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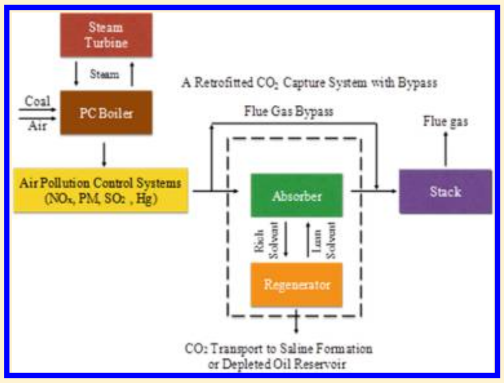
Opportunities for Decarbonizing Existing U.S. Coal-Fired Power Plants via CO_2 Capture, Utilization and Storage

Haibo Zhai,*,[†] Yang Ou,[§] and Edward S. Rubin[†,§]

[†]Department of Engineering and Public Policy, Carnegie Mellon University, Pittsburgh, Pennsylvania 15213, United States
[§]Department of Mechanical Engineering, Carnegie Mellon University, Pittsburgh, Pennsylvania 15213, United States

Supporting Information

ABSTRACT: This study employs a power plant modeling tool to explore the feasibility of reducing unit-level emission rates of CO_2 by 30% by retrofitting carbon capture, utilization, and storage (CCUS) to existing U.S. coal-fired electric generating units (EGUs). Our goal is to identify feasible EGUs and their key attributes. The results indicate that for about 60 gigawatts of the existing coal-fired capacity, the implementation of partial CO_2 capture appears feasible, though its cost is highly dependent on the unit characteristics and fuel prices. Auxiliary gas-fired boilers can be employed to power a carbon capture process without significant increases in the cost of electricity generation. A complementary CO_2 emission trading program can provide additional economic incentives for the deployment of CCS with 90% CO_2 capture. Selling and utilizing the captured CO_2 product for enhanced oil recovery can further accelerate CCUS deployment and also help reinforce a CO_2 emission trading market. These efforts would allow existing coal-fired EGUs to continue to provide a significant share of the U.S. electricity demand.



INTRODUCTION AND OBJECTIVES

In June 2014, the U.S. Environmental Protection Agency (EPA) proposed a Clean Power Plan that establishes state-specific rate-based goals for carbon dioxide (CO_2) emissions from existing electric generating units (EGUs). The proposal is to reduce nationwide carbon pollution by an average of 30% below 2005 levels in 2030.[1] To formulate a consistent national basis, the EPA established four "building blocks" for emission reductions. However, each state has the flexibility of choosing mitigation measures to meet the overall emission goal, including measures that are not mentioned in any of the four building blocks. Carbon capture and storage (CCS) is not included in the building blocks, mainly because of concerns about substantially increased costs and space limitations. However, the EPA also recognizes the potential viability of partial CCS at some plants.[1]

Compared to new plants, existing coal-fired EGUs often have lower unit efficiency and higher marginal operating costs.[2] Multiple EGUs within a single plant might have different attributes. Given the large cost and high energy penalty associated with amine-based CCS systems,[3,4] previous studies indicate that retrofitting amine-based CCS to existing coal-fired plants would lead to substantial increases in the cost of electricity generation (COE).[5,6] The lifetime of the CO_2 capture facilities can be limited by the remaining life of existing plants. These factors are often viewed as critical barriers to CCS deployment.[6] However, for existing coal-fired EGUs that have been fully or substantially amortized, the COE of an EGU retrofitted with CCS can be comparable to or lower than that of a new plant.[6] Relatively large, young, high-efficiency coal-fired EGUs equipped with flue-gas desulfurization (FGD) and selective catalytic reduction (SCR) systems are potentially suitable for CCS retrofit applications.[7,8] Auxiliary power systems can be used to maintain the electricity output of retrofitted plants.[4,9,10] Thus, the feasibility of a CCS retrofit should be evaluated on a site-specific basis because the retrofit cost varies significantly with unit characteristics.[5,11] As a revenue-enhancing opportunity, selling the captured CO_2 product for enhanced oil recovery can lower the added cost for CCS.[10]

It remains unclear with the prospect for CCS retrofits of U.S. coal-fired generating capacity (totaling 318 gigawatts)[12] to help comply with the EPA's newly proposed regulations. Thus, the EPA seeks comments on the extent to which EGUs could be retrofitted with CCS. The major objectives of this study, therefore, are to (1) investigate the feasibility of retrofitting CO_2 capture, utilization, and storage (CCUS) to existing U.S. pulverized-coal-fired EGUs to achieve a 30% reduction in unit-level CO_2 emission rates; (2) identify which EGUs are feasible for partial CO_2 capture by examining how unit characteristics would impact retrofit cost and feasibility; and (3) explore other mechanisms that can improve the retrofit viability for feasible EGUs. This paper thus presents the first comprehensive

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analysis of the potential for CCS to contribute to the CO_2 emission reductions called for in the recent EPA proposal. In particular, this study identifies the key attributes of EGUs where CCS is most feasible; estimates the costs of CCS retrofits for feasible units; and quantifies the roles of CO_2 emissions trading and CO_2 product utilization for enhanced oil recovery in facilitating CCUS deployment as a compliance measure for feasible EGUs.

■ MATERIALS AND METHODS

A power plant simulation model is employed in conjunction with unit-specific databases to evaluate each coal-fired EGU in the existing fleet of U.S. power plants. To assess the nationwide feasibility of retrofitting CCS for compliance with proposed EPA reductions in CO_2 emissions from existing plants, commercially available postcombustion amine-based systems are assumed to be employed for CO_2 capture.[3,10] Other capture technologies still under development were considered to be ill-suited and/or not yet available for the applications of interest in this study.

Electric Generation and Emissions Databases of Existing Coal-Fired Fleet. This study uses two electric generation and emissions databases of the existing U.S. power generation fleet: the National Electric Energy Data System v5.13 (NEEDS), and the Emissions & Generation Resource Integrated Database with data for 2010 (eGRID).[13,14] NEEDS includes basic geographic information, unit identification number (ID), boiler type, net summer peak capacity, net heat rate, fuel type, boiler online year, environmental control systems, and their online time for each EGU.[13] eGRID is the major source of data on the environmental characteristics of electric power facilities, including air emissions, annual net generation, resource mix, and many other attributes.[14] The two databases are linked via the unit ID along with the Federal Energy Regulatory Commission form that reports their gross electricity generation.[15,16]

For retrofit assessments, EGUs were selected from the combined data set using the screening rules: pulverized-coal-fired units operating in 2010; more than 25 megawatt in capacity, fired only by coal, and used only for electricity generation; less than 60 years old in terms of boiler age; less than a 20% unit parasitic load, based on the difference between gross and net power outputs; and CO_2 emission rates falling within a physically reasonable range, not smaller than that of a new supercritical bituminous coal plant or larger than 3000 lbs/MWh.[16] These criteria resulted in 627 EGUs being selected for a total capacity of about 250 gigawatts. The selected EGUs are characterized by the major attributes including the unit age, boiler type, coal type, capacity, net heat rate, annual electricity generation, operating hours, and environmental control systems and their ages. The average power output is estimated as the product of annual electricity generation divided by annual operating hours, while the average capacity factor is estimated as the percentage of actual operating hours over total hours in a year. The net efficiency is derived from the unit heat rate. These attributes are used to specify existing coal-fired EGUs.

Computational Tool. To examine the feasibility of CO_2 capture retrofits, the Integrated Environmental Control Model (IECM, version 8.0.2) developed by Carnegie Mellon University was employed in conjunction with the aforementioned databases.[17] The IECM performs systematic estimates of the performance, emissions, and costs for fossil fuel-fired power generation systems, including pulverized coal (PC) and natural gas-fired combined cycle (NGCC) systems equipped with CCS.[17] The IECM has an array of power plant configurations that can employ a variety of fuels and environmental control systems. Power plant and process performance models are developed based on fundamental mass and energy balances together with empirical data, and are further linked to engineering-economic models that estimate the capital cost, annual operating and maintenance (O&M) costs, and total annual levelized cost of an overall power plant with specified environmental control and cooling water systems.[17] The model employs the costing method and nomenclature outlined in the Electric Power Research Institute's Technical Assessment Guide.[18] Further details of the IECM performance and cost models are available elsewhere.[3,19−27]

In the IECM simulations, each EGU is specified in terms of its aforementioned unit attributes. When a CO_2 capture retrofit is considered, the bypass design is adopted for partial CO_2 capture because it is most cost-effective for amine-based capture systems.[28] The IECM provides estimates of all major performance and cost metrics for each simulated EGU. The performance metrics considered are CO_2 removal efficiency, net unit efficiency, and net power output. The site-specific cost metrics are total levelized cost of electricity (LCOE) of an EGU and the added LCOE for a CO_2 capture retrofit. The LCOE is calculated as[29]

$$\mathrm{LCOE} = \frac{\mathrm{TCR}\cdot\mathrm{FCF} + \mathrm{FOM}}{(\mathrm{CF}\cdot\mathrm{AHrs})\cdot\mathrm{MW}} + \mathrm{VOM} + \mathrm{HR}\cdot\mathrm{FC} \tag{1}$$

Where LCOE = levelized cost of electricity generation ($/MWh); TCR = total capital requirement ($); CF= capacity factor (%); FCF = fixed charge factor (fraction/yr); FOM = fixed O&M costs ($/yr); VOM = variable nonfuel O&M costs ($/yr); HR = net heat rate (MBtu/MWh); FC = unit fuel cost ($/MBtu); MW = net power output (MW); and AHrs = total annual hours (hrs/yr). FCF is the levelization factor for the total capital requirement of a project and is a function of the discount rate and project book life.[30] In this study, the maximum economic book lifetime is assumed to be 30 years, so existing EGUs with boilers more than 30 years old are treated as fully amortized units. For nonfully amortized EGUs less than 30 years old, the TCR given in eq 1 is adjusted by an amortization factor to estimate the unit LCOE for retrofit applications. Due to a lack of site-specific data, these "percent-amortized" factors for individual unit components are estimated as the fraction of the component age relative to the maximum economic book life.

In each CO_2 retrofit application, we first determine the CO_2 removal efficiency required for a retrofitted EGU to meet the emission-rate reduction goal, and then estimate the unit performance and costs. For a given EGU, the differences in major metrics between the cases with and without CO_2 capture are used to quantify the impacts of each retrofit application. In addition, we also estimate the cost of CO_2 avoided. It is defined as[29]

$$\text{cost of } CO_2 \text{avoided}(\$/\text{ton } CO_2) = \frac{(\mathrm{LCOE})_{\mathrm{retrofit}} - (\mathrm{LCOE})_{\mathrm{current}}}{(\mathrm{ER})_{\mathrm{current}} - (\mathrm{ER})_{\mathrm{retrofit}}} \tag{2}$$

where ER = CO_2 emission rate (tons/MWh). The subscripts "retrofit" and "current" indicate an EGU retrofitted with CCS and the current unit without CCS, respectively. Throughout

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this paper all costs are reported in constant 2009 dollars, and all emissions are in short tons.

■ RESULTS AND ANALYSES

We first analyze the characteristics of existing coal-fired EGUs and then assess the potential impacts of retrofitting the entire fleet with partial CO_2 capture. Based on these results, we identify the most feasible EGUs and their key attributes, and then estimate the costs of CO_2 avoided by CCS for those units. Furthermore, we investigate various approaches that could enhance the retrofit viability for feasible EGUs. A schematic that outlines the assessment framework is presented in Figure S-1 in the Supporting Information (SI).

Characterization of Existing Coal-Fired Generation Fleet. Table 1 summarizes major variables and assumptions for unit assessments, with the age of a device taken as the reference year minus the online year. Existing EGUs fire three ranks of coals: bituminous, sub-bituminous, and lignite. Given that the only information on fuel properties recorded in the databases is the coal rank, three surrogate coals from the IECM fuel database are used for unit assessments. In the existing fleet, 62% of EGUs have SO_x scrubbers, whereas 46% have postcombustion NO_x control devices. Particulate control devices are widely installed, but mercury control devices are largely absent. Table S-1 of the SI summarizes the coal properties and costs and SI Table S-2 summarizes the statistics of installed environmental control systems.

The existing coal-fired fleet is categorized into two groups based on the boiler age: fully and partially amortized units. As a result, there are 497 fully amortized EGUs and 130 partially amortized EGUs. Within each group, the unit attributes vary significantly. In particular, the operating hours, capacity, annual net electricity generation, and unit LCOE vary by a factor of roughly 8 to 404 for the fully amortized EGUs and by a factor of roughly 3 to 41 for the partially amortized EGUs. In comparing the two groups, the fully amortized EGUs have a higher boiler age, lower capacity, lower annual net electricity generation, fewer operating hours, and higher unit LCOE on average than the partially amortized EGUs. Table S-3 (in the SI) summarizes the statistics of major attributes for these two groups.

Retrofitting Partial CO_2 Capture to the Existing Coal-fired Generation Fleet. Existing EGUs are not fully equipped with environmental control devices for limiting emissions of all traditional air pollutants. Thus, EGUs are first upgraded by installing the missing control devices to reduce the impurities in flue gas streams entering CO_2 capture systems in order to lower solvent degradation.[31] The bypass design is adopted for partial CO_2 capture, with the fraction of flue gas bypass determined by the overall CO_2 removal efficiency required to reduce the unit-level CO_2 emission rate by 30% from the existing level.

Techno-Economic Effects of CO_2 Capture Retrofits for the Entire Fleet. Table 1 also presents the major performance and cost parameters for the amine-based capture system, excluding the CO_2 transport and storage costs, which are addressed later. To provide the thermal energy for solvent regeneration, low-quality steam is extracted from the unit's steam cycle, which increases the heat rate and the coal flow rate for a given gross power output. In addition to the thermal energy use, a sizable amount of electricity is used to power pumps, fans, and compressors in a CO_2 capture process.[10]

As a result of retrofitting the capture system and environmental control devices for traditional air pollutants (if needed),

Table 1. Major Technical and Economic Variables and Assumptions for Coal-fired EGUs and CO_2 Capture Systems

facility	category	variable	assumption/value
existing EGU		steam generator	subcritical or supercritical
	air pollution control (where applicable)	nitrogen oxides	selective catalytic reduction
		sulfur oxide	wet flue gas desulfurization or lime spray dryer
		particulate	cold-side electrostatic precipitator
		mercury	carbon injection
	cooling system	cooling technology	wet tower
	economics	cost year	2009
		dollar type	constant
		discount rate (%)	7.09%
		maximum economic book life	30 years
		unit retirement age	60 years
		unit age reference year	2010
		coal cost (\$/ton)[a]	
		bituminous	38.2
		sub-bituminous	8.75
		lignite	15.3
CO_2 capture system	performance	partial capture design	bypass
		CO_2 removal efficiency	90%
		sorbent concentration	30 wt %
		lean CO_2 loading	0.19 mol.CO_2/mol. solv.
		liquid-to-gas ratio	~3.0
		regeneration heat requirement	~1520 Btu/lb CO_2
		heat-to-electricity efficiency	19.7%
		CO_2 product pressure	2000 psia
		maximum train CO_2 Capacity	230 tons/h
	cost	construction time	3 years
		general facilities capital	10% of process facilities capital
		engineering and home office fees	7% of process facilities capital
		total contingency cost	20% of process facilities capital
		royalty fees	0.5% of process facilities capital
		monoethanolamine cost	\$2128/ton
		operating labor rate	\$34.65/h
		total maintenance cost	2.5% of total plant cost

[a]The bituminous Illinois #6, sub-bituminous Wyoming Powder River Basin, and North Dakota lignite coals in the IECM database are used as the surrogate fuels for unit assessments. Detailed coal properties and costs are available in the Supporting Information.

the implementation of partial CO_2 capture significantly decreases the net power output and efficiency and increases the LCOE of an existing unit. The results show that the overall CO_2 removal efficiencies required for retrofitted EGUs to meet

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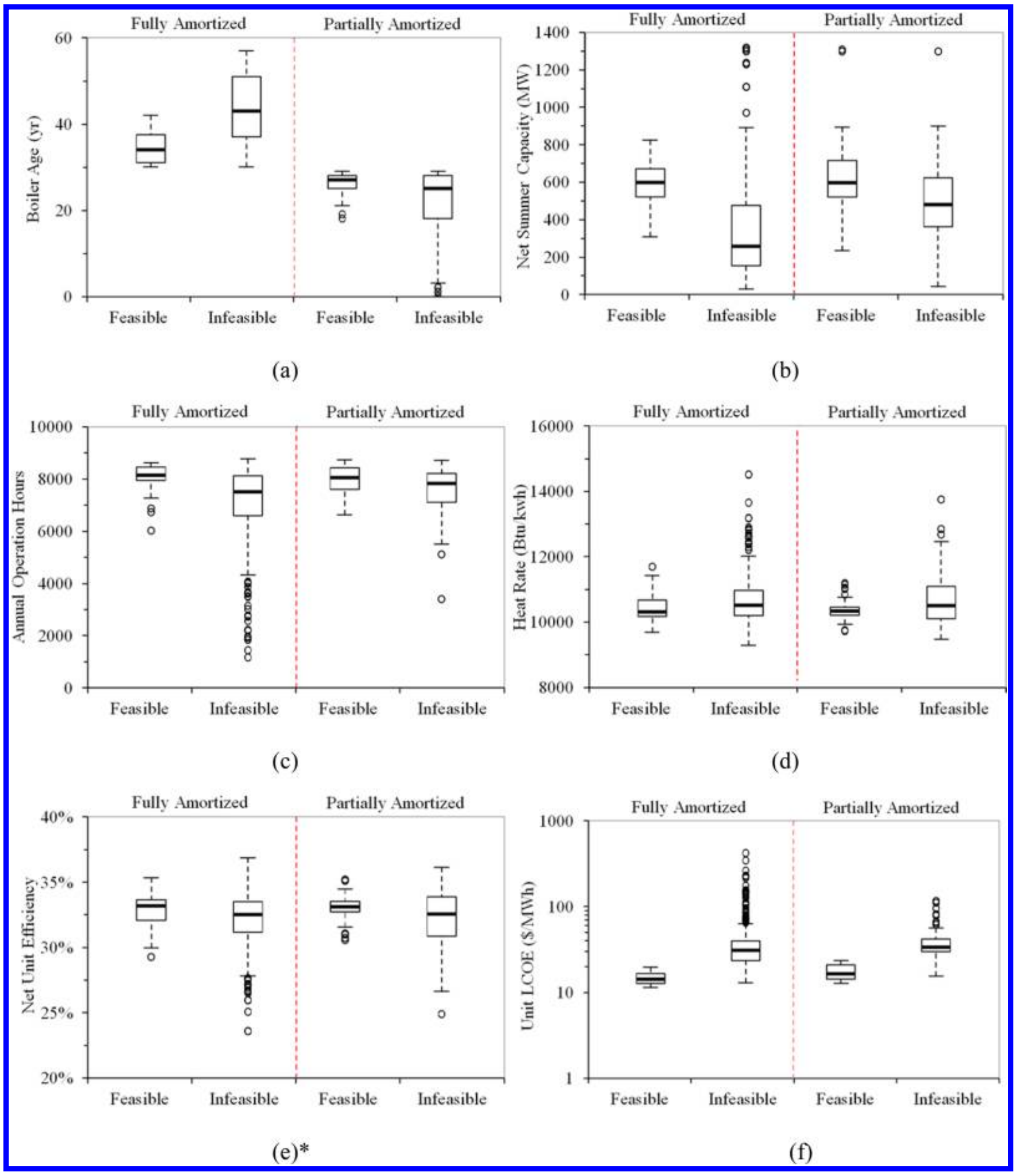

Figure 1. Characteristics of feasible and infeasible EGUs prior to CCS retrofits (a) boiler age; (b) peak capacity; (c) annual operating hours; (d) heat rate; (e) net unit efficiency; (f) LCOE. * Net efficiency is derived from the unit heat rate.

the rate-based emission reduction targets vary from 39.4% to 46.5%. The decreases in net power output and net unit efficiency fall within a range of 5.9% to 14.9% and 13.7% to 23.3%, respectively, whereas the increases in unit LCOE range from 31.0% to 432%. Adding amine-based systems would raise the unit LCOE by an average of $42.8/MWh for the entire fleet. These results indicate that retrofits are not economically feasible for a large fraction of the existing fleet. Further details are presented in SI Table S-4 summarizing the effects of retrofit applications on fleet performance and costs. Note that the average energy penalty, decrease in plant capacity, and increase in LCOE with partial CO_2 capture are smaller than values commonly found in the literature based on 90% capture efficiency.[10]

Identification of Feasible EGUs for Partial CO_2 Capture. The viability of an environmental mitigation technology depends heavily on its costs. Thus, the annual levelized cost is employed as the measure to determine the retrofit feasibility for each EGU in comparison with a benchmark. To reduce CO_2 emissions, the EPA proposed the improved utilization of NGCC plants with up to a 70% capacity factor as one of the four "building blocks".[1] Thus, our study employs existing NGCC plants with a 70% capacity factor as the benchmark for comparisons to identify the coal-fired EGUs most suitable for CO_2 capture retrofits. Table S-5 (in the SI) summarizes the performance and costs of two benchmark NGCC plants simulated in the IECM: fully and partially amortized plants. The partially amortized plant has an age equal to the average age (23 years) of all the partially amortized coal-fired boilers. The U.S. Energy Information Administration predicts that national average natural gas prices will increase by an average of 3.7%/year from $2.75/MBtu in 2012 to $7.65/MBtu in 2040.[32] Thus, the gas price assumed in our analysis is $4.5/MBtu, resulting in benchmark costs of $33.9/MWh and $37.2/MWh for fully and partially amortized NGCC plants, respectively.

For each group, any coal-fired EGU retrofitted with partial CO_2 capture that has a lower LCOE than the corresponding benchmark NGCC plant is defined as a feasible unit for partial

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CO_2 capture. Otherwise, it is infeasible. Note that this yields a conservative estimate of feasible CCS retrofits since we assume that the alternative to a CCS retrofit is an existing NGCC plant with spare capacity, rather than a new NGCC plant whose LCOE would be greater than assumed here. Additional details are shown in Figure S-2 in the SI.

As a result, 56 fully amortized EGUs and 42 partially amortized EGUs are identified to be suitable for CO_2 capture retrofits. These units account for 13.2% and 10.7% of the total fleet capacity, respectively. These suitable EGUs are distributed across 22 states, mainly Texas, Missouri, Kansas, and Wyoming, which collectively account for about 40% of the total capacity of all suitable units. Obviously, the number of feasible EGUs for CO_2 capture retrofits is also sensitive to fuel prices. Figure S-3 (in the SI) presents additional results of parametric analyses on fuel prices. Those results show that both the coal and gas prices have pronounced effects on the viability of CCS retrofits.

Characteristics of Feasible EGUs for CO_2 Capture Retrofits. Figure 1 employs box plots to further stratify each of the two groups into feasible and infeasible clusters and display the full range of variation for each key attribute. For the fully amortized group, the cluster of feasible EGUs has smaller median values of boiler age, heat rate, and unit LCOE than the infeasible cluster. It also has larger median values of net capacity, annual operation hours, and net unit efficiency. For the feasible cluster, the middle half within the interquartile range include boiler ages from 31 to 37 years, unit capacities from 521 to 671 MW, annual operating times from 7938 to 8432 h, unit LCOEs from \$12.6/MWh to \$16.4/MWh. These ranges are significantly different from those of the infeasible EGUs. However, the interquartile ranges of heat rate or net unit efficiency are to some extent overlapping between the feasible and infeasible clusters.

For the partially amortized group, there are similar findings for the median values of these unit attributes except boiler age. In addition to the heat rate or net unit efficiency, the interquartile ranges of capacity and annual operating time are partially overlapping between the feasible and infeasible clusters. Among the partially amortized EGUs, some newly or recently installed units shown in Figure 1(a) have higher LCOEs than the benchmark. Thus, they are not selected for CO_2 capture retrofits.

Figure 1 reveals that almost all suitable EGUs are between 20 and 40 years old with a net thermal efficiency of more than 30%, a capacity of more than 300 MW, and more than 6000 annual operating hours. It also turns out that all feasible EGUs are fired by sub-bituminous coal assumed to be Wyoming Powder River Basin, the cheapest of the three surrogate coals. All these factors collectively result in relatively low LCOE for feasible EGUs.

Table 2 further summarizes the statistics of major attributes for all feasible EGUs. Among the 98 candidates for CO_2 capture retrofits, 64 EGUs already have SOx control units and 27 have postcombustion NO_x controls. These units then require fewer upgrades, hence lower retrofit costs, compared with the units lacking these technologies.

To achieve the CO_2 emission reduction goal, the overall CO_2 removal requirement for feasible EGUs falls within a range of 39.4−43.4%. Adding CO_2 capture systems and missing air pollution control devices would markedly decrease the average net unit efficiency from 33.0% to 27.1%, reducing the average net power output from 535MW to 483MW and raising the average unit LCOE from \$15.6/MWh to \$32.0/MWh for all feasible EGUs.

Table 2. Performance and Costs of Feasible EGUs Before and After CO_2 Capture Retrofits

			EGUs retrofitted with CO_2 capture	
metrics	statistics	existing EGUs (w/o retrofit)	w/o auxiliary boiler[a]	w/ auxiliary boiler[b]
unit efficiency (HHV%)	min.	29.2	24.2	27.6
	median	33.2	26.9	30.1
	mean	33.0	27.0	30.1
	max.	35.3	30.2	32.5
net power output (MW)	min.	227.1	209.0	252.6
	median	529.3	476.4	585.8
	mean	534.7	482.5	589.3
	max.	1238.0	1115.0	1351.0
unit LCOE (constant 2009\$/MWh)	min.	11.3	25.9	31.2
	median	14.9	32.1	36.0
	mean	15.6	32.0	36.1
	max.	23.4	37.1	40.7

[a]The low-quality steam is extracted from the steam cycle. In the IECM simulation, the heat rate of an EGU retrofitted with partial CO_2 capture is estimated as the product of the existing heat rate multiplied by an adjustment factor that accounts for the thermal effect of that steam extraction. Given the default heat rates are estimated for new plants in the IECM, the adjustment factor is estimated as the ratio of steam cycle heat rates for new EGUs with and without partial CO_2 capture, which have the same configurations as retrofitted and existing EGUs, respectively. [b]The steam cycle heat rate and coal flow rate of a retrofitted EGU are the same as those of the corresponding existing EGU since no steam is extracted from the unit's steam cycle.

Auxiliary Gas Power for CO_2 Capture Retrofits at Feasible EGUs. To reduce the significant energy penalty of CO_2 retrofits, an auxiliary gas-fired power system can be employed to provide both the required thermal energy for solvent regeneration in the CO_2 capture process as well as auxiliary power that can elevate the net power plant output.[10,33] As an alternative design, an auxiliary gas-fired power system with a thermal efficiency of 35% is applied to supply both the steam and auxiliary power.[10] However, the CO_2 emission rate measured at stack has to include additional emissions from the gas-fired boiler. The auxiliary system size is determined based on the required thermal energy for solvent regeneration. The resulting CO_2 removal requirements fall within a range of 31.0−41.0% for all retrofitted EGUs. As summarized in Table 2, the deployment of auxiliary power systems would elevate the mean net efficiency by three percentage point and the mean net power output by 107 MW, but increase the mean LCOE by \$4.1/MWh for the given gas price, compared to the base retrofit cases that utilize the steam cycle thermal energy. If the auxiliary gas-fired system is sized to maintain the overall net capacity of the EGU at its original value before the CCS retrofit, the average LCOE of the unit increases by \$4.8/MWh compared to the base retrofit case. At the current lower gas price, the use of an auxiliary gas-fired power system could elevate the net power output without a significant LCOE increase. If the gas price decreases to \$2.5/MBtu, the mean LCOE falls to the level of the base retrofit scenario. Similarly,

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proportionally higher LCOEs would result from higher gas prices.

Total Cost of Retrofitting CCS to Feasible EGUs. To reflect all the cost requirements of reducing CO_2 emissions to meet the emission reduction proposal, site-specific transport and storage (T&S) costs also must be included. An analysis of optimal CCS networks and infrastructures considering site-specific sources and geological reservoirs for all retrofits[34] is beyond the scope of this paper. Instead, a total T&S cost of $10 per short ton of CO_2 captured is assumed.[3] The resulting average LCOE of retrofitted EGUs then increases from $32.0/MWh to $37.7/MWh. The average cost of CO_2 avoided by partial CCS is $67/ton for all CO_2 retrofit applications. Note that this value is similar to the avoidance costs found for new power plants with 90% capture using postcombustion amine-based systems.[10]

To account for the difficulty of access to various plant areas as well as integration with existing facilities of a CO_2 capture system, a retrofit factor, which might vary significantly by site,[29,35] may be applied to individual cost areas. A recent study suggests a range of retrofit factors from 1.00 to 1.25 for postcombustion CO_2 capture installations.[34] In the IECM simulations, a retrofit factor was applied to all cost components of an amine-based capture system. Compared to the base cases with a retrofit factor of 1.00, the average cost of CO_2 avoided increased by $6.2/ton for a retrofit factor of 1.25 and by $12.4/ton for a retrofit factor of 1.50. Figures S-4 and S-5 in the SI provide additional details.

Effects of CO_2 Emissions Trading. The Clean Power Plan provides states with the flexibility to choose "'outside-the-fence"' measures to achieve the proposed emission rate goals, including emissions trading programs and multistate compliance strategies.[1] For amine-based CCS, the most cost-effective level of CO_2 control in terms of the avoidance cost is at a removal efficiency of about 90%.[28,36] Therefore, depending on the CO_2 trading price, it is economically attractive to employ CCS for 90% CO_2 capture at feasible EGUs in order to provide emission reduction credits for trading within a state or region. We use the term "full CO_2 capture" when an EGU retrofitted with CCS has an overall CO_2 removal efficiency of 90%. Applications with lower CO_2 removal efficiencies are still called "partial CO_2 capture."

Figure 2 presents an example of how to estimate the amount of tradable emissions and the breakeven trading price for CO_2. As shown in Figure 2(a), the difference in annual CO_2 emissions at stack between the existing unit and the unit retrofitted with partial CCS is regarded as the mandatory duty of meeting the rate-based emission reduction goal for each feasible EGU. The difference in annual amount of CO_2 emitted at stack between the full and partial CCS retrofits is the emission reduction credit available for trading with infeasible EGUs.

Figure 2(b) shows the unit LCOE as a function of the CO_2 trading price. The horizontal dashed line represents the cost of the EGU retrofitted with partial CCS, which has no extra tradable emissions. The solid line is the cost for the full-capture case. The breakeven trading price at which the unit LCOE of both retrofit cases are equal is $38 per short ton of tradable CO_2 emissions. For CO_2 trading prices above this value, the full CO_2 capture case has a lower LCOE than the case with partial CO_2 capture, thus making full CCS economically attractive. At lower trading prices retrofitting partial CCS is more economical.

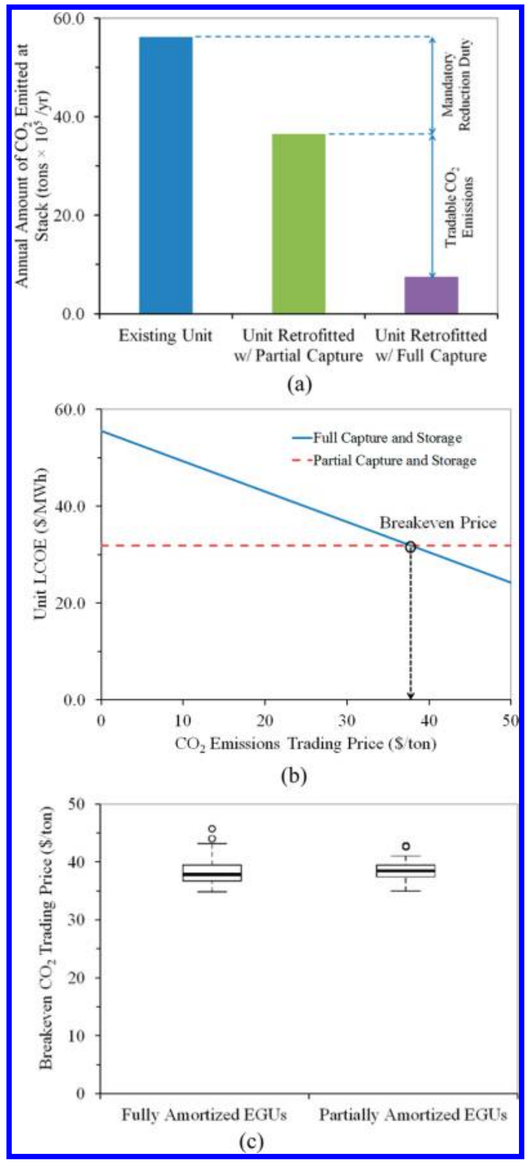

Figure 2. Breakeven CO_2 trading prices for feasible EGUs retrofitted with CCS (a) CO_2 emission reduction credit for illustrative EGU retrofitted with CCS; (b) breakeven CO_2 trading price for illustrative EGU retrofitted with CCS; (c) breakeven CO_2 trading prices for all feasible EGUs in the U.S. coal fleet (all costs in constant 2009$).

We conduct the same analysis for all feasible EGUs retrofitted with CCS and employ box plots to display the distribution of the CO_2 breakeven trading prices. As shown in Figure 2(c), there is considerable overlapped in the breakeven price distributions for the fully and partially amortized EGUs. They fall within a range of roughly $35 to $46 per short ton of tradable CO_2, which is less than the average avoidance cost for the partial CCS retrofits. This result implies that for infeasible EGUs, purchasing CO_2 emission credits from feasible EGUs retrofitted with CCS for 90% CO_2 capture would be more economical than retrofitting partial CCS to meet the proposed emission reduction goal.

Effects of CO_2 Product Utilization for Enhanced Oil Recovery (EOR). EOR is assumed to provide permanent CO_2 storage after oil is extracted. Selling and utilizing the captured CO_2 for EOR can lower the retrofit cost by providing income in lieu of a CO_2 storage cost. We refer to this case as CCUS

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(consistent with the prevailing nomenclature). Note, however, the cost of transporting captured CO_2 to an EOR site needs to be included, and is assumed here to be \$3 per short ton of CO_2 for all cases.[10]

Figure 3(a) presents an illustrative example showing how the CO_2 sale price affects the unit LCOE of a feasible EGU

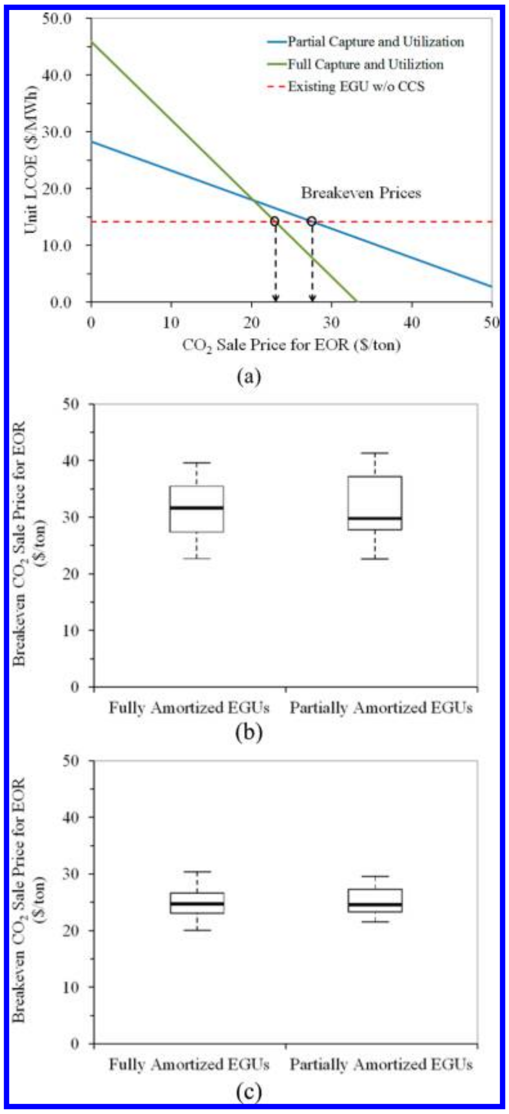

Figure 3. Breakeven CO_2 sale prices for feasible EGUs retrofitted with CO_2 capture (a) illustrative EGU; (b) partial capture and EOR utilization; (c) full capture and EOR utilization (all costs in constant 2009\$).

retrofitted with either partial or full CO_2 capture. The dashed line shown in Figure 3(a) represents the LCOE of the EGU prior to the CCUS retrofit. For both capture levels, the LCOE decreases as the CO_2 sale price for EOR increases. Figure 3(a) shows that the breakeven CO_2 sale price for the full-CCUS retrofit is lower than that for the partial-CCUS retrofit. Note that the breakeven prices refer to the levelized cost over the project lifetime.

We again conduct a similar analysis for all feasible EGUs and employ box plots to display the distribution of breakeven sale prices. For either partial or full CCUS, the distributions of breakeven sale prices for CO_2 product are similar for fully and partially amortized EGUs. Figures 3(b) and (c) show that the breakeven sale prices fall within a range of \$22 to \$42 per ton for the partial-CCUS retrofit and a range of \$20 to \$30 per ton for the full CCUS retrofit.

Combined Effects of CO_2 Emissions Trading and Utilization. CO_2 emissions trading and product utilization can be jointly considered as potential CCUS retrofits. For illustrative purposes, the CO_2-EOR market is assumed to have a sale price of \$10 per short ton of CO_2 captured. This is similar to the tax credit currently available for CO_2 sequestration via an EOR or natural gas recovery project.[37]

The example EGU shown in Figure 2(a) is employed again to illustrate how the CO_2-EOR market would affect CO_2 emissions trading. Figure 4(a) shows the LCOE as a function of CO_2 emissions trading price for the illustrative EGU retrofitted with CCUS. In contrast to the CCS retrofit case, the CCUS case has no CO_2 storage cost, but instead has an income stream from selling the captured CO_2 product for EOR. As a result, the CO_2 breakeven trading price is now \$14/ton for the

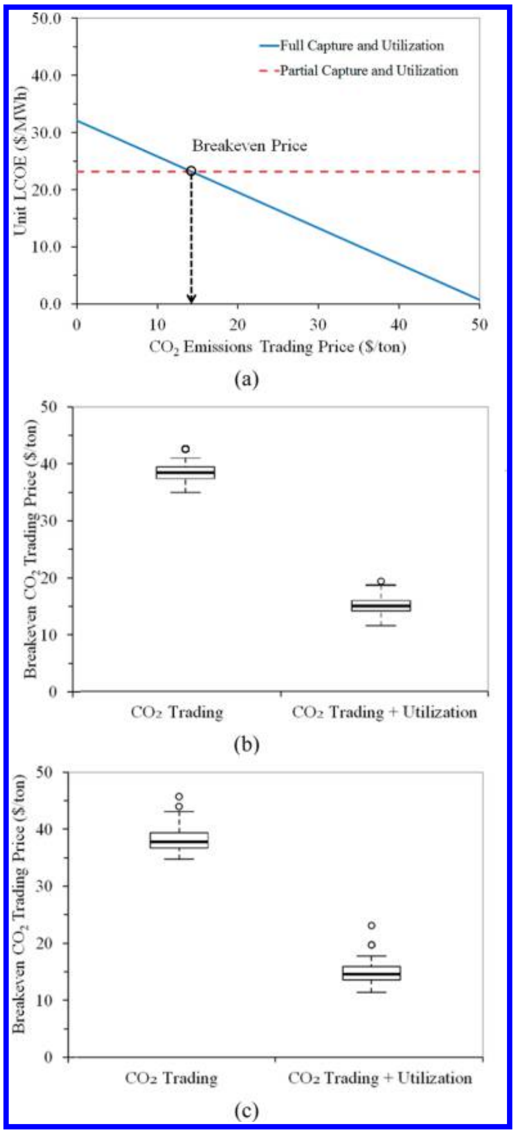

Figure 4. Comparison of breakeven CO_2 trading prices for feasible EGUs retrofitted with CCS versus CCUS (\$10/short ton CO_2 for EOR) (a) illustrative EGU; (b) all partially amortized EGUs; (c) all fully amortized EGUs (all costs in constant 2009\$).

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CCUS retrofit, which is $24/ton cheaper than the illustration of Figure 2(b).

The same analysis was conducted to estimate the CO_2 breakeven trading prices for all feasible EGUs retrofitted with CCUS. Figures 4(b) and (c) show the resulting breakeven trading prices and also comparisons between CCS versus CCUS retrofit cases for partially and fully amortized EGUs, respectively. Retrofitting full CCUS systems to feasible coal-fired EGUs is able to dramatically reduce the CO_2 emission trading prices to less than $20 per short ton. Compared to the scenario based on the CO_2 emissions trading alone, utilizing the captured CO_2 product for EOR along with the CO_2 emissions trading would decrease the CO_2 breakeven trading prices by $22/ton on average for all CCUS retrofits. Thus, CO_2 product utilization can accelerate CCUS deployment and also help reinforce a CO_2 emissions trading market.

RECOMMENDATIONS

This study explores and informs the opportunities for postcombustion CO_2 capture retrofits to significantly reduce CO_2 emissions from existing U.S. coal-fired EGUs. The implementation of partial CO_2 capture appears feasible as a measure for a sizable portion of the existing fleet to comply with EPA's newly proposed regulations. Based on the overall LCOE of existing EGUs, the most promising units for CCS retrofits are ones that are fully or substantially amortized, relatively efficient, have net capacities of more than 300 MW with high utilization, and can operate for 20 years or more. In contrast, CCS retrofits were found to be uneconomical (relative to NGCC plants) for units that are only slightly or modestly amortized, or much older, with lower efficiencies and smaller capacities needing extensive upgrades. Auxiliary gas-fired power systems may promote CCS deployment by reducing the cost of auxiliary energy requirements. An additional plant-level retrofit analysis for feasible EGUs (see Table S-6 in the SI) shows that retrofitting a large CCS system able to serve multiple EGUs within a single plant can lower the avoidance cost by an average of approximately $10/ton CO_2 relative to smaller CCS systems.

As a complementary approach, market mechanisms also can promote CCS or CCUS retrofit applications. The establishment of a CO_2 emission trading market will be helpful to provide additional economic incentives for the deployment of CCS with high CO_2 removal efficiencies at suitable coal-fired EGUs and then lower emission mitigation costs. A stable CO_2-EOR market can promote CO_2 emissions trading, accelerate CCUS deployment, and further lower the cost of low-carbon electricity generation. Sustained research, development, and demonstration programs on new-generation EOR technologies can further accelerate the integration of CO_2-EOR with CCUS. Large-scale retrofit applications also would foster "learning by doing" to drive down CCUS costs.[38,39]

Several caveats accompany this retrofit analysis: detailed site-specific models for CO_2 transport, storage and EOR costs are needed for planning CCUS infrastructures in a cost-effective manner. The availability of space at some existing sites could restrict the installation of CO_2 capture facilities or result in additional costs. In some cases, water availability also could impact the feasibility of CCUS retrofits because of the large amount of cooling water needed for current amine-based CO_2 capture processes.[27,40] Finally, the effect of a CCS system on the dispatching of units in a particular region needs further study. Thus, more detailed data on a variety of site-specific factors are needed to further refine the analysis presented here.

ASSOCIATED CONTENT

Supporting Information

Supporting Information includes additional text, tables, and figures. The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.5b01120.

AUTHOR INFORMATION

Corresponding Author

*Phone: +1 412 268 1088; fax: +1 412 268 3757; e-mail: hbzhai@cmu.edu.

Notes

The authors declare no competing financial interest.

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