waste Bonds in S.C." *The Bond Buyer*. https://www.cdfa.net/cdfa/cdfaweb.nsf/pages/28812/$file/IRS%20Disputes%20Tax-Exemption%20of%20Solid%20Waste%20Bonds%20in%20S.C.pdf.

ICEF. 2017. "Carbon Dioxide Utilization Roadmap, Innovation for a Cool Earth Forum, Ministry of Energy, Technology, and Industry, Govt. of Japan." https://www.icef-forum.org/pdf2018/roadmap/CO2U_Roadmap_ICEF2017.pdf.

ICEF. 2018. "Direct Air Capture of Carbon Dioxide, Innovation for a Cool Earth Forum, Ministry of Energy, Technology, and Industry, Govt. of Japan." https://www.icef-forum.org/pdf2018/roadmap/ICEF2018_DAC_Roadmap_20181210.pdf.

ICEF. 2019. "ICEF Industrial Heat Decarbonization Roadmap, Innovation for a Cool Earth Forum, Ministry of Energy, Technology, and Industry, Govt. of Japan." https://www.icef-forum.org/pdf2019/roadmap/ICEF_Roadmap_201912.pdf.

Intergovernmental Panel on Climate Change. 2018. "Global Warming of 1.5°C." https://report.ipcc.ch/sr15/pdf/sr15_spm_final.pdf.

International Energy Agency. 2019. "World Energy Outlook 2019." https://www.iea.org/weo2019/.

International Institute for Applied Systems Analysis. 2018. "Meeting Paris Climate Targets Will Require a Substantial Reallocation of Global Investment." www.sciencedaily.com/releases/2018/06/180618113033.htm.

IRS. 2018. "TEB Phase II—Lesson 6. Exempt Facility Bonds." https://www.irs.gov/pub/irs-tege/teb2_lesson6.pdf.

IRS. 2018. "Module E Exempt Facility Bonds." https://www.irs.gov/pub/irs-tege/teb_phase_1_course_11204_-6module_e.pdf.

Jenkins, J. D., M. Luke, and S. Thernstrom. 2018. "Getting to Zero Carbon Emissions in the Electric Power Sector." *Joule*, vol. 2: 2487-2510. https://www.cell.com/joule/pdf/S2542-4351(18)30562-2.pdf.

JP Morgan. 2015. "A Brave New World: Deep decarbonization of the electricity grids.". http://energyforhumanity.org/resources/reports-en/brave-new-world-deep-decarbonization-of-electricity-grids/.

Luderer, G., M. Pehl, A. Arvesen, et al. 2019. "Environmental Co-Benefits and Adverse Side-

Effects of Alternative Power Sector Decarbonization Strategies." *Nature Communications* 10: 5229. https://www.nature.com/articles/s41467-019-13067-8.

MacDowell, et al. 2017. "The Role of CO_2 Capture and Utilisation in Mitigating Climate Change." *Nature Climate Change* (April 5).

National Petroleum Council. 2019. "Meeting the Dual Challenge: A Roadmap to At-Scale Deployment of Carbon Capture, Use, and Storage in the United States." https://dualchallenge.npc.org/downloads.php.

Organization for Economic Cooperation and Development (OECD). 2017. "Investing in Climate, Investing in Growth—A Synthesis." http://oe.cd/g20climate.

Offermann-van Heek, Julia. 2018. "Trust and Distrust in CCUS Industry as Relevant Factors for the Acceptance of Carbon-Based Products." *Frontiers* (August). https://www.frontiersin.org/articles/10.3389/fenrg.2018.00073/full.

Platt, D., M.H.W. Workman, and S. Hall. 2018. "A novel approach to assessing the commercial opportunities for greenhouse gas removal technology value chains the case for a negative emissions credit in the UK." *Journal for Cleaner Production*. https://www.sciencedirect.com/science/article/pii/S0959652618326520.

Potsdam Institute for Climate Impact Research (PIK). 2019. "Decarbonizing the Power Sector: Renewable Energy Offers Most Benefits for Health and Environment." *ScienceDaily* (November 19). https://www.sciencedaily.com/releases/2019/11/191119075306.htm.

Renshaw, J. 2017. "U.S. Tax Overhaul Likely to Spending by Refiners, Pipeline Companies." https://uk.reuters.com/article/us-usa-tax-energy/u-s-tax-overhaul-likely-to-spur-spending-by-refiners-pipeline-companies-idUSKBN1EK18Q.

Rhodium. 2019. "Capturing Leadership: Policies for the US to Advance Direct Air Capture Technology." https://rhg.com/wp-content/uploads/2019/05/Rhodium-DAC-Report-Release.pdf.

Solar Energy Industries Association (SEIA). 2019. "Solar Investment Tax Credit." https://www.seia.org/initiatives/solar-investment-tax-credit-itc.

Sivaram V. and N. Kaufman. 2019. "The Next Generation of Clean Energy Tax Credits." Center on Global Energy Policy, Columbia University. https://energypolicy.columbia.edu/research/commentary/next-generation-federal-clean-electricity-tax-credits.

Sure Dividend. 2019. "2020 MLP List: 114 Publicly Traded MLPs." https://www.suredividend.com/mlp-list/.

UN Environmental Programme. 2018. "Leading International Organizations Commit to Climate Action." https://www.unenvironment.org/news-and-stories/press-release/leading-international-organizations-commit-climate-action.

UN Environmental Programme. 2018. "Emissions Gap Report 2018." http://wedocs.unep.org/bitstream/handle/20.500.11822/26895/EGR2018_FullReport_EN.pdf?isAllowed=y&sequence=1.

US Energy Information Administration. 2018. "Frequently Asked Questions." https://www.eia.gov/tools/faqs/faq.php?id=427&t=3.

US Energy Information Administration. 2018. "U.S. Energy-Related Carbon Dioxide Emissions 2018." https://www.eia.gov/environment/emissions/carbon/pdf/2018_co2analysis.pdf.

US Government Federal Register. 2019. "Credit for Renewable Electricity Production and Refined Coal Production, and Publication of Inflation Adjustment Factor and Reference Prices for Calendar Year 2019." https://www.federalregister.gov/documents/2019/06/06/2019-11810/credit-for-renewable-electricity-production-and-refined-coal-production-and-publication-of-inflation.

US House. 2019a. "Investing in Energy Systems for the Transport of CO_2 Act of 2019." https://www.congress.gov/bill/116th-congress/house-bill/4905/text?q=%7B%22search%22%3A%5B%22bustos%22%5D%7D&r=1&s=5.

US House. 2019b. "Clean Energy Standard Act of 2019." https://www.congress.gov/bill/116th-congress/house-bill/2597/text.

US Senate. 2019a. "Enhancing Fossil Fuel Energy Carbon Technology (EFFECT) Act." https://www.energy.senate.gov/public/index.cfm?a=files.serve&File_id=9B383CA2-97EF-4C61-93A6-60B740BFC2B0.

US Senate. 2019b. "Launching Energy Advancement and Development through Innovation for Natural Gas (LEADING) Act." https://www.congress.gov/bill/116th-congress/senate-bill/1685/text.

COLUMBIA | SIPA
Center on Global Energy Policy