The Economic Merits of Flexible Carbon Capture and Sequestration as a Compliance Strategy with the Clean Power Plan

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Supporting Information

ABSTRACT: Carbon capture and sequestration (CCS) may be a key technology for achieving large CO2 emission reductions. Relative to “normal” CCS, “flexible” CCS retrofits include solvent storage that allows the generator to temporarily reduce the CCS parasitic load and increase the generator’s net efficiency, capacity, and ramp rate. Due to this flexibility, flexible CCS generators provide system benefits that normal CCS generators do not, which could make flexible CCS an economic CO2 emission reduction strategy. Here, we estimate the system-level cost effectiveness of reducing CO2 emissions with flexible CCS compared to redispach (i.e., substituting gas- for coal-fired electricity generation), wind, and normal CCS under the Clean Power Plan (CPP) and a hypothetical more stringent CO2 emission reduction target (“stronger CPP”). Using a unit commitment and economic dispatch model, we find flexible CCS achieves more cost-effective emission reductions than normal CCS under both reduction targets, indicating that policies that promote CCS should encourage flexible CCS. However, flexible CCS is less cost effective than wind under both reduction targets and less and more cost effective than redispach under the CPP and stronger CPP, respectively. Thus, CCS will likely be a minor CPP compliance strategy but may play a larger role under a stronger emission reduction target.

INTRODUCTION

Climate change poses a serious threat to humans and natural systems. In order to avert severe climate change, carbon dioxide (CO2) emissions from the electric power sector must drastically decrease. Many studies suggest that large (>50%) CO2 emission reductions will not be possible without carbon capture and sequestration (CCS). Yet, only one utility-scale power plant equipped with CCS—the Boundary Dam plant—is currently operational worldwide. The Boundary Dam plant is equipped with amine-based post-combustion CCS, the most commercially developed CCS system, which uses liquid amine to absorb and remove CO2 from the flue gas of a coal-fired electric generating unit (EGU). “Normal” CCS retrofits like the one at the Boundary Dam plant can reduce CO2 emissions but consume substantial amounts of energy due to large parasitic loads of the CO2 capture process, which in turn substantially reduces the net power capacity of the retrofitted EGU. Large retrofit capital costs and increased operation costs associated with the large parasitic loads have hindered large-scale CCS deployment.

Relative to a normal CCS retrofit, a “flexible” CCS retrofit includes an additional feature—solvent storage—that allows the generator to eliminate most of the large parasitic loads of the CO2 capture process while maintaining a constant CO2 capture rate for up to several hours, depending on solvent storage capacity. This temporary reduction in the large parasitic loads allows a flexible CCS generator to temporarily increase its net capacity, net efficiency, and ramping capability, which in turn yields system benefits that are not available in a normal CCS generator. Furthermore, this flexibility may be increasingly valuable as the penetration of renewables and other technologies increases. Because of these system benefits, flexible CCS may be an economic strategy to reduce CO2 emissions. Flexible CCS retrofits can achieve similar benefits by venting flue gas, but venting reduces the unit’s CO2 capture rate. Here, we focus on flexible CCS as a CO2 emission reduction strategy, so we only assess flexible CCS retrofits with solvent storage.

Prior research on flexible CCS with solvent storage can largely be divided into two groups. One group used profit-maximizing optimization models with exogenous electricity prices to determine the optimal operations and profitability of flexible CCS generators. These papers demonstrated that flexible CCS units could use solvent storage to shift the parasitic load of the CO2 capture process from high to low electricity price periods, thereby arbitraging electricity price variability throughout the day. However, this arbitrage only marginally increased profits in systems with very large intra-day price differentials. Furthermore, adding solvent storage to a normal CCS generator tended to only increase the profitability
of a CCS plant at low carbon prices, when construction of a CCS generator would not be justified.\textsuperscript{7,8,12}

Other research used cost-minimizing dispatch models that demonstrated system-wide benefits of flexible CCS generators. Van der Wijk et al.,\textsuperscript{9} for instance, found that solvent storage-equipped flexible CCS generators could provide 4 to 10 times greater amounts of up reserves (including frequency regulation, Contingency, and wind power forecast error balancing reserves) than normal CCS generators, which would reduce reserve provision costs. They also demonstrated that flexible CCS could provide slight reductions in system emissions and wind curtailment compared to normal CCS. Conversely, Cohen et al.\textsuperscript{13} demonstrated benefits from increased reserve provision by venting equipped flexible CCS generators but not from adding solvent storage to those generators.

Taken together, past research suggests that a weak case exists for private investment in flexible CCS, but system benefits of flexible CCS may make it an economic \(\text{CO}_2\) emission reduction strategy. Yet, past papers did not compare flexible CCS to common \(\text{CO}_2\) emission reductions strategies like redispatching (decreasing the capacity factors of coal-fired EGU\textsuperscript{s} by increasing the capacity factors of less carbon-intensive EGU\textsuperscript{s}, mainly natural gas) and building new wind capacity. Furthermore, neither Cohen et al.\textsuperscript{13} nor Van der Wijk et al.\textsuperscript{9} included reserve provision costs in the optimization problem, which is necessary to fully value solvent storage. Thus, little information exists on the trade-offs between using flexible CCS and other strategies for reducing \(\text{CO}_2\) emissions.

Here, we begin to fill these knowledge gaps by considering flexible CCS as an emission reduction technology in the context of the Clean Power Plan (CPP) and a hypothetical "stronger CPP". The CPP set the first federal limits on \(\text{CO}_2\) emissions from existing EGU\textsuperscript{s} in the United States and aims to reduce \(\text{CO}_2\) emissions in 2030 by 870 million short tons, or 32% from 2005 levels.\textsuperscript{14} This target is meaningful but likely insufficient to meet climate stabilization goals.\textsuperscript{15} Thus, we also consider a hypothetical stronger CPP that would require a 50% reduction in existing EGU emissions (relative to 2005 levels) by 2030, using the same emission reduction framework as the CPP.

We assess the merits of flexible CCS as a CPP or stronger CPP compliance strategy with two metrics. First, we compare the cost effectiveness of \(\text{CO}_2\) emission reductions of flexible CCS retrofits to other CPP compliance strategies, namely, redispacthing, additional wind, and normal CCS retrofits. In this context, we define cost effectiveness as the total operational and capital costs per ton of \(\text{CO}_2\) emissions reduced. Second, we calculate the equivalent capital cost (ECC) for flexible CCS retrofits relative to each of the alternative compliance strategies (individually, not in aggregate), which indicates the capital cost of flexible CCS at which it would reach the same cost effectiveness and quantity of \(\text{CO}_2\) emission reductions as an alternative compliance strategy.

**Methods**

The upper Midwest area of the Midcontinent Independent System Operator (MISO), which oversees a competitive wholesale market place, will likely face a large capacity of coal-fired plant retirements\textsuperscript{16} and has good wind resources\textsuperscript{17} making it an ideal study system for changes under the CPP. As such, we conduct our study in this region, which includes North Dakota, South Dakota, Minnesota, Iowa, Wisconsin, Michigan, Missouri, Illinois, and Indiana.

**Unit Commitment and Economic Dispatch (UCED) Model.** We determine operational costs and emissions of each power plant fleet using a UCED model that minimizes total system electricity, reserve, start-up, and nonserved energy costs subject to various system- and unit-level constraints. By including reserve costs in the objective function of our UCED, we capture the changes in operating costs that result from flexible CCS generators providing system reserves. We constructed the UCED model in PLEXOS Version 7.2,\textsuperscript{18} a commercially available software package commonly used in power system analyses,\textsuperscript{19} and solved it using CPLEX Version 12.6.1,\textsuperscript{20} We ignore transmission constraints within MISO and imports and exports to and from MISO to limit problem size.\textsuperscript{21} The Supporting Information (SI) provides the complete UCED formulation and the 2030 demand profile used in the UCED.

The UCED model runs at hourly intervals for a 24-h period, like MISO’s day-ahead market,\textsuperscript{22} plus an additional 24-h look-ahead period in 6-h intervals. The look-ahead period allows us to optimize dispatch decisions over a longer time horizon and capture the value of interday solvent storage. After each optimization, the UCED model steps forward 24 h and uses the prior solution as initial conditions for the subsequent optimization. Like other UCED models,\textsuperscript{9,21,23} we assume perfect wind, solar, and demand forecasts, so do not dispatch generators in a real-time market subsequent to the day-ahead UCED solution. While this may bias our results in favor of wind power, Rahmani et al.\textsuperscript{24} find that including a real-time market within a day-ahead UCED model increases system costs and \(\text{CO}_2\) emissions by less than 1%. Thus, we expect any bias to be small and to not qualitatively change our results. Furthermore, to indirectly account for wind forecast error and the value of flexible CCS in supporting wind integration, we set hourly spinning reserve requirements to 3% of maximum daily load plus 5% of hourly wind generation.\textsuperscript{21,25} Additionally, the UCED model allows for curtailment of wind and solar generators by including them as dispatchable resources with hourly capacity factors (SI).\textsuperscript{26,27}

In order to include reserve costs in the UCED objective function, a cost coefficient, or reserve offer price, must be included with each generator’s reserve offers. To determine this coefficient, we assume that reserve offer prices are proportional to the generator’s operating cost, or marginal cost of energy.\textsuperscript{28,29} On the basis of 2015 MISO energy\textsuperscript{30} and spinning reserve offer prices,\textsuperscript{31} the capacity-weighted average proportion of spinning reserve to energy offer prices is approximately 26%. As a result, we set spinning reserve offer prices to 26% of each generator’s operating cost.

**Base Generator Fleet.** We construct a base generator fleet for 2030 for the upper Midwest portion of MISO. The base fleet accounts for fleet changes through 2030, such as generator additions and retirements, expected under the CPP. However, generator additions and retirements characterized in this base fleet are not sufficient to comply with the CPP, as CPP compliance will be largely driven by redispacthing, i.e., scheduling lower-emitting plants to generate more electricity than they would in the absence of the CPP. As a result, while our base fleet accounts for power plant additions and retirements (some of which may be driven by the CPP), we define our compliance scenarios as the additional strategies that would enable the base fleet to comply with the CPP. Such strategies include redispacthing, adding wind capacity, and/or adding normal or flexible CCS retrofits to this 2030 base fleet.
It could be argued that adding our compliance strategies to a 2030 base fleet instead of a 2015 fleet may underestimate the cost effectiveness of these strategies because CCS could replace some of the fleet changes we assume will occur between now and 2030 as states comply with the CPP. We suggest, however, that many of these fleet changes through 2030, particularly coal plant retirements and renewable capacity additions, would likely occur even without the CPP due to existing environmental regulations and state-level policies such as Renewable Portfolio Standards. Furthermore, since the Clean Energy Incentive Program under the CPP incentivizes early deployment of energy efficiency and renewables, these technologies will likely be deployed prior to CCS. Thus, our analysis considers CCS as a post-2030 CPP compliance strategy, which provides sufficient time to plan for CCS deployment. Finally, by also analyzing larger emission reductions under a hypothetical stronger CPP with the same 2030 base fleet, we capture the effect on costs and emissions from each compliance strategy in a generator fleet that has not already changed in response to an emission reduction target, thereby eliminating any bias that may occur in our CPP analysis.

To build our base fleet, we rely on a 2030 generator fleet from the EPA’s Integrated Planning Model (IPM), a cost-minimizing dispatch and capacity expansion optimization model for the U.S. electric power system that forecasts generator additions, retirements, control technology retrofits, and other changes in the power plant fleet in response to regulations. To compensate for omitted data and aggressive hydropower deployment, we alter the IPM fleet in several ways, including changing power plant heat rates and adding necessary unit commitment parameters like ramp rates, as further described in the SI. Our final base fleet consists of 1232 generators with a total capacity of 164 GW, including 50 GW coal fired, 54 GW gas fired, 33 GW wind, and 18 GW nuclear capacity. The SI provides additional installed capacity details and fuel prices.

**CPP Compliance Scenarios.** States can comply jointly with the CPP under a single rate- or mass-based target. Given that states have extensive experience with the SO2 cap-and-trade program, we assume that states in our study region will comply jointly with the CPP or stronger CPP under a single regional mass-based limit that equals the sum of each state’s mass limit. Under the CPP, the regional CO2 emissions mass limit equals 249 million tons in 2030, or 50% below 2005 emissions. To test the sensitivity of our results to larger emission reductions, we also assess a hypothetical “stronger CPP”, under which the regional CO2 emissions mass limit equals 346 million tons in 2030, or 32% below 2005 emissions. Since the EPA projects that redispersing among affected EGUs in combination with building additional wind power capacity will account for the bulk of emission reductions under the CPP, we include these as our first two strategies. Additionally, we include normal and flexible CCS retrofits.

**Redispatching among Affected EGUs.** Enforcing redispersing to comply with the CPP through a mass limit in our UCED model would be intractable, as it would require running the UCED for an entire year at once. Instead, we enforce redispersing among affected EGUs by including a CO2 price on emissions from all affected EGUs as described in Oates and Jaramillo. Note that we include this CO2 price not to analyze a carbon tax but to achieve sufficient redispersing within the UCED model among affected EGUs to comply with the CPP. The SI describes our selection of affected EGUs. To calculate this CO2 price, we use a simple economic dispatch (ED) model. The ED model, fully described in the SI, minimizes total energy costs subject to the constraints that supply equals net demand and each generator’s electricity generation varies between zero and its maximum capacity. Net demand equals demand minus wind and solar generation based on the same capacity factors as the UCED model. To determine the CO2 price, we increment a CO2 price upward from $0/ton in $1/ton increments until CO2 emissions from affected EGUs meet the regional mass limit in the simple ED. We then include these CO2 prices in the operating cost and reserve offer prices of affected EGUs in the full UCED.

**Normal and Flexible CCS Retrofits.** To evaluate CCS as a compliance mechanism, we model CCS systems with a 90% CO2 capture rate, which maximizes the efficiency of the CO2 removal process in a cost-effective manner.We select coal-fired generators for CCS retrofits based on four common attributes of coal-fired generators for which CCS retrofits are most economic: generators (1) younger than 40 years old (as of 2020), (2) with net thermal efficiencies greater than 30%, (3) with net capacities greater than 300 MW, and (4) with SO2 scrubbers and selective catalytic reduction (SCR) for post-combustion NOx control. From this group of eligible generators, we retrofit CCS on generators in order of decreasing net efficiency prior to the CCS retrofit because more efficient generators are more likely to be economically viable to operate and, therefore, profitable post-CCS retrofit.

In order to examine how the cost effectiveness of CO2 emission reductions changes with increasing CCS deployment, we construct three normal and three flexible CCS compliance scenarios for the CPP and stronger CPP each (for a total of 12 CCS scenarios) by modeling CCS retrofits on coal-fired generators. To determine the retrofit CCS capacity in these scenarios, we first assume all eligible coal-fired generators (per the four above criteria) retrofit CCS, then assume two lower capacities of CCS retrofits. This process yields combined net CCS capacities of 2, 4.5, and 8.5 GW. After accounting for the net capacity penalty of CCS retrofits, the derated CCS-equipped coal-fired capacities in these scenarios are 1.6, 3.9, and 6.2 GW, respectively, or up to 4% of the total installed capacity of the base fleet. With 6.2 GW of CCS-equipped generators, the scenario complies with the CPP without a CO2 price. However, the other two scenarios require some redispersing in addition to the CCS retrofits to comply with the CPP, so we also enforce redispersing in those scenarios via a CO2 price determined with the simple ED model. The same CCS installed capacities are also used in compliance scenarios with our hypothetical stronger CPP, as no additional coal-fired generators meet the four above criteria for CCS retrofits.

**Additional Wind Capacity.** In order to model compliance using wind power instead of CCS, we create three wind compliance scenarios under the CPP and under the stronger CPP. To create each wind scenario, we add wind capacity to the 2030 base fleet until the scenario’s CO2 price necessary to comply with the CPP as calculated with the simple ED model equals that of a CCS scenario. By controlling for CO2 price between the CCS and wind compliance scenarios, we hold constant the effects of redispersing on emissions and costs, which allows for a direct comparison between additional wind and normal and flexible CCS retrofits as compliance strategies. Relative to the base fleet, which already includes 33 GW of installed wind capacity, this results in 2.5, 5.5, and 6.5 GW of additional wind power capacity under the CPP and 3, 9, and 14
GW of additional wind power capacity under the hypothetical stronger CPP. The SI provides the CO2 price included in each compliance scenario.

Normal and Flexible CCS Models. In order to include CCS in our UCED model, we need operating parameters for retrofitted coal-fired generators. For this analysis, we assume the maximum fuel input to the boiler at a coal-fired generator remains constant before and after the CCS retrofit and that no auxiliary boilers are installed. As such, the coal-fired generator must provide the entire parasitic load of the CCS system, meaning its net efficiency and capacity, and therefore ramp rate decrease upon CCS retrofit. Given elevated SO2 removal requirements of CCS, we also zero out SOX emissions upon CCS retrofit. To estimate generator-specific CCS retrofit parameters, e.g., net capacity and heat rate penalties, we rely on linear regressions based on data from the Integrated Environmental Control Model (IECM), a power plant modeling tool, as detailed in Craig et al. We use net heat rate as the independent parameter for these regressions and develop separate regression models for bituminous and sub-bituminous coal.

A coal plant with flexible CCS has additional specific operating constraints compared to normal CCS. To account for these operating constraints, we develop a flexible CCS operational model that provides constraints that can be included in the UCED model and estimates operational costs and emissions across flexible CCS operations. This flexible CCS model disaggregates a single flexible CCS generator into eight separate proxy units that account for net electricity generation, costs, and emissions of the flexible CCS generator in different operational modes, e.g., while discharging stored lean solvent. Proxy unit operations are linked through numerous constraints. To estimate flexible CCS design and operational parameters, we use a literature review and regressions based on IECM data. Table 1 summarizes key normal and flexible CCS parameters.

Table 1. Key Normal and Flexible CCS Design and Operational Parameters

<table>
<thead>
<tr>
<th>Normal or Flexible CCS Parameter</th>
<th>Value</th>
</tr>
</thead>
<tbody>
<tr>
<td>Normal CCS retrofit efficiency penalty</td>
<td>32–46%</td>
</tr>
<tr>
<td>Normal CCS retrofit capacity penalty</td>
<td>24–32%</td>
</tr>
<tr>
<td>Normal CCS generator ramp rate</td>
<td>1.5–2.9% of capacity/min</td>
</tr>
<tr>
<td>Flexible CCS generator max reduction in CCS retrofit parasitic load while discharging stored lean solvent</td>
<td>90%</td>
</tr>
<tr>
<td>Flexible CCS generator ramp rate while discharging stored lean solvent</td>
<td>4% of capacity/min</td>
</tr>
<tr>
<td>Flexible CCS solvent storage capacity (i.e., max hours of peak power output enabled by discharging stored lean solvent)</td>
<td>2 h</td>
</tr>
</tbody>
</table>

*See the SI for additional details and Craig et al. for a full description of our flexible CCS model.*

The SI further details these and other CCS parameters, and Craig et al. provide a complete description of our flexible CCS model.

Cost Effectiveness and Equivalent Capital Cost Calculations. The results of the UCED model provide the basis for comparing operational costs and benefits of our compliance scenarios. However, that model does not account for capital costs of new wind installations or CCS retrofits. In order to compare the effectiveness of our compliance scenarios, a consistent metric must be used that accounts for all costs and CO2 emissions benefits. We therefore calculate the cost effectiveness (CE) of reducing CO2 emissions for each compliance scenario (c) as

\[
CE_c = \frac{\text{TOC}_c + \text{TCC}_c - \text{TOC}_{\text{Base}}}{\text{ACE}_c - \text{ACE}_{\text{Base}}}
\]

where Base refers to the base fleet; TOC = total operational costs, or the sum of electricity generation, start-up, and reserve costs [$2011$]; TCC = total annualized capital costs of additional wind capacity or CCS retrofits added in our compliance scenarios [$2011$]; and ACE = total CO2 emissions from affected WTs [tons]. The SI specifies how we calculate TOC and the capital recovery factor (CRF) we use to annualize capital costs. We assume revenues collected through a carbon market are recycled into the electric power sector, so they do not constitute real economic costs and are not included in TOC. To account for uncertainty in capital costs of wind and CCS retrofits, we calculate cost effectiveness over a range of capital costs (SI).

With these cost-effectiveness estimates, we calculate a per-kW equivalent capital cost (ECC) for flexible CCS relative to each compliance strategy. Each ECC indicates the capital cost of flexible CCS retrofits at which such retrofits would reach the same cost effectiveness and quantity of CO2 emission reductions as an alternative compliance strategy. We calculate the ECC as

\[
\text{ECC}_c = \left( \frac{\text{CE}_c \times \text{ACE}_c - \text{TOC}_c}{\text{FCC}_c} \right) \times \frac{1}{\text{CRF}_c}
\]

where f and a indicate flexible CCS and alternative compliance strategies, respectively, and FCC = installed derated capacity of flexible CCS [MW]. We use the same CRF as eq 1.

**RESULTS**

CO2 Emission Reductions in Compliance Scenarios. Figure 1 highlights that the base 2030 fleet does not, on its own, comply with either policy, but its CO2 emissions are much closer to the CPP than stronger CPP mass limit. Consequently, CO2 emission reductions relative to the base fleet under the stronger CPP compliance scenarios are 5 to 7 times greater than those under the CPP compliance scenarios. For instance, the redispatch scenario reduces CO2 emissions relative to the base fleet by 20 and 120 million short tons under the CPP and stronger CPP, respectively, a 6-fold difference. Due to the large difference in CO2 emission reductions necessary to comply with the CPP and stronger CPP, compliance scenarios’ generation mixes differ substantially between the two reduction targets. Most notably, coal-fired generation, which provides 50% of electricity generation in the base fleet, declines by 5–10% and 38–45% in compliance scenarios under the CPP and stronger CPP, respectively. The SI provides the generation mix for each compliance scenario.

Since we set the CO2 price for each compliance scenario using a simple ED model that does not account for all system constraints, that price does not guarantee emission reductions in the full UCED model. In fact, Figure 1 indicates that the scenario that reduces emissions solely through redispatching does not comply with the CPP, whereas the compliance scenarios that reduce emissions partly through additional wind or CCS retrofits do not comply with the stronger CPP. However, these instances of noncompliance are a construct of using a CO2 price determined by a simplified ED model to...
comply with the relevant emission mass limits, not an indication that the strategy could not be used to comply with the mass limit. Indeed, affected EGU CO₂ emissions under these scenarios only exceed the relevant mass limit by less than 2.5%. Thus, we subsequently analyze these scenarios in the same way as scenarios that comply with the relevant mass limit.

**Total Costs.** This section discusses the total annualized costs included in the cost-effectiveness calculation for each compliance scenario (see numerator of eq 1). Electricity generation costs dominate total annualized costs under the CPP and stronger CPP. In the dispatch CPP compliance scenario, for instance, annual electricity generation costs equal $13.2 billion ($2011), whereas start-up and reserve costs equal $0.1 and $0.3 billion, respectively. Total annualized costs also include annualized capital costs of new wind or CCS added in the compliance scenarios, which account for 1% to 10% of total costs, depending on the scenario.

Table 2 provides total annualized cost increases relative to the base scenario for each CPP and stronger CPP compliance scenario assuming best guess capital cost values. Among our CPP compliance scenarios, total annualized costs relative to the base scenario increase between $100 million in the redispatch scenario and $2.3 billion in the 6.2 GW normal CCS scenario. Given that redispatching increases costs the least, substituting redispatching with additional wind or CCS increases total annualized costs. Total costs increase less under wind, which provides zero marginal cost electricity, than flexible CCS. Flexible CCS, in turn, provides greater reserves than normal CCS and therefore further reduces reserve costs, resulting in lower total annualized costs than normal CCS. However, since reserve costs account for only a small fraction of total annualized costs, the latter costs are not substantially lower with flexible than normal CCS. Under the stronger CPP, redispatch costs increase relative to the CPP as electricity generation increasingly shifts to units with lower CO₂ emissions rates but higher operational costs. Unlike under the CPP, costs increase the most under redispatching, and substituting

<table>
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<tr>
<th>compliance scenario</th>
<th>CPP</th>
<th>stronger CPP</th>
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<tbody>
<tr>
<td>redispatch</td>
<td>100</td>
<td>2770</td>
</tr>
<tr>
<td>wind, 2.5 GW†</td>
<td>140</td>
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<td>wind, 5.5 GW†</td>
<td>230</td>
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<tr>
<td>wind, 6.5 GW</td>
<td>270</td>
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<td>wind, 3 GW*</td>
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</tr>
<tr>
<td>wind, 14 GW*</td>
<td>N/A</td>
<td>1580</td>
</tr>
<tr>
<td>normal CCS retrofits, 1.6 GW†*</td>
<td>350</td>
<td>2580</td>
</tr>
<tr>
<td>normal CCS retrofits, 3.9 GW†*</td>
<td>840</td>
<td>2450</td>
</tr>
<tr>
<td>normal CCS retrofits, 6.2 GW*</td>
<td>1280</td>
<td>2490</td>
</tr>
<tr>
<td>flexible CCS retrofits, 1.6 GW†*</td>
<td>330</td>
<td>2560</td>
</tr>
<tr>
<td>flexible CCS retrofits, 3.9 GW†*</td>
<td>780</td>
<td>2410</td>
</tr>
<tr>
<td>flexible CCS retrofits, 6.2 GW*</td>
<td>1180</td>
<td>2400</td>
</tr>
</tbody>
</table>

† and * indicate wind and CCS compliance scenarios that include some redispatching under the CPP and stronger CPP, respectively.

Figure 1. Total emissions from affected EGUs under the CPP (left) and stronger CPP (right) from our UCED model, plus each emissions mass limit (black line). The * indicates wind and CCS compliance scenarios that include some redispatching.
Cost Effectiveness of CO₂ Emission Reductions. Cost Effectiveness under the CPP. Our results indicate that the cost of complying with the CPP varies among compliance strategies from $0 to $60 per ton of avoided CO₂ (Figure 2). Depending on wind capital costs, redispatching or wind achieves the most cost-effective CO₂ emission reductions, whereas normal CCS achieves the least cost-effective reductions. Additionally, replacing redispatching with wind or CCS increases the quantity of emission reductions. Consequently, a trade-off exists between cost effectiveness and quantity of emission reductions when substituting CCS or wind for redispatching, except at low wind capital costs (less than $1650/kW). Among CCS technologies, flexible CCS tends to achieve greater emission reductions more cost effectively than normal CCS, with the exception of the 1.6 GW CCS scenarios, which have low utilization rates at one retrofit CCS plant.41

At each capacity of normal or flexible CCS retrofits, similar or greater reductions can be obtained more cost effectively with additional wind capacity. For instance, the 5.5 and 6.5 GW wind scenarios achieve similar emission reductions as the 6.2 GW CCS scenarios but at roughly a fifth of the cost. Additionally, while the 1.6 GW CCS scenarios can achieve as cost-effective emission reductions as the 5.5 or 6.5 GW wind scenarios, the emission reductions they achieve are roughly 13% lower.

Cost Effectiveness under the Stronger CPP. Costs of compliance with the stronger CPP range from $7 to $23 per ton (Figure 2). Redispatching achieves the most emission reductions but is the least cost effective, as the addition of wind or CCS increases cost effectiveness (by up to 40%) and decreases emission reductions (by up to 7%). This trend opposes that under the CPP, indicating the increasing cost effectiveness of CCS and wind relative to redispatching under a stronger emission reduction target. Two factors mostly account for these opposing trends: higher redispatch costs and higher capacity factors of CCS-equipped generators under the stronger CPP.41 Higher CCS capacity factors yield greater system benefits for the same capital cost, thereby increasing the cost effectiveness of CCS.

Additional wind capacity tends to be a more economic compliance strategy than flexible and normal CCS, as under the CPP. The 9 and 14 GW wind scenarios provide similar emission reductions at greater cost effectiveness (by 20–35%) than the 3.9 and 6.2 GW normal and flexible CCS scenarios. All wind scenarios also achieve more cost-effective emission reductions than the 1.6 GW CCS scenarios but the 1.6 GW CCS scenarios achieve more emission reductions.

Flexible CCS tends to be a more economic compliance strategy than normal CCS, and under the CPP. At all tested capacities, flexible CCS achieves more cost-effective emission reductions than normal CCS. Furthermore, at 1.6 and 3.9 GW of CCS retrofits, flexible CCS achieves greater emission reductions than normal CCS. However, at 6.2 GW, flexible CCS achieves less emission reductions due to less electricity generation by CCS-equipped generators.41

The 3.9 and 6.2 GW CCS scenarios are the only two scenarios that are less cost effective under the CPP than stronger CPP for two reasons. First, utilization of CCS-equipped generators decreases with increasing CCS penetration under the CPP (but not the stronger CPP), increasing costs and reducing cost effectiveness. Second, while CCS retrofits substitute for redispatching under both targets, redispatching is a cost-effective CO₂ emission reduction strategy under the CPP but not the stronger CPP. Consequently, increasing CCS under the CPP reduces redispatching and, in turn, cost effectiveness. Indeed, in the 6.2 GW normal CCS scenario under the CPP, no redispatching and low CCS capacity factors combine to create the least cost-effective compliance scenario under both targets.

Flexible CCS ECCs. Relative to the wind compliance scenarios, flexible CCS ECCs are negative or below the lowest flexible CCS capital cost estimate used in the cost-effectiveness analysis, or $1170/kW, under the CPP and stronger CPP (SI). Negative ECCs indicate that even if the capital cost of flexible CCS was zero, flexible CCS would still be more expensive than the alternative compliance strategy due to the energy penalty and, consequently, high operating cost of CCS. ECCs relative to redispatching are also negative under the CPP but range from $2000–$2900/kW under the stronger CPP, above current capital cost estimates.

Figure 2. Cost per ton of CO₂ emission reductions versus CO₂ emission reductions for each compliance scenario relative to the base scenario under the CPP (left) and stronger CPP (right). Error bars indicate cost per ton at low and high capital cost values, dashed vertical lines indicate the trends. Conversely, under the stronger CPP, aggregate capacity factors of CCS-equipped generators decreases emission reductions (by up to 7%). This trend exists between cost effectiveness of CCS and wind relative to redispatching under the CPP, ranging from $7 to $23 per ton of emission reductions.
estimates of flexible CCS capital costs (1170–1490 $/kW), indicating that flexible CCS would likely be a more cost-effective carbon mitigation strategy than redispachting under the stronger CPP. Across installed CCS capacities under the CPP and stronger CPP, ECCs relative to normal CCS range from 1300−1600, some of which exceed the upper flexible CCS capital cost estimate (1490/kW), also indicating that flexible CCS would likely be a more cost-effective carbon mitigation strategy than normal CCS given best guess flexible CCS capital cost estimates.

**DISCUSSION AND POLICY IMPLICATIONS**

In order to better understand whether flexible CCS would be an economic strategy to reduce CO2 emissions, we compared the cost effectiveness of CO2 emission reductions with flexible CCS to that of three alternative emission reduction strategies—redispachting, additional wind capacity, and normal CCS retrofits—under the CPP and a hypothetical stronger CPP. Under the CPP and stronger CPP, flexible CCS mostly achieved greater and more cost-effective emission reductions than normal CCS. Additionally, in many scenarios, flexible CCS ECCs relative to normal CCS exceeded high capital cost estimates currently available for flexible CCS. This finding in conjunction with the cost-effectiveness results indicate that flexible CCS, due to its system benefits, would be a more economic CO2 reduction strategy than normal CCS from the perspective of the power system. Thus, public policies aimed at encouraging CCS deployment should prioritize support for flexible rather than normal CCS deployment.

However, under the CPP and stronger CPP we found that flexible CCS was a less economic compliance strategy than wind, which achieved larger and more cost-effective CO2 emission reductions in most cases. Thus, under both reduction targets, wind would likely be a more common compliance strategy than CCS. The comparison between redispachting and flexible CCS is less clear. Under the CPP, redispachting achieved more cost-effective but less emission reductions than flexible CCS, whereas the opposite was true under the stronger CPP. As such, CCS and redispachting pose a trade-off between the cost and quantity of emission reductions under both targets. However, the fact that CCS proved more cost effective than redispachting only under the stronger CPP suggests CCS would be a more viable compliance strategy at higher emission reduction targets than those set forth under the CPP. Higher natural gas prices would improve the merits of CCS relative to redispachting.

Nonetheless, given the existence of the CPP, our cost-effectiveness results indicate that deployment of CCS in the midterm in our study system, the upper Midwest, will likely be limited, since at least one dominant emission reduction strategy (wind) exists. Furthermore, we find flexible CCS ECCs relative to wind and redispachting are negative or below optimistic capital cost estimates, indicating substantial capital cost reductions would be necessary for flexible CCS to be an economically competitive CO2 emission reduction strategy in the upper Midwest. We expect similar results in other regions with good wind resources, moderate CO2 emission reduction targets, and/or large spare NGCC capacity, like Texas. In regions where these conditions do not apply, e.g., the Mid-Atlantic, flexible CCS may be a cost-effective CO2 emission reduction strategy.

This research could be expanded in several ways. First, our UCED model runs in hourly time steps, but shorter time steps may capture additional value from the flexibility of flexible CCS generators and increase the value of flexible CCS relative to other compliance strategies. Similarly, directly accounting for wind forecast error could increase the value of reserves and flexible generation provided by flexible CCS. Additionally, we ignore transmission costs associated with wind deployment, which could increase wind capital costs, or transportation and storage costs and enhanced oil recovery revenues associated with CCS, which could increase or decrease CCS costs. We also do not consider space limitations at coal-fired generators that could preclude normal, or, given larger space requirements for solvent storage tanks, flexible CCS retrofits. Finally, flexible CCS may be more economic in systems with higher renewable penetration, whereas wind generates 18% of annual electricity in our test system (see SI). California, for instance, has a mandate for 33% of electricity generation by 2020. Assessing the value of flexible CCS in high renewable systems may yield markets suitable for initial flexible CCS deployment.

The CCP is one of the main components of the U.S.’s Intended Nationally Determined Contribution (INDC) submitted at the 2015 Conference of Parties 21 in Paris, but meeting the targets set forth in the INDC will likely require further emission reductions than those that would be achieved under the CPP or stronger CPP. Even if the CPP is strengthened, our analysis indicates CCS will likely play a modest role in meeting the U.S. INDC. Yet, limiting temperature rise to 2 °C would require more aggressive emission reductions than those put forth by INDCs and such reductions are likely not possible without CCS. Reconciling the poor midterm deployment prospects of CCS that we found with deployment needs to aggressively mitigate climate change will likely require public funding or other support for CCS beyond the CPP in the upper Midwest and potentially across the United States.

**ASSOCIATED CONTENT**

Supporting Information

The Supporting Information is available free of charge on the ACS Publications website at DOI: 10.1021/acs.est.6b03652.

Model formulation, additional method and data details, and supplemental results. (PDF)

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Notes

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