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Comparative Analysis of Carbon Capture and Storage Finance Gaps and the Social Cost of Carbon

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Abstract: This paper evaluates how changes in economic market and policy conditions, including the establishment of a per-unit tax on unabated emissions of carbon dioxide (CO_2) set equal to estimates of the social cost of carbon (SCC), influence the economics of carbon capture and storage (CCS) for two hypothetical power generation facilities located in the United States. Data are provided from modified versions of models and resources created and managed by the National Energy Technology Laboratory. Changes in economic market and policy conditions are evaluated over a series of scenarios in which differences in the levelized cost of electricity (LCOE) provide estimates of the financial gap necessary to overcome for CCS to be considered the cost-minimizing choice for each power generation facility type considered. Results suggest that for the coal and natural gas power generation facilities considered, a per-unit tax set equal to an SCC exceeding \$123 per metric ton of CO_2 (/tCO_2) emitted (2018 dollars) and \$167/tCO_2 emitted, respectively, in combination with current Section 45Q tax credits, yields investment in CCS as the cost-minimizing choice; SCC values as low as \$58/tCO_2 and \$98/tCO_2 can make CCS the cost-minimizing choice with additional support policies (e.g., free transportation and storage options).

Keywords: social cost of carbon; carbon capture and storage; negative externality; financial gaps; economic efficiency

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1. Introduction

Carbon capture and storage (CCS), which refers to the process of capturing carbon dioxide (CO_2) from anthropogenic sources (i.e., power generation and/or industrial processes) and permanently storing the captured CO_2 underground, so as to prevent excess emissions of CO_2 from entering the atmosphere, is considered an integral component to achieving decarbonization [1–5]. The United States (U.S.) Department of Energy (DOE)'s National Energy Technology Laboratory (NETL) has contributed to research and development (R&D) related CCS for nearly two decades [6,7]. Consistent goals of NETL's CCS R&D have been to develop next-generation CCS technologies that can successfully prevent or remove atmospheric CO_2 emissions, to reduce the cost of CCS technology implementation across all three segments of the CCS value chain (i.e., CO_2 capture, transportation, and storage), and to safely and permanently store or find alternative uses for captured CO_2 [6,7].

Despite these efforts, CCS has yet to be deployed at the scale or rate necessary to achieve the CO_2 emissions reduction targets set in many of the low-carbon future energy scenarios being considered [1–3,8,9]. Across the globe, it is estimated that roughly 33 million metric tons of CO_2 (MtCO_2) is being captured and stored per year (mostly as part of enhanced oil recovery [EOR]) based on values reported in 2019 by the International Energy

Agency [2]. However, energy outlook analyses estimate CCS would be needed on the scale of upwards of 1500 $MtCO_2$ being captured per year by 2030 and on the order of over 5000–10,000 $MtCO_2$ being captured per year by 2050 to meet emissions targets [10–12].

Furthermore, while CCS has been implemented successfully in some places throughout the U.S.—examples include the Illinois Industrial Carbon Capture and Storage Project and Illinois Basin Decatur Project onshore), the Weyburn-Midale CO_2 Project (onshore), the Petra Nova Carbon Capture Project (onshore), and DOE's Regional Carbon Sequestration Partnerships Initiative (on-shore)—CCS still faces challenges related to financing and overall cost-effectiveness [4,13–16]; the latter of which is influenced by not only public policies and sponsored programs designed to lower the cost of implementing CCS but also changes in economic and market policy conditions surrounding the choice to invest in CCS. If decarbonization is to remain a key policy objective, then an analysis of the influence that economizing policies and programs, in conjunction with changes in economic and market policy conditions, have on the decision to invest in CCS is needed.

To conduct such an investigation, using scenario analysis, this paper analyzes hypothetical investments in CCS under different economic and market policy conditions for two theoretical, conventional (i.e., coal and natural gas fired) U.S.-located power generation facilities. Scenarios considered are based on current economizing policies and programs in place and changes in economic and market policy conditions (e.g., availability of and eligibility to receive tax credits for CCS and transportation and storage costs for captured CO_2) known to influence the financial feasibility of CCS investments.

One market policy condition considered across the scenarios is the payment of a per-unit tax on unabated emissions of CO_2, set equal to a range of recent estimates for the social cost of carbon (SCC). As an economic construct, the SCC identifies the incremental value of the damages associated with emitting one additional metric ton of carbon dioxide (tCO_2), or its equivalent, and is perhaps the single most important concept in the economics of decarbonization [17–19]. When evaluated along the socially optimal path for CO_2 emissions, the SCC works as a Pigouvian tax (i.e., the per-unit tax amount needed to restore emissions of CO_2 to some economically efficient level) [20].

Public policy and decision makers rely on the SCC to provide estimates of the economic costs and benefits of decisions that could alter the amount of CO_2 emissions present in the atmosphere [19]. Theoretically, if agents engaged in activities that generate CO_2 emissions were to be charged a per-unit tax set equal to the SCC, then to avoid paying the tax, they could invest in alternative carbon mitigation strategies. Theoretically, agents would do so, as long as the per-unit cost of the investment was lower than the SCC or, equivalently, if their lifetime tax liability from emitting tCO_2 was greater than the lifetime cost of their investment [20].

Other economic and market policy conditions considered across scenarios include changes in current federal policies designed to support CCS in the U.S., including Section 45Q of the Internal Revenue Service Tax Code, hereafter referred to as Section 45Q. Originating in 2008, Section 45Q provides an annual performance-based tax credit able to be claimed by a CO_2 capture project, when resultant CO_2 is either securely stored in a geologic formation (e.g., saline reservoir) or used to produce other products including oil, through CO_2- EOR [21,22]. Credits earned under Section 45Q can be applied against the carbon capture entity's tax liability or transferred to the entity disposing/utilizing the CO_2, as well as traded on the tax equity market [23].

When first established, Section 45Q was intended to provide technology-neutral incentives to reduce emissions of CO_2 from anthropogenic sources. However, a few CO_2 capture projects, beyond those near potential CO_2 EOR sites, were undertaken as the original tax credit failed to adequately reduce the financial gap between the amount of revenue being generated from the project and the cost associated with CCS implementation needed for CCS to be considered a cost-minimizing choice in addition to the financial uncertainty from the imposed project cap of 75 million tCO_2 [22,24].

In 2018, the U.S. Congress passed the Bipartisan Budget Act, which prompted revisions to Section 45Q including changes in eligibility requirements and a modification to the amount of the tax credit available. To be eligible for Section 45Q, a carbon capture project now must begin construction by 24 January 2024 and capture a requisite amount of CO_2 each year. The requisite amount depends on the type of facility or source of CO_2 emissions (e.g., industrial or power generation), the magnitude of the source's pre-capture CO_2 emissions, and the type of secure storage ensured by the project (i.e., geological storage or storage for EOR). Qualified sources for long-term storage must capture and store more than an annual rate threshold of 500,000 tCO_2 per year for power generating facilities and 100,000 tCO_2 per year for industrial or direct air capture facilities. Eligible projects can receive up to \$35 per metric ton of CO_2 (/tCO_2) captured and stored for EOR and up to \$50/tCO_2 captured to be stored in a geologic reservoir. Once in service, eligible projects are able to receive the tax credit from Section 45Q for up to 12 years.

The new provisions to Section 45Q are designed to incentivize investments in CCS by providing a greater dollar amount for each tCO_2 captured and stored, which could help close the financial gap between the revenue generated and costs associated with investment in CCS, thus yielding CCS as a cost-minimizing choice [25–27]. Expanded commercial deployment of CCS [28–30], development of CCS infrastructure, and an increase in CCS-related job opportunities [31] along with reduced emissions of CO_2 have all been noted as potential positive impacts that could result from 2018 provisions to Section 45Q.

Alternatively, others suggest that further modifications to Section 45Q will be required to make CCS more financially feasible [32]—particularly given the comparatively high costs of capture (\$45/tCO_2 to \$119/tCO_2 in 2018 dollars (2018\$) as reported by NETL in 2019) [33] relative to financial incentives available [34]. The potential financial benefits from theoretically increasing the monetary value of the per tCO_2 credits available under Section 45Q toward investment in CCS have been discussed by Sanchez et al. (2018) [35] and Victor et al. (2019) [36]. Moreover, extending eligibility under Section 45Q beyond 12 years has also been suggested by Esposito et al. (2019) [24] and King et al. (2020) [37].

This paper, however, represents the first known attempt to compare the decision to invest in CCS based on the unique business-cases for two specific CO_2-generating conventional generation resource types given (1) the option to take advantage of current economizing policies in place intended to financially incentivize CCS deployment (e.g., Section 45Q), coupled with (2) other changes in economic and market policy conditions that could potentially help to close the financial gap between the revenue generated and costs associated with investment in CCS, and (3) the establishment of a per-unit tax on unabated emissions of CO_2 set equal to a range of estimates for the SCC. The range of values of the SCC are assessed with each scenario, and values are based on recent reported estimates of the SCC available in literature.

Other changes in economic and market policy conditions span a multitude of considerations and are based on existing, theoretical, and/or additive (existing + theoretical) CCS-based economic and market policy changes. These policies include current eligibility requirements of Section 45Q with and without provisions to the credit (provisions include an expansion of the 12-year cap on eligibility to 30 years), a variant to the default U.S. Environmental Protection Agency (EPA) 50-year post-injection site care (PISC) requirement for long-term CO_2 storage sites (down to 10 years), and the elimination of storage and/or transportation costs.

Assuming a set annual after-tax rate of return, the levelized cost of electricity (LCOE) per megawatt hour (2018 \$/MWh) of electricity was first calculated for each plant type considered under the baseline, business as usual (BAU) scenario where no CO_2 abatement or per-unit tax on emissions is assumed. The LCOE refers to the estimated value of the revenue required per unit of electricity delivered for the build and operation of a power generator to be considered economically feasible, over a specified cost recovery period [38]. For power generators, considering changes in the LCOE can be used to assess the financial feasibility of different technology options.

A second scenario (referred to as BAU_SCC) was then modeled, which assumed that a per-unit tax on CO_2 was applied to 100% of generated but unabated CO_2 emissions for each plant. Results of this scenario were used to estimate the subsequent LCOE under the range of SCC values assumed. Next, the LCOE assuming plants retrofit to capture, transport, and store 90% of their generated CO_2 (i.e., invest in CCS), under the variety of changes in CCS market policy conditions and SCC configurations explored, was estimated. Estimated values for the LCOE across these different CCS policy and SCC configuration scenarios were then compared to the corresponding LCOEs estimated under BAU_SCC (where no CO_2 abatement occurs). All costs for each scenario were measured in nominal 2018 dollars.

Comparisons of scenario results provided indicators of either (1) the remaining financial gap (i.e., difference between the LCOE for the electricity producer incurring a tax equal to an estimate of the SCC with and without CCS) that must be overcome for CCS to be considered an economically practicable (i.e., the cost-minimizing) option for each hypothetical power generation facility considered when different types of CCS-based incentives are available or (2) the required CCS policy/SCC value combinations that may likely promote adoption of CCS as a CO_2 management strategy. In the era of decarbonization, analysis results help to inform the reforms and policy changes that may be necessary to demonstrably improve progress towards lowering atmospheric emissions of CO_2 using available technology.

The remainder of this paper is organized as follows. Section 2 provides an overview of how the SCC can be applied as a per-unit Pigouvian tax to correct for the negative externality associated with emissions of CO_2 from the production of electricity or another energy-intensive product. Section 3 discusses the data and models used for the analysis including key parameters for the scenarios developed as part of the study. Section 4 provides an overview of the results, including a discussion on how the SCC as a per-unit tax on emissions influences the decision to invest in CCS for the two power plant types considered. Section 5 discusses implications of the results in terms of CCS in an alternative, low-carbon energy future.

2. Materials: Negative Externalities and the Social Cost of Carbon

Externalities are said to occur when the production or consumption activities of some economic agent unintentionally impact the welfare of another agent and no compensation has been paid [39,40]. Externalities can be either positive or negative. Positive externalities impose external benefits on third-party agents not directly engaged activities, while negative externalities impose external costs [39,40]. With both positive and negative externalities, in the absence of intervention, the unintentional impacts remain external to the decisions of the responsible agents.

In the case of electricity production or the production of other energy-intensive products, resultant CO_2, and other greenhouse gas emissions impose external costs on third-party members of society. These costs are not fully accounted for by firms responsible for producing electricity or other energy-intensive products when determining their profit-maximizing level of output, resulting in a negative externality [39,40]. Figure 1 provides an example illustration of the negative externality imposed by emissions of CO_2 from the production of electricity or another energy-intensive product X by a single firm j.

In Figure 1, the demand for electricity or the energy-intensive product X is represented by D, the private marginal costs associated with production of X is represented by MC_p, and the external costs imposed on members of society is represented as MC_E. If firm j were to only consider its own private marginal costs when determining its profit-maximizing output level of X, in a perfectly competitive market environment, it would produce a quantity of X equal to X_M, which would be sold at a price equal to P_m and the market would clear at point A (i.e., the outcome that maximizes private producer surplus). Under this scenario, however, an inefficient market outcome results, because in balancing its costs and benefits at the margin, firm *j* ignores the external cost emissions of CO_2 imposed on third-party members of society from the production of *X* [39,40].

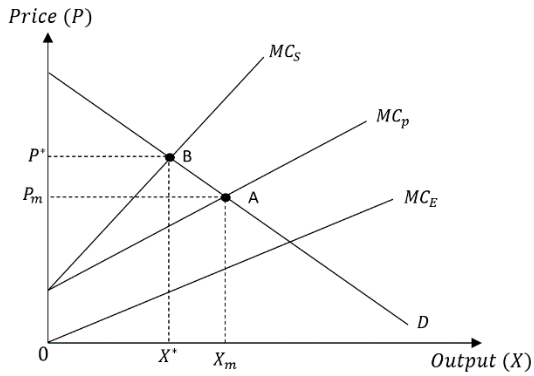

Figure 1. Depiction of a negative externality.

For economic efficiency to be achieved, these external costs must be simultaneously considered by firm *j* with its private production costs when determining its profit-maximizing level of output. In Figure 1, the summation of private (MC_p) and external costs (MC_E) from producing additional units of *X* is represented by the social marginal cost curve MC_s. The profit-maximizing output level of firm *j* when considering the full social marginal costs of producing *X* is an output level of *X* equal to X^* being produced and sold at a price equal to P^* and the market clearing at point B.

However, in the absence of intervention, firm *j* has no incentive to account the external costs associated with the production of *X* from increased emissions of CO_2 and subsequently adjust its level of production to be equal to X^*. One way to incentivize firm *j* to consider the external costs from emissions would be for a regulatory agency (e.g., the government) to impose a per-unit, Pigouvian tax (τ) on emissions of CO_2 resulting from the production of *X* [39,40]. For the tax to result in an output level of X^* being produced and sold at price P^*, it would need to be equal to the shadow price of the negative externality caused by the emissions of CO_2.

The shadow price of the negative externality from emissions of CO_2 can be inferred from the point where the value of the marginal damages associated with CO_2 emissions from the production of *X* is equal to value of the marginal benefits provided by the production of *X* that results in emissions of CO_2, as displayed in Figure 2 [39,40].

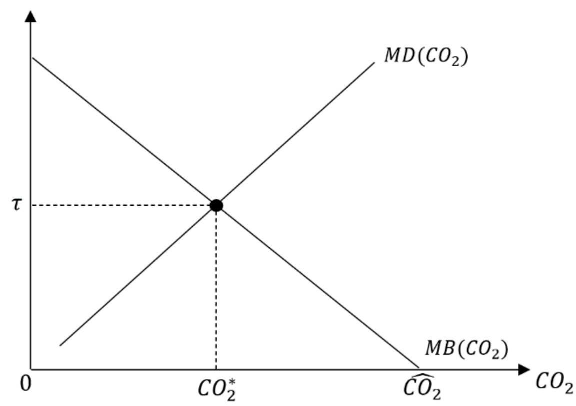

Figure 2. Net benefit maximization of level of CO_2 emissions.

In Figure 2, if the cost of the externality was not internalized by the firm *j*, emissions of CO_2 would be equal to $\hat{CO}_2$, where the marginal benefits of CO_2 emissions resulting from the production of one additional unit of *X*, labeled as $MB(CO_2)$, are equal to zero [4].

However, if a Pigouvian tax equal to τ was imposed for each unit of emissions produced by the firm, then emissions would fall to their first-best level, labeled in Figure 2 as CO_2^*. Under this scenario, the first-best level of emissions corresponds to the net benefit maximizing level of CO_2 emissions, inferred by the intersection of the marginal benefit curve, MB_{CO_2}, and marginal damage curve, MD_{CO_2}. The assignment of the Pigouvian tax, τ, alters the structure of the payoffs that face firm j, who is responsible for the externalities which the tax is designed to correct.

In addition to the private marginal costs of production, agents now must consider the costs associated with abating emissions of CO_2, which are equal to the amount of the tax paid. In order for the first-best level of CO_2 emissions to be achieved, the marginal costs of abating emissions would need to be equal to the marginal external costs borne by third-party members of society at the economically efficient output level of X^*, as displayed in Figure 3.

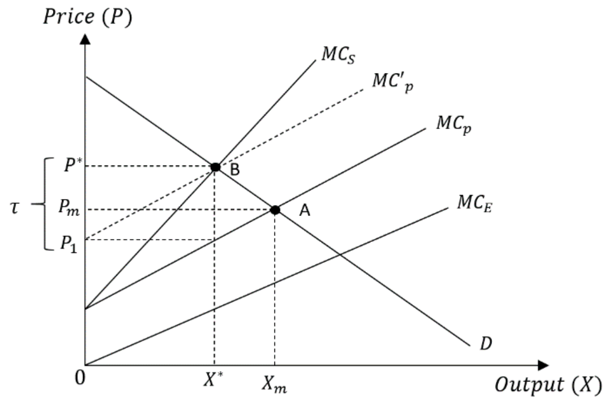

Figure 3. Pigouvian tax correction for a negative externality of emissions.

If the per-unit, Pigouvian tax was in place, the efficient outcome X^* is also the cost-minimizing choice for firm j. The marginal cost of firm j, MC_p' is equal to the prior marginal cost plus the amount of the tax, $MC_p + \tau$. Aggregating to include all j firms who produce units of X that result in emissions of CO_2, the same results hold.

From a theoretical perspective, however, to avoid paying the tax, agents engaged in activities that generate CO_2 emissions may participate in alternative carbon mitigation strategies [4,20]. CCS represents one potential alternative strategy available to firms whose production processes generate emissions of CO_2. CCS investments, however, are not cheap because CCS project costs must consider two components: (1) the cost of capturing the CO_2 emissions and (2) the cost to store what is captured, which involves transporting captured CO_2 [4]. Firms, however, will invest in CCS so long as the private marginal benefits from investing are enough to cover their additional marginal costs.

In the event that a per-unit tax on emissions is in place, marginal benefits provided from investments in CCS would include a lower overall tax liability. However, while the idea of implementing a per-unit tax on emissions equal to τ in order to achieve an economically efficient outcome can be described rather easily theoretically, it is difficult in practice to determine the value of τ necessary to achieve such a result. As with other pollutants, emissions of CO_2 have the potential to cause different types of damages (e.g., health damages, amenity loss, and damages to ecosystem functions). In many cases, the values of the damages are difficult to quantitatively estimate and cannot be compared to one another.

Nevertheless, attempts to assign a value to the damages from emissions of CO_2 have been made in the form of estimated values for the SCC. As mentioned in Section 1, the SCC is intended to provide a comprehensive estimate of the monetary value of resultant damages from a marginal increase in emissions of CO_2. Thus, it provides an estimate of the amount of the per-unit Pigouvian tax needed to achieve an efficient outcome. Since

2008, the U.S. Government has used estimates of the SCC to evaluate regulations that either positively or negatively impact CO_2 emissions. Integrated assessment models (IAMs) are generally used to derive estimates of the SCC [8,18,41,42]. By predicting future emissions levels based on projected economic growth and future climate responses, IAMs can assess the economic impacts of incremental increases in emissions on different economic sectors. The value of those impacts informs current estimates of the SCC [8,18,41,42].

While using IAMs to estimate the value of the SCC has been shown to provide robust and credible results (see [17,19]), values generated depend on the discount rate applied, the geographical scope and extent and types of the damages considered, and estimates of the future economic growth rate assumed [18,41,42]. As a result, there have been considerable differences in estimated values of the SCC reported in literature in recent years. Figure 4 and Table 1 illustrate the notable disparity observed in the estimated SCC values reported for select scenarios across several different studies. For example, as displayed in Figure 4, values of the SCC for the year 2020 range from as little as $1/t$CO_2$ to over $380/t$CO_2$ across the studies considered.

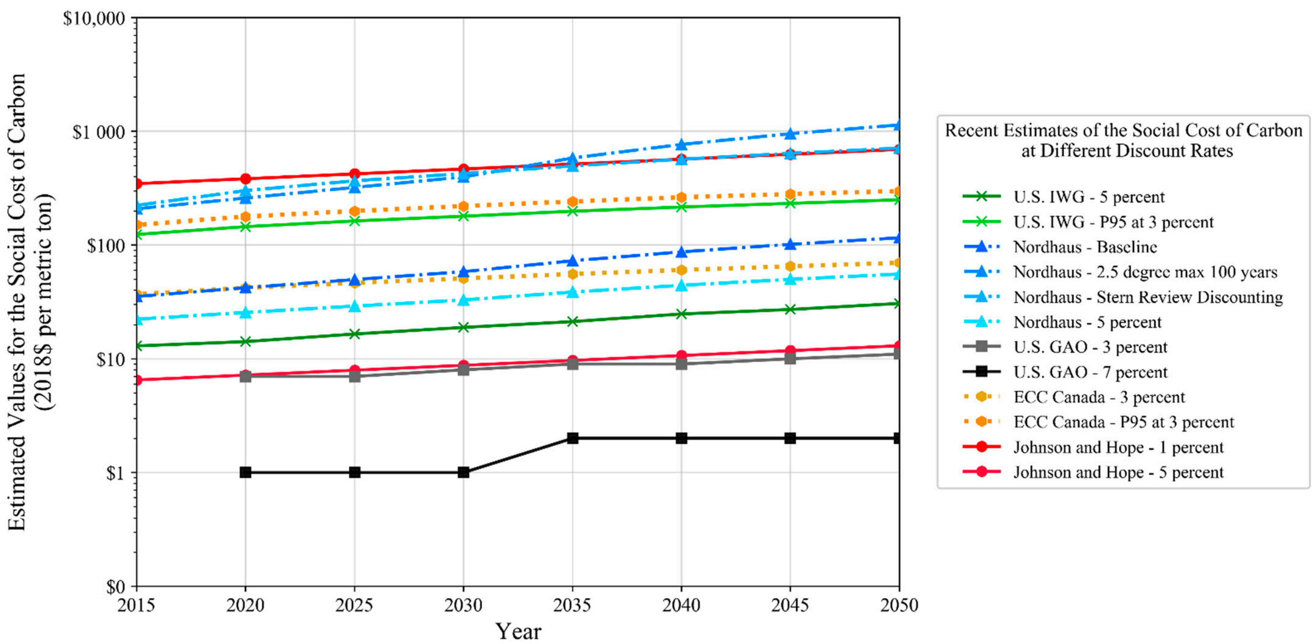

Figure 4. Compilation of estimates of the SCC (in 2018$ USD/tCO_2) from literature. Estimated values are measured in 2018$ and during span years 2015–2050.

Table 1. Recent estimates of the SCC.

Source	Source Year	Discount Rate (Percent)	SCC Value in 2020 (2018 USD/tCO_2$ Emitted)	$ Base Year
U.S. Government Interagency Working Group [43]	2016	2.5 3 3 at P_{95} 5	$73 $50 $145 $14	2007
Nordhaus [17]	2017	4.25 [a] 1.4 [b] 2.5 3 4 5	$41.5 to $42.2 $150 to $259 $301 $158 $99 $46 $26	2010

Table 1. *Cont.*

Source	Source Year	Discount Rate (Percent)	SCC Value in 2020 (2018 USD/tCO_2$ Emitted)	$ Base Year
Johnson and Hope [44]	2012	1 [c] 3 [c] 5 [c]	$383 $30 $7	2007
U.S. Government Accountability Office [45]	2020	3 7	$7 $1	2018
Environment and Climate Change Canada [46]	2016	3	$42 $178	2018 [d]

[a] An average growth-corrected discount rate through 2100 used in the Dynamic Integrated Climate-Economy Integrated Assessment Model estimates. [b] Social discount rate based on the "Ramsey" formula, which includes a term for inherent discounting, called the pure rate of time preference. [c] Johnson and Hope presents SCC values for 2010 only. Projections through 2050 approximated using a 2% inflation rate. [d] Converted from 2012$ Canadian dollars to 2018$ base year U.S. dollars (USD).

Table 1 provides a summary of recent estimated values for the SCC found in the literature since 2016. Values in Table 1 reflect scenarios implemented under a variety of discount rates, focusing primarily on the values for the year 2020.

This digest of estimated values for the SCC from literature is intended to provide a basis from which to inform the range of SCC estimates for considered as part of the scenario analysis described in Section 3.

3. Methods and Scenarios

To examine the effect economizing policies and programs, in conjunction with changes in economic market and policy conditions, have on the decision to invest in CCS, NETL-developed models and resources were modified and then used to evaluate investment decisions under a range of possible CCS network scenarios for two hypothetical, conventional power generation facilities (each with their own specific business-cases). CCS network scenarios considered the decision to invest in CCS under the different economic and market policy conditions coupled with instituted requirement to pay a per-unit tax on unabated emissions of CO_2. The imposed tax reflected estimated values of the SCC.

Altogether, nine scenarios (listed below) were analyzed.

(1) Business as usual (BAU)
(2) BAU with per-unit tax on CO_2 emissions set equal to the SCC (BAU_SCC)
(3) BAU_SCC with CCS and no incentives (CCS_NI)
(4) CCS_NI employing non-refundable Section 45Q tax credits with 12 years of eligibility per current regulations (NR45Q)
(5) NR45Q with Section 45Q tax credit amended to be fully refundable (FR45Q)
(6) FR45Q with Section 45Q tax credit amended for unlimited (equal to 30 years) eligibility (30FR45Q)
(7) 30FR45Q with addition of transportation costs to power plant waived (i.e., free transportation) (30FR45Q_FT)
(8) 30FR45Q_FT with addition of saline storage PISC reduced from 50 years (current U.S. EPA default requirement) to 10 years (30FR45Q_FT_10PISC)
(9) 30FR45Q_FT with addition of storage costs to power plant waived (i.e., free storage) (30FR45Q_FT_FS)

A detailed write-up on the scenarios can be found under the section entitled "Scenario Details" of Appendix A. Appendix A also contains a table simplifying policy-scenario alignment—see Table A5 in Appendix A. Given the uncertainty associated with the true value SCC, scenarios 1 through 9 were evaluated over the range of estimated values for the SCC. Estimates for the SCC were based on recent estimates available in the literature (see Table 1) and ranged from $20/t$CO_2$ to $180/t$CO_2$ (measured in 2018$).

The two hypothetical, conventional U.S. electricity generation facilities considered for evaluation included a 650-MW brownfield subcritical pulverized coal (SubC PC) power plant and a 727-MW brownfield natural gas combined cycle (NGCC) power plant. Brownfield power plants are those not newly built and in need of retrofitting to capture carbon. These two hypothetical, conventional power generation facilities (i.e., coal and natural gas based) were chosen for evaluation given their prominence in contributing to U.S.-based electricity generation. Each plant type was assumed to have a fixed capacity factor and pre-specified average annual after tax rate of return (A/TROR$_{AVG}$), regardless of the scenario being considered, as per NETL costing methodology [47]. Electricity being generated by each power plant was assumed to produce pre-retrofit emissions of CO_2.

Both power plants were assumed to be located in the state of Missouri and assumed to follow state-specific regulations that could influence their production costs (e.g., taxes and delivered fuel charges). For many of the scenarios evaluated, the plants were assumed to be retrofitted with CO_2 capture equipment (i.e., an investment in CCS occurred). Each power plant was evaluated as part of a CCS network scenario that assumed captured CO_2 transported via a dedicated pipeline roughly 328 miles to the nearby Illinois Basin and injected in the Mount Simon sandstone saline aquifer for permanent storage.

The NETL-developed models and resources modified for use to evaluate CCS network scenarios included

- NETL retrofit data (BB4R) (forthcoming 2021–2022) for power plants featured in NETL's publicly available Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity report (Baseline Study) (part of NETL's baseline studies series) to evaluate costs associated with the power plant components [33];
- A modified version of the publicly available 2018 version of the Fossil Energy (FE)/NETL CO_2 Transport Cost Model (CO_2_T_COM) to obtain costs for transporting captured CO_2 from a source to the saline storage site [48];
- A modified version of the publicly available 2017 version of the FE/NETL CO_2 Saline Storage Cost Model (CO_2_S_COM) to determine costs for storing CO_2 in the saline storage formation [49].

The BB4R provided estimates of the nominal incremental cost per MWh of retrofitting the NGCC and SubC PC power plants chosen, respectively, with CO_2 capture equipment over a 30-year operating timeframe. Plants are assumed to operate for 30 years following retrofit for CCS. The CO_2_T_COM provided estimates of the cost to transport the captured CO_2 by pipeline, also over an assumed 30-year operating timeframe. The CO_2_T_COM optimizes the pipeline diameter and number of pumps needed by incorporating major components such as the annual mass of CO_2 captured, the pipeline distance, and the elevation change from a CO_2 source to a storage reservoir location. The CO_2_T_COM user manual describes cost estimation methodologies [48].

The CO_2_S_COM provided estimates of the cost to store the captured CO_2 in a saline reservoir over the life of a CO_2 storage project. The CO_2_S_COM incorporates the costs associated with site selection, characterization, permitting, construction, injection operations, PISC, and site closure. The CO_2_S_COM simulates CO_2 storage project operations in compliance with U.S. EPA Underground Injection Control (UIC) Class VI regulations [50] and Subpart RR of the Greenhouse Gas Reporting Rule [51]. More detail on these resources and tools as well as aspects of the capture, transport, and storage items can be found in the sections titled "Details Behind the Capture Component of the CCS Network," "Details Behind the Transport Component of the CCS Network," and "Details Behind the Storage Component of the CCS Network" in Appendix A.

The methodology employed aggregated finances from the brownfield plants and each CCS network scenario component (i.e., CO_2 capture at the plant, transport, and storage) to solve for the LCOE (in 2018 $/MWh) required by each power plant to meet its specified A/TROR$_{AVG}$ based on the assumptions of the policy scenario employed. Estimated values for the LCOE are based on the resulting financial conditions for each power plant given a per-unit tax on unabated emissions of CO_2 set equal to estimated values for the SCC being assumed, the costs associated with retrofitting and operating CO_2 management via CCS, as well as any recompence from the policies assumed in each scenario.

Each plant type's BAU LCOE is inclusive of fixed, variable, and fuel costs. Additionally, each plant is assumed to have paid off capital-related expense and debt from operations prior to retrofit. To estimate the LCOE (in 2018 $/MWh), the revenue of each power plant in 2018 (which returns A/$TROR_{AVG}$ equal to 7.84%) was divided by the net electricity output being produced under the scenario. More information on how the LCOE for each plant was calculated can be found under the "Scenario Analysis Aggregating Finances Across Components of the CCS Network" section in Appendix A.

The LCOE for each plant was used as the cost metric from which cost comparison across modeling scenarios were based. LCOE estimates quantified under the variety of CCS policy and SCC configurations explored were evaluated against the corresponding LCOEs estimated under the BAU, non-abatement scenario, wherein only a per-unit-imposed tax equal to estimated values of SCC was assumed. The comparative analyses provide indication of either (1) the financial gap that remains for CCS to be considered the cost-minimizing choice for each power plant type considered under different CCS-based incentives or (2) the required CCS policy/SCC value combinations that may promote adoption of CCS as a CO_2 management strategy for the two specific source types evaluated.

4. Results and Discussion

Tabular results for the LCOE estimation for the 650-MW SubC PC and 727-MW NGCC units across scenarios at the discrete values of SCC modeled are provided in Appendix A and are shown graphically in Figure 5 (via extrapolation between modeling points). As previously mentioned, all costs are in nominal 2018$. The lines in each chart of Figure 5 represent the range of LCOE estimates generated based on each policy scenario evaluated, under different estimated values for the SCC. The availability of additionally beneficial CCS policy conditions drives the resulting LCOE lower in each instance for both plants. However, when CCS retrofits occur, no policy conditions resulted in either plant's LCOE dropping below the unabated BAU level. Pairings of policy conditions/SCC tax values favorable to CCS deployment for the two plants modeled are highlighted in blue. CCS favorability occurs when the resulting LCOE is at or below the corresponding LCOE in the BAU_SCC scenario.

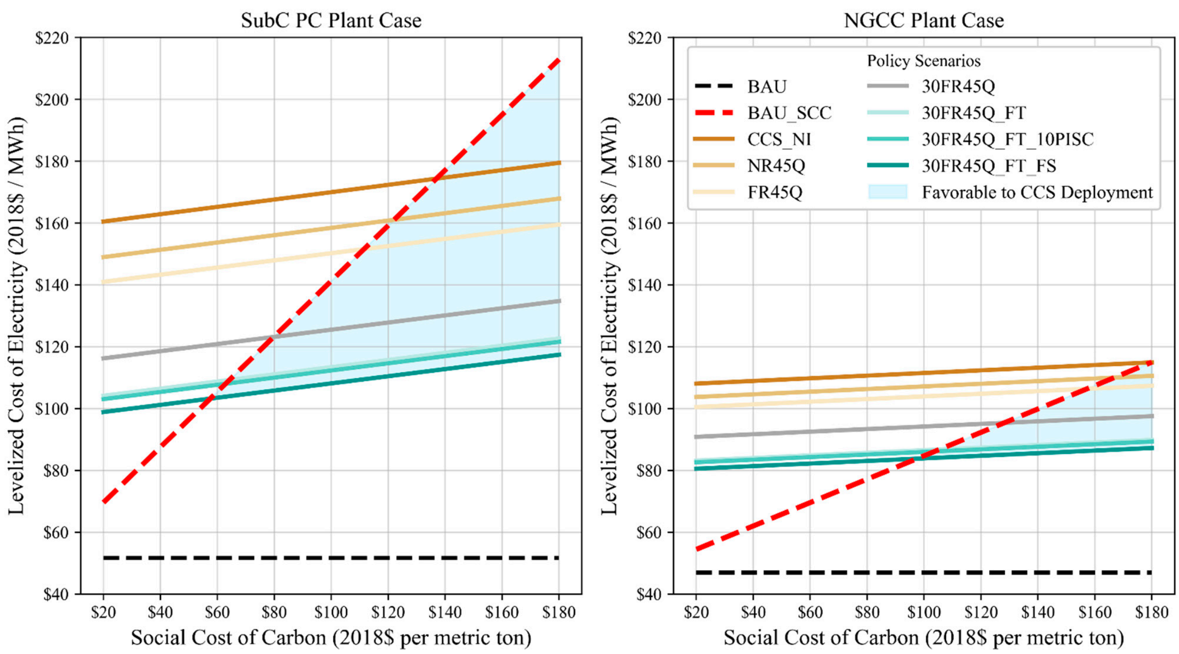

Figure 5. SCC vs. LCOE policy chart for modeled SubC PC plant (**left**) and NGCC plant (**right**).

In general, the SubC PC plant is incentivized to implement CCS under much lower assumed values for the SCC as a per-unit tax on emissions relative to the NGCC plant modeled, likely because of the differences in CO_2 emissions rate per unit of electricity generated (NGCC has less CO_2 emissions per MWh; therefore, its LCOE is less negatively affected by SCC increases). Analysis of the slopes of lines in Figure 5 reinforces this concept. For the BAU scenarios, being subject to a per-unit tax set equal to estimated values of the SCC on unabated emissions (dashed red lines; BAU_SCC), each \$1.00/tCO_2 emissions being charged adds \$0.90/MWh to the LCOE of the 650-MW SubC PC plant modeled and \$0.38/MWh to the LCOE of the 727-MW NGCC plant.

The SubC PC to NGCC ratio of additions to the LCOE as a result of the per-unit tax on emissions being charged (\$0.90/\$0.38 = 2.37) is equal to the ratio of the two plants' pre-retrofit annual CO_2 emissions per pre-retrofit nameplate capacity (NC) as described in Equation (1).

$$\frac{SubC\ PC\ CO_2\ Per\ Year}{SubC\ PC\ NC\ PreCCS} \Big/ \frac{NGCC\ CO_2\ Per\ Year}{NGCC\ NC\ PreCCS} = \frac{3.923\ MtCO_2}{650\ MW} \Big/ \frac{1.852\ MtCO_2}{727\ MW} = 2.37. \quad (1)$$

Equation (1) suggests a relationship between the impact of the assumed value for the SCC and a plant's pre-retrofit NC and CO_2 emissions rate.

The post-retrofit CCS scenarios subject to a per-unit tax on remaining unabated emissions of CO_2 set equal to estimated values of the SCC (solid lines in Figure 5) show that for each \$1.00/tCO_2 emissions being charged, the LCOE increases by \$0.119/MWh for the SubC PC plant, and by \$0.043/MWh for the NGCC plant. The ratio of these two additions to the LCOE (\$0.119/\$0.043 = 2.78) is almost equal to the ratio of the two plants' pre-retrofit CO_2 emissions rate per post-retrofit NC as described in Equation (2).

$$\frac{SubC\ PC\ CO_2\ Per\ Year}{SubC\ PC\ NC\ PostCCS} \Big/ \frac{NGCC\ CO_2\ Per\ Year}{NGCC\ NC\ PostCCS} = \frac{3.923\ MtCO_2}{491\ MW} \Big/ \frac{1.852\ MtCO_2}{641\ MW} = 2.77. \quad (2)$$

Equation (2) suggests a relationship between the impact of the SCC with CCS and a plant's post-retrofit NC and CO_2 emissions rate. For retrofitting and implementing CCS to be considered the cost-minimizing choice for the power plant types considered, the resulting LCOE from a per-unit tax, set equal to estimated values of the SCC being imposed on 100% of the non-captured CO_2 emissions generated must be higher than the resulting LCOE under conditions with an additive combination of retrofitted an implemented CCS, and a per-unit tax on emissions set equal to the SCC being imposed on remaining non-captured CO_2 (10% in this case)—while leveraging CCS-favorable policy [52].

Table 2 summarizes the points of intersection (from Figure 5) as a function of the assumed value for the SCC for each plant type considered between the BAU_SCC scenario and other scenarios evaluated.

Table 2. Transition points to economically efficient CCS implementation given prevailing SCC value and policy conditions.

Policy Scenario	SubC PC Plant Case		NGCC Plant Case	
	SCC (2018 \$/tCO_2)	LCOE (2018 \$/MWh)	SCC (2018 \$/tCO_2)	LCOE (2018 \$/MWh)
CCS_NI	137.00	174.35	180.00	114.91
NR45Q	123.00	161.14	167.00	110.00
FR45Q	112.00	151.61	158.00	106.40
30FR45Q	80.00	123.16	129.00	95.39
30FR45Q_FT	65.00	109.32	106.00	86.76
30FR45Q_FT_10PISC	63.00	108.01	104.00	86.11
30FR45Q_FT_FS	58.00	103.25	98.00	83.79

The first column in Table 2 lists the policy scenarios that were compared against BAU_SCC for both plant types. The reported SCC and LCOE values under each plant type represent the results from the points of intersection for each scenario (i.e., the point where the estimated LCOE for the BAU_SCC is equal to the LCOE for each of the other respective policy conditions). These intersections represent the point at which economically efficient operational conditions for each plant may transition from fully unabated CO_2 emissions toward retrofit implementation for 90% CCS given (1) that the assumed CCS-favorable policy conditions would be in place, (2) a per-unit tax on emissions is being charged, and (3) the demand exists for energy at the specified LCOE price point.

The values in Table 2 (and similarly in Figure 5) show that under current non-refundable Section 45Q policy (NR45Q scenario), the SCC must exceed \$123/tCO_2 emitted for CCS implementation to be considered the cost-minimizing choice for the SubC PC plant modeled; at that point, the LCOE would exceed \$161.14/MWh. Similarly, the SCC must exceed \$167/tCO_2 emitted for CCS to be considered the cost-minimizing choice at the NGCC plant modeled; the LCOE would exceed \$110.00/MWh. In the absence of the current Section 45Q, CCS is still considered the cost-minimizing choice for the NGCC and SubC PC plants modeled when SCC per-unit tax exceeds \$180/tCO_2 and \$137/tCO_2 emitted, respectively.

Results outlined in Figure 5 and Table 2 are indexed to assume a CO_2 capture rate of 90%. Under high rates of carbon capture (e.g., >90%), the availability of additionally beneficial CCS policy conditions (e.g., Section 45Q) will further reduce each plants LCOE (i.e., curves will shift to the left) effectively lowering the estimated values of the SCC needed for CCS to be considered the cost-minimizing choice. The data in Table 2 also highlight two instances where relatively substantial gaps exist between the policy scenario's SCC and LCOE intersection points.

These gaps first occur between the fully refundable Section 45Q scenario (FR45Q) and the fully refundable Section 45Q with no sunset scenario (30FR45Q) (\$32/tCO_2 for SCC and \$28.45/MWh for SubC PC and \$29/tCO_2 for SCC and \$11.01/MWh for NGCC). The second occurs between the 30FR45Q scenario and the fully refundable Section 45Q with no sunset and free transportation (30FR45Q_FT) scenario (\$15/tCO_2 for SCC and \$13.84/MWh for SubC PC and \$23/tCO_2 for SCC and \$8.63/MWh for NGCC).

These larger gaps in price points relative to the separation between other scenarios suggest that a potentially considerable policy-based benefit may exist in the forms of (1) removing Section 45Q tax credit sunsets, thereby extending tax credits from 12 years of eligibility to (effectively) 30 years of eligibility, and (2) subsidizing the transport of CO_2 (in combination with an extended Section 45Q eligibility period) from sources to sinks. The value obtained from these policies will likely scale according to the volumes of CO_2 captured, transported, and stored, the distance from CO_2 source to sink, and the prevailing terrain/change in altitude expected over that distance.

5. Conclusions

Large-scale deployment of CCS can help sustain reliable supplies of electricity to meet energy demands, while simultaneously contributing towards the goals necessary to achieve decarbonization [53,54]. While CCS is considered to be technically feasible, current economic and market policy conditions undoubtedly play a role in the financial feasibility of retrofitting existing power generation facilities with CCS. While some policy support for investment in CCS is available (e.g., Section 45Q) an analysis of the influence of and changes in available policy support, in conjunction with changes in market and economic policy conditions known to influence CCS investments, remains a question to be answered in literature.

Using scenario analysis, this paper represents an attempt to answer such a question. Scenarios consider changes in already established policies for CCS, including removing the 12-year cap on eligibility for the Section 45Q tax credit, making Section 45Q tax credits fully refundable, subsidizing transportation infrastructure (similar to the recently introduced

Storing CO_2 and Lowering Emissions Act [55]), reducing the duration of storage PISC, subsidizing storage, and establishing a per-unit tax on unabated emissions of CO_2 set equal to a range of estimated values for the SCC. Given public policy and decision makers' reliance on estimates of the SCC to quantify the costs and benefits of decisions that could alter the amount of CO_2 present in the atmosphere, the SCC is an important consideration when discussing the potential benefits of CCS.

Scenario results suggest that if the SCC is more than \$123/tCO_2, then investing in CCS to abate emissions and paying a per-unit tax on any remaining emissions (10% of emissions assumed to remain unabated) represents the cost-minimizing choice for the SubC PC plant type considered under current Section 45Q tax credit policy. If the SCC is more than \$167/tCO_2, then investing in CCS to abate emissions and paying a per-unit tax on any remaining emissions (10% of emissions assumed to remain unabated) represents the cost-minimizing choice for the NGCC plant type considered, again under current Section 45Q tax credit policy.

The availability of additionally beneficial CCS policy conditions considered drives the resulting SCC needed to make CCS the cost-minimizing choice, given investing in CCS to abate emissions and paying a per-unit tax on any remaining emissions (10% of emissions assumed to remain unabated) to as low as \$58/tCO_2 emitted and \$98/tCO_2 emitted, for SubC PC and NGCC plants, respectively. Together results suggest that if a per-unit tax on emissions was in place and the amount of the per-unit tax was set equal to the estimated value of the SCC, then even at lower estimated values for the SCC, beneficial CCS policy conditions (e.g., the option for free transportation and storage) play a critical role in reducing the amount of CO_2 emissions that enter the atmosphere via CCS from the types of CO_2 sources evaluated. Otherwise, only at higher estimated values for the SCC, will the establishment of a per-unit tax on emissions, incentivize investment in CCS. These implications are contingent on demand for energy at the specified LCOE price points given that the ranges of SCC are evaluated.

From a public policy perspective, since the general public benefits from CO_2 being captured, stored, and prevented from entering the atmosphere, there is economic justification for public policies targeted at providing economic incentives for investments in CCS technology [4]. Furthermore, since estimated values of the SCC span many orders of magnitude and there continues to be much disagreement on the true value of the SCC, if decarbonization is to remain a key policy objective, then policy support for CCS should be given further consideration in discussions of strategies to reduce CO_2 emissions. As an emerging technology, CCS could demonstrably improve progress towards an alternative energy future while removing the guess work of estimation of the value of damages from CO_2.

In this study, our analytical approach for estimating LCOE for brownfield power plants was limited to the assumption that each plant had paid off capital-related expenses and debt from operations prior to retrofit. LCOE estimates could potentially scale higher if portions of capital costs were included in the financial modeling. Another limitation is given that estimates of the SCC are notably influenced by the unique perspectives on climate change impact valuation inherent to the entities generating SCC appraisals, yielding a large disparity in estimated values for the SCC (see Table 1 and presented in Figure 5); it is difficult to ascertain if establishment of a per-unit tax on emissions equal to the SCC would ever occur in practice and, with absolute certainty, to understand how power plants would respond. This would also include consideration of other decarbonization strategies such as CCS with EOR or utilization versus saline storage or investment towards combustion efficiency.

Depending on the referenced SCC value, different stakeholder groups may reach dissimilar conclusions when considering suitable mitigation strategies [56]. For example, the estimates of SCC reported by the U.S. Government Accountability Office in 2020 (\$3/tCO_2 and \$7/tCO_2) would likely fail to prompt CCS retrofitting for the two plants evaluated in this analysis; regardless of the multitude of policy incentives or subsidies available.

However, higher magnitude SCCs approaching those determined by Nordhaus (2017) [17] (\$301/tCO_2) and Johnson and Hope (2012) [44] (\$422/tCO_2) under lower discounting conditions (1–1.4%) would likely encourage CCS retrofitting for the plant types evaluated, even in the absence of the current Section 45Q tax credit. Nevertheless, quantifying how an incentive-based policy such as the payment of a per-unit tax on emissions set equal to the SCC will influence the decisions to invest in CCS is of critical importance.

Furthermore, depending on their risk-preferences, if changes in the value of the per-unit tax are expected, which, based on the range of estimated values available for the SCC to date, may be possible, then some power plant operators may choose to pay a short-term higher tax for all emissions rather than invest in CCS, in expectation of a lower tax rate being assigned in the future.

Future work to identify an accurate estimate of the true SCC should consider this dilemma in advancing efforts to achieve decarbonization and determining the social benefits that could be achieved. In addition, if the aim of future research is to estimate the benefits of programs or policies that incentivize CCS, then deriving elasticity estimates for the relationship between increases in a plant's capture rate and the required per-unit tax amount needed for CCS to be the cost-minimizing choice could provide some evidence of supported benefits and would be a natural extension of this research.

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Appendix A. Additional Details on Study Components

This appendix provides more details on methodology, key parameters used in the models for obtaining costs for each carbon capture and storage (CCS) value chain component (i.e., carbon dioxide (CO_2) capture, CO_2 transport, and CO_2 storage), key assumptions, policy scenarios, and additional scenario results. It is important to note that all costs in this study are in nominal 2018 dollars (2018$).

Appendix A.1. Methodology Steps

Several steps were accomplished to obtain estimates for the levelized cost of electricity (LCOE) needed to meet the specified annual average after tax rate of return (A/TROR$_{AVG}$) under each policy scenario. Steps are outlined below.

(1) Utilized National Energy Technology Laboratory (NETL)-developed resources and models to evaluate CCS network economics:
   a. NETL retrofit data (BB4R) (forthcoming 2021–2022) for power plants featured in the NETL's publicly available Cost and Performance Baseline for Fossil Energy Plants, Volume 1: Bituminous Coal and Natural Gas to Electricity report (Baseline Study) (part of NETL's baseline studies series) to evaluate costs associated with the power plant components [33].
   b. A modified version of the publicly available 2018 version of the Fossil Energy (FE)/NETL CO_2 Transport Cost Model (CO_2_T_COM) to obtain costs for transporting captured CO_2 from a source to the saline storage site [48].
   c. A modified version of the publicly available 2017 version of the FE/NETL CO_2 Saline Storage Cost Model (CO_2_S_COM) to determine costs for storing CO_2 in the saline storage formation [49].

(2) Developed business as usual, social cost of carbon (SCC), and various policy scenarios to determine the LCOE for each scenario when A/TRORAVG is equal to 7.84%.

(3) Employed aggregated finances from the power plants and CCS network components (i.e., CO_2 capture, transport, and storage) mentioned above to solve for the LCOE (in 2018$ per megawatt-hour (2018 $/MWh)) required by each power plant type considered to meet the specified A/TRORAVG under each policy scenario. The LCOEs calculated were based on the resulting financial conditions for each plant given the imposed SCC-based per-unit tax, costs associated with retrofitting and operating CO_2 management via CCS, as well as any recompence from the policies assumed in each scenario. SCC values in 2018$ ranged from $20 to $180 per metric ton of CO_2 emitted (2018$/t$CO_2$) to the atmosphere, for each plant, for each scenario.

Appendix A.2. Details behind the Capture Component of the CCS Network

Plant specifications for the two power plant types, sub-critical pulverized coal (SubC PC) and natural gas combined cycle (NGCC), selected for evaluating the capture portion of the CCS network value chain were taken from the Baseline Study, which provides estimates for the cost and performance of newly built (i.e., greenfield) combustion- and gasification-based power plants with and without CO_2 capture. Because this study examined existing (i.e., brownfield) non-capture plants being retrofitted with capture equipment, unique pre-retrofit and post-retrofit inputs were derived using the greenfield non-capture SubC PC and NGCC power plants within the Baseline Study and converting them to brownfield plants then using associated retrofit data in BB4R.

The LCOE of each brownfield plant was derived from its fixed, variable, and fuel costs (without capital). LCOE estimates for the retrofitted plant only included capital from the retrofit, as well as fixed, variable, and fuel costs from both the retrofit and the existing brownfield plant. Therefore, the LCOE of the capture portion only (incremental cost of electricity from carbon capture equipment (CCE) was estimated by subtracting each retrofit plant's LCOE from its associated greenfield plant's LCOE minus the associated greenfield plant's capital costs.

Key specifications and results associated with each of the power plants from the Baseline Study and BB4R are shown in Table A1. The tax equity partnership allocation of tax equity investment to retrofit power plant is the after-tax revenue generated from Section 45Q tax credits and is used in the CCS with non-refundable Section 45Q tax incentive (sunset) (NR45Q) scenario, which is described in more detail within the Scenario Details section below.

Table A1. Key specifications and results from the Baseline Study and BB4R used in the study.

Parameter Type	Specification or Result	Unit	SubC PC Plant	NGCC Plant
Pre-retrofit	Net plant output	MW	650	727
	Capacity factor	%	85	
	Net output electricity production rate	MWh/yr.	4,839,602	5,409,876
	LCOE	2018 $/MWh	51.64	46.86
	Fuel (delivered to Midwest)	Type	Illinois No. 6 coal	Natural gas
	Fuel cost	2018 $/MMBtu	6.2077	3.2449
	CO_2 atmospheric emissions rate	tCO_2/yr.	3,922,661	1,852,300
Post-retrofit	Retrofit CO_2 capture (separation) technology	None	Cansolv (amine based)	
	Nameplate capacity	MW	491	641
	Net output electricity production rate	MWh/yr.	3,654,273	4,776,222
	CO_2 captured	%	90	
	CO_2 capture rate	tCO_2/yr.	3,530,395	1,677,070
	CO_2 emissions rate	tCO_2/yr.	392,226	185,230
Financial	After tax rate of return (i.e., cost of equity)	%	7.84	
	Cost of debt	%	2.94	
	Debt/equity ratio	Dimensionless	55/45	
	Escalation/inflation rate	%	2	
	Federal income tax rate	%	21	
	State and local income tax rate	%	6	
	Tax equity partnership allocation of tax equity investment to retrofit power plant	After tax Revenue/$45Q	0.54	
	Incremental cost of electricity generation (i.e., capture cost)	2018 $/MWh	65.03	39.39
		2018 $/$tCO_2$	67.31	112.85

Some key assumptions associated with the power plants included:

- Power plants are brownfield pre-retrofit with all capital costs paid off;
- Developer/owner is investor-owned utility;
- Retrofit capture equipment would capture 90% of CO_2 (i.e., 10% of pre-retrofit emissions are still emitted to the atmosphere post-retrofit);
- Retrofitted capital costs have 3-year capital expenditure period; and
- Additionally, 7.84% specified $A/TROR_{AVG}$ based on NETL methodology as presented within NETL's Quality Guidelines for Energy Systems Studies: Cost Estimation Methodology for NETL Assessments of Power Plant Performance [47].

Appendix A.3. Details behind the Transport Component of the CCS Network

For the study, a modified version of the publicly available 2018 version of CO_2_T_COM was used to obtain costs for transporting CO_2 via a dedicated pipeline [48]. Certain parameters were changed from their default values (those values already within CO_2_T_COM on NETL's website) in the model. The key parameters changed, as well as key outputs from the model runs, are highlighted in Table A2. Please note that the publicly available version of the model has a single escalation rate that escalates costs from the base year (2011) to the first year of the project. To be consistent with costs in NETL's energy system studies (which are currently in real 2018$), CO_2_T_COM was modified to allow two escalation rates, so costs can be modeled in real or nominal dollars; hence, the two escalation rates shown in Table A2. The first-year break-even cost under key outputs in Table A2 is used to calculate the incremental LCOEs.

Table A2. Critical parameters and key outputs for CO_2_T_COM runs in the study.

Parameter Type		Parameter	Unit	SubC PC	NGCC
Inputs	Schedule	Project start year	year	2018	
	Design	Pipeline length	mi	328	
		Capacity factor	%	85	
		Elevation change from source to sink	ft	−390	
	Operations	CO_2 transportation rate	tCO_2/year	3,530,395	1,677,070
	Financial	After tax rate of return (i.e., cost of equity)	%	13	
		Cost of debt	%	6	
		Debt/equity ratio	Dimensionless	60/40	
		Escalation rate from start 2011 to 2018	%	2.2	
		Escalation rate beyond 2018	%	2	
		Federal income tax rate	%	21	
		State and local income tax rate	%	6	
Outputs		Optimal pipe diameter	in	12	8
		Optimal number of pumps	Number	5	10
		First-year break-even transportation cost	2018 $/$tCO_2$	11.62	20.37

Appendix A.4. Details behind the Storage Component of the CCS Network

For the study, a modified version of the publicly available 2017 version of CO_2_S_COM was used to obtain the costs of storing CO_2 in the selected saline reservoir, Mount Simon 3 [49]. Mount Simon 3's geologic characteristics, per CO_2_S_COM's geologic database, are provided in Table A3.

Table A3. Geologic characteristics for the Mount Simon 3 reservoir in CO_2_S_COM.

Geologic Storage Reservoir Parameter	Unit	Value
Areal extent	mi^2	20,633
Depth	ft	4270
Net thickness of reservoir	ft	1000
Porosity	%	12
Permeability	mD	125
Storage coefficient (dome)	%	15.28

Modifications to the model were completed to perform certain scenarios for the scenario analysis. Outcomes of these modifications are described as follows, with more details included in the Scenario Details section:

- NR45Q scenario: Calculates the maximum amount of non-refundable general business credits that could be used to lower the federal tax liability for each of the 30 operating years. The amount of the Section 45Q tax credits needed in the first 12 years (assuming transfer from the CCE operator) to be used in the first 12 years plus 18 more using carry-forward is also calculated. The federal tax liability is reduced accordingly to calculate the first-year break-even cost in 2018$/t$CO_2$.

- CCS with fully refundable Section 45Q tax incentive (sunset) (FR45Q) scenario: Variants allow the CCS equipment owner (the power plant) to monetize all Section 45Q tax credits; therefore, no transfer of Section 45Q tax credits to the storage operator, nor reduced storage cost associated with Section 45Q tax credits, is assessed for these scenarios.
- CCS with fully refundable 45Q tax incentive (no sunset) with free transportation and 10-year post-injection site care (PISC) (30FR45Q_FT_10PISC) scenario: Assesses the impact of 10-year PISC on the first-year break-even cost instead of 50-year PISC, by changing the PISC duration input within the model.

Certain parameters were changed from their default values (those values are already within CO_2_S_COM on NETL's website) in the model. The key parameters changed, as well as key outputs from the model runs, are highlighted in Table A4. Please note that the publicly available version of the model has a single escalation rate that escalates costs from the base year (2008) to the first year of the project. To be consistent with costs in NETL's energy system studies (which are currently in real 2018$), CO_2_S_COM was modified to allow two escalation rates, so costs can be modeled in real or nominal dollars; hence, the two escalation rates are shown in Table A4. The first-year break-even cost under key outputs in Table A4 was used to calculate the incremental LCOEs.

Table A4. Critical parameters and key outputs for CO_2_S_COM runs in the study.

Parameter Type		Parameter	Unit	SubC PC	NGCC
Inputs	Schedule	Project start year	year	2018	
		Site screening duration	year	0.5	
		Site selection and site characterization duration	year	0.5	
		Theoretical policy PISC option	year	10	
	Geology	Saline storage reservoir	Reservoir name	Mount Simon 3	
		Saline storage structure setting	Description	Dome	
	Operations	Multiplier for annual to maximum daily rate of CO_2 injection (represents 85% capacity factor)	Dimensionless	1.18	
		CO_2 injection rate (storage rate)	tCO_2/year	3,530,395	1,677,070
	Financial	After tax rate of return (i.e., cost of equity)	%	13	
		Cost of debt	%	6	
		Debt/equity ratio	Ratio	60/40	
		Escalation rate from 2008 to 2018	%	1.3	
		Escalation rate beyond 2018	%	2	
		Federal income tax rate	%	21	
		State and local income tax rate	%	6	
Outputs		First-year break-even cost for all policies except NR45Q and 10-year PISC	2018 $/t$CO_2$	5.05	7.01
		First-year break-even cost for NR45Q	2018 $/t$CO_2$	4.97	6.90
		Total Section 45Q transferred from source to storage operator	2018 MM $/12 years	6.82	6.46
		First-year break-even cost for 10-year PISC	2018 $/t$CO_2$	4.01	5.50

Appendix A.5. Scenario Details

Nine scenarios are modeled for the two power plants to determine the incremental LCOE (2018 $/MWh), based on pre-tax revenue, costs, taxes, tax credits, and after-tax revenue (if tax equity is involved). Costs are derived using the previously discussed methodology. Tax treatment is based on Internal Revenue Service and Treasury guidance and regulations, as well as theoretical assumptions (for theoretical policies). A detailed write-up follows on each of the scenarios, and scenario-policy alignment is presented in a simplified format in Table A5.

- Business as usual (BAU): Non-capture plant configuration, where no penalty for CO_2 emissions exists; LCOE equals the baseline market price for a brownfield power plant.
- Per-unit tax set equal to the SCC (BAU_SCC): Non-capture plant configuration that pays a per-unit tax set equal to the SCC for each tCO_2 emitted into the atmosphere (100% of BAU emissions).
- CCS with no market incentive (CCS_NI): Plants are retrofitted with CCE that captures 90% of BAU emissions, pays a per-unit tax set equal to the SCC for each tCO_2 emitted into the atmosphere (10% of BAU's emissions), and bares all of the costs associated with installing the capture equipment, transporting, and storing the captured CO_2.
- CCS with non-refundable Section 45Q tax incentive (sunset) (NR45Q): Comparable to CCS_NI, but the costs associated with installing the equipment, transporting, and storing the captured CO_2 are partially offset by the Section 45Q tax incentive. Plants claim and monetize the Section 45Q tax incentive for 12 years of operation following the installation of their CCE equipment. Plants transfer the maximum allowable amount of the incentive they can in exchange for reduced CO_2 storage costs and transfer the remaining amount to tax equity investors through a tax equity partnership, in exchange for \$0.54 after-tax revenue for each \$1 of Section 45Q tax credit allocated. Based on a Sargent & Lundy scoping study for the San Juan Generating Station Carbon Capture Retrofit, a 10% discount rate for tax equity financing is assumed [57]. To achieve $A/TROR_{AVG}$ of 7.84% for 30 operating years, the power plants operate above 7.84% $A/TROR_{AVG}$ for each of the first 12 operating years of Section 45Q eligibility, and operate below 7.84% for operating years 13 through 30.
- CCS with fully refundable Section 45Q tax incentive (sunset) (FR45Q): Comparable to NR45Q, but the costs associated with installing the equipment, transporting, and storing the captured CO_2 are partially offset by the Section 45Q tax incentive amended to be fully refundable. Plants claim and monetize the Section 45Q tax incentive for 12 years of operation following the installation of their CCE equipment. Plants do not transfer part of the incentive to a storage system operator or tax equity investor. Instead, the tax incentive reduces the plants' federal tax liability to below zero and results in a tax refund set equal to the after-tax revenue being received by the plant.
- CCS with fully refundable Section 45Q tax incentive (no sunset) (30FR45Q): Comparable to FR45Q, except the plants claim and monetize a fully refundable Section 45Q tax incentive for a 30-year operating timeframe rather than only 12 years.
- CCS with fully refundable Section 45Q tax incentive (no sunset) with free transportation (30FR45Q_FT): Comparable to 30FR45Q, except the power plant has access to zero-cost CO_2 pipeline(s) to transport captured CO_2 to a saline storage site during its 30-year operating timeframe.
- CCS with fully refundable Section 45Q tax incentive (no sunset) with free transportation and 10-year PISC (30FR45Q_FT_10PISC): Comparable to 30FR45Q_FT, except the power plant must pay to store its captured CO_2 at a saline storage site that is subject to a 10-year PISC period, as opposed to a 50-year PISC as a default currently under the United States Environmental Protection Agency's Underground Injection Control Class VI injection well regulations. The result of which may provide substantial cost savings [58].
- CCS with fully refundable Section 45Q tax incentive (no sunset) with free transportation and free storage (30FR45Q_FT_FS): Comparable to 30FR45Q_FT, except the power plant can also store its captured CO_2 for free over its 30-year operating timeframe and assumes no financial commitment toward PISC.

Table A5. Scenarios described by policy in place.

		Scenario Description by Policy ("X" Denotes POLICIES in Place)								
Scenario	**Scenario Name**	**SCC Per-Unit Tax**	**% of Pre-Retrofit Emissions Subject to SCC**	**CCS**	**NR45Q (12-yr Sunset)**	**FR45Q (12-yr Sunset)**	**FR45Q (No Sunset)**	**Free Transport**	**10-yr PISC at Storage**	**Free Storage**
BAU	Business as usual (baseline for context)		0							
BAU_SCC	BAU + social cost of carbon (baseline for finance gap calculations)	X	100							
CCS_NI	BAU_SCC + CCS (no incentives)	X	10	X						
NR45Q	BAU_SCC + CCS + non-refundable 45Q (12-year sunset)	X	10	X	X					
FR45Q	BAU_SCC + CCS + fully refundable 45Q (12-year sunset)	X	10	X		X				
30FR45Q	FR45Q with no sunset	X	10	X			X			
30FR45Q_FT	30FR45Q + free transportation	X	10	X			X	X		
30FR45Q_FT_10PISC	30FR45Q_FT + storage with 10-year PISC duration	X	10	X			X	X	X	
30FR45Q_FT_FS	30FR45Q_FT + free storage	X	10	X			X	X		X

Scenarios 2 through 9 include a SCC per-unit tax, which is equal to \$20, \$40, \$60, \$80, \$100, \$120, \$140, \$160, and \$180 (2018 \$/tCO_2 emitted to the atmosphere), to assess the impact of the SCC on the resulting LCOE. Scenarios 3 through 9 include the costs of retrofitting the plant for carbon capture, as well as CO_2 transport and storage costs. For scenarios 3 through 9, as a result of the decision to install CCE, the plants reduce their CO_2 emissions by 90%. The remaining 10% of emissions is subject to a per-unit tax equal to the SCC. A financial gap is calculated as the scenario's LCOE (Scenario 2's LCOE shown in Tables A6 and A7). Scenarios 4 through 9 include various policies or policy combinations, to assess the impact of policy on LCOE.

Appendix A.6. Scenario Analysis Aggregating Finances across Components of the CCS Network

Aggregated finances from the brownfield plant and each CCS network component (i.e., CO_2 capture at the plant, transport, and storage) were used to solve for the LCOE (in 2018\$/MWh) required by each considered power plant type to meet its specified $A/TROR_{AVG}$ under the assumptions of each policy scenario. All financial line items were calculated, including revenue needed to get $A/TROR_{AVG}$ of 7.84%, for the first year. Then, those costs were escalated for the next 29 years but $A/TROR_{AVG}$ of 7.84% still had to be met. The LCOE (in 2018 \$/MWh) was determined by taking the revenues for year 2018 (which returns $A/TROR_{AVG}$ equal to 7.84%) and dividing it by the scenario's net electricity output.

Appendix A.7. Results from Aggregation of Costs across the CCS Network

LCOEs for each plant type, scenario, and SCC input are tabulated as results. LCOE is plotted against SCC input, for each scenario, by plant. When LCOEs of scenarios 3 through 9 are less than their corresponding LCOEs of Scenario 2 (for a given SCC value), it is advantageous for the plant (with those policy configurations) to retrofit and engage in CCS. When LCOEs of scenarios 3 through 9 are greater than their corresponding LCOEs of Scenario 2 (for a given SCC value), it is advantageous for that plant (with those policy configurations) to not engage in CCS and continue unabated atmospheric emissions.

Tables A6 and A7 show the LCOE results from aggregating costs across the CCS network for SubC PC and NGCC plants, respectively, over a \$20–180/tCO_2-emitted SCC per-unit tax range. When the LCOE for a given SCC and policy scenario pairing (for scenarios 3–9) is less than its Scenario 2 LCOE for that SCC, its finance gap (the difference between the LCOEs, shown in Tables A8 and A9) is negative, and deployment of CCS is the cheaper option (highlighted in light blue in Tables A6–A9).

Table A6. LCOE (2018$/MWh) for 650-MW SubC PC scenarios.

Scenario	SCC (2018 \$/tCO_2 Emitted)								
	20	40	60	80	100	120	140	160	180
	LCOE (2018 \$/MWh)								
BAU	51.64	51.64	51.64	51.64	51.64	51.64	51.64	51.64	51.64
BAU_SCC	69.56	87.48	105.41	123.33	141.25	159.17	177.09	195.02	212.94
CCS_NI	160.46	162.84	165.21	167.59	169.96	172.33	174.71	177.08	179.45
NR45Q	148.96	151.32	153.69	156.05	158.42	160.78	163.15	165.51	167.88
FR45Q	140.95	143.27	145.58	147.90	150.21	152.53	154.84	157.16	159.47
30FR45Q	116.22	118.53	120.85	123.16	125.48	127.79	130.11	132.42	134.74
30FR45Q_FT	104.11	106.43	108.74	111.06	113.37	115.69	118.00	120.32	122.63
30FR45Q_FT_10PISC	103.03	105.34	107.66	109.97	112.29	114.60	116.92	119.23	121.55
30FR45Q_FT_FS	98.85	101.16	103.48	105.79	108.11	110.42	112.74	115.06	117.37

Table A7. LCOE (2018 \$/MWh) for 727-MW NGCC scenarios.

Scenario	SCC (2018 \$/tCO_2 Emitted)								
	20	40	60	80	100	120	140	160	180
	LCOE (2018 \$/MWh)								
BAU	46.86	46.86	46.86	46.86	46.86	46.86	46.86	46.86	46.86
BAU_SCC	54.43	62.00	69.57	77.14	84.71	92.28	99.86	107.43	115.00
CCS_NI	108.05	108.91	109.76	110.62	111.48	112.34	113.19	114.05	114.91
NR45Q	103.72	104.58	105.43	106.29	107.14	108.00	108.85	109.71	110.56
FR45Q	100.47	101.33	102.19	103.05	103.90	104.76	105.62	106.48	107.33
30FR45Q	90.83	91.67	92.50	93.34	94.18	95.01	95.85	96.69	97.52
30FR45Q_FT	83.16	84.00	84.84	85.67	86.51	87.35	88.18	89.02	89.86
30FR45Q_FT_10PISC	82.60	83.43	84.27	85.11	85.94	86.78	87.61	88.45	89.29
30FR45Q_FT_FS	80.53	81.36	82.20	83.04	83.87	84.71	85.54	86.38	87.22

Table A8. Finance gap (2018 \$/MWh) for 650-MW SubC PC scenarios.

Scenario	SCC (2018 \$/tCO_2 Emitted)								
	20	40	60	80	100	120	140	160	180
	Finance Gap (2018 \$/MWh) [Scenario X LCOE–Scenario 2 LCOE]								
CCS_NI	90.90	75.35	59.81	44.26	28.71	13.16	−2.39	−17.94	−33.49
NR45Q	79.39	63.84	48.28	32.72	17.17	1.61	−13.95	−29.50	−45.06
FR45Q	71.39	55.78	40.18	24.57	8.96	−6.64	−22.25	−37.86	−53.46
30FR45Q	46.65	31.05	15.44	−0.17	−15.77	−31.38	−46.99	−62.59	−78.20
30FR45Q_FT	34.55	18.94	3.33	−12.27	−27.88	−43.49	−59.09	−74.70	−90.31
30FR45Q_FT_10PISC	33.46	17.86	2.25	−13.36	−28.96	−44.57	−60.18	−75.78	−91.39
30FR45Q_FT_FS	29.29	13.68	−1.93	−17.53	−33.14	−48.75	−64.35	−79.96	−95.57

Table A9. Finance gap (2018 \$/MWh) for 727-MW NGCC scenarios.

Scenario	SCC (2018 \$/tCO_2 Emitted)								
	20	40	60	80	100	120	140	160	180
	Finance Gap (2018 \$/MWh) [Scenario X LCOE–Scenario 2 LCOE]								
CCS_NI	53.62	46.90	40.19	33.48	26.76	20.05	13.34	6.62	−0.09
NR45Q	49.29	42.58	35.86	29.14	22.43	15.71	9.00	2.28	−4.44
FR45Q	46.04	39.33	32.62	25.90	19.19	12.48	5.76	−0.95	−7.66
30FR45Q	36.40	29.67	22.93	16.20	9.46	2.73	−4.01	−10.74	−17.47
30FR45Q_FT	28.73	22.00	15.26	8.53	1.80	−4.94	−11.67	−18.41	−25.14
30FR45Q_FT_10PISC	28.17	21.43	14.70	7.96	1.23	−5.51	−12.24	−18.98	−25.71
30FR45Q_FT_FS	26.09	19.36	12.63	5.89	−0.84	−7.58	−14.31	−21.05	−27.78

The LCOE data from Tables A6 and A7 can be plotted to create linear SCC to LCOE relationships for each scenario (scenarios 2 through 9), which is shown in Figure 5 in the study. These plots can be used to define SCC and policy scenarios required for CCS deployment.

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