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Comparative Performance and Cost Assessments of Coal- and Natural-Gas-Fired Power Plants under a CO_2 Emission Performance Standard Regulation

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ABSTRACT: State and federal governments are considering performance standards to limit carbon dioxide (CO_2) emissions from new fossil-fuel-fired electric-generating units. This study employs a newly developed computational tool to compare the performance and cost impacts of applying a technology-neutral CO_2 emission performance standard to pulverized coal (PC) and natural gas combined cycle (NGCC) power plants and to evaluate the role of CO_2 utilization in accelerating carbon capture and storage (CCS) deployment. We explore the impacts of performance standards between 1000 and 300 lb of CO_2/MWh gross, a range more stringent than the recently proposed standard by the United States Environmental Protection Agency (U.S. EPA). Meeting such standards would require CO_2 emission reductions of roughly 45−85% for new PC baseload plants and 0−65% for new NGCC baseload plants. Adding current amine-based CCS to meet these standards increases the plant levelized cost of electricity by 35−66% for PC plants and 0−26% for NGCC plants. On an absolute basis, meeting the most stringent standard of 300 lb/MWh gross would add \$38.9/MWh to the cost of the PC plant but only \$16.5/MWh for the NGCC plant. This cost advantage of NGCC plants relative to PC plants is strongly affected by plant capacity factor and natural gas price and could be diminished by gas prices above approximately \$9.0/GJ for new baseload plants subject to a range of performance standards. Our analysis of the enhanced oil recovery (EOR) option shows that, at a price of roughly \$40/metric ton of CO_2, the revenue from selling the captured CO_2 for the EOR could fully offset the capture cost for PC plants. Higher CO_2 prices would be required to fully pay for CO_2 capture at NGCC plants. Using the captured CO_2 for EOR thus would facilitate continued coal use for low-carbon electricity generation, even under the most stringent performance standard modeled.

1. INTRODUCTION AND OBJECTIVES

The buildup of anthropogenic greenhouse gases (GHGs) in the atmosphere is regarded widely as the cause of most of the global warming observed over the last 50 years.[1] Abrupt changes in climate pose a serious threat to human or natural systems. To mitigate climate change, National Academies' Panel on Limiting the Magnitude of Climate Change suggests a "representative" mitigation budget that requires a significant reduction of national GHG emissions from 1990 levels by 50−80%.[2] Fossil fuel power plants are the largest stationary source of GHG emissions in the United States and account for approximately 40% of national carbon dioxide (CO_2) emissions.[3] To achieve large-scale CO_2 emission reductions for fossil fuel power plants, carbon capture and storage (CCS) is the only technology option.[4]

Currently, the cost of commercial CCS remains expensive and is a critical barrier for the CCS deployment, which would increase the plant cost of electricity by 70−80% for 90% CO_2 capture at coal-fired power plants.[5−7] The regulatory stringency of emission control requirements for sulfur oxides (SO_x) and nitrogen oxides (NO_x) has been demonstrated to drive technology innovations that reduce capital costs of flue gas desulfurization (FGD) and selective catalytic reduction (SCR) systems by more than 10% per doubling of installed capacity.[8,9] Similarly, regulatory policies that limit GHG emissions could play an important role in fostering CCS technology innovations and deployment.[8]

To mitigate climate future, state and federal governments are considering performance standards to limit CO_2 emissions from new electric power facilities. For example, the State of California has established a standard of 1100 lb of CO_2/MWh, which is similar to the emission performance of natural gas combined cycle (NGCC) power plants.[10] To cut CO_2 emissions from fossil-fuel-fired electric-generating units (EGUs), the United States Environmental Protection Agency (U.S. EPA) announced on March 27, 2012 the first rules: "The proposed requirements, which are strictly limited to new sources, would require new fossil fuel-fired EGUs greater than 25 megawatt electric (MWe) to meet an output-based standard of 1,000 pounds of CO_2 per megawatt-hour".[3] The proposed standard was established in terms of the demonstrated performance of NGCC power plants without any need for CO_2 capture. The enactment of this federal regulatory proposal would lead to a significant departure from carbon-intensive technologies and systems and then affect investments in the electricity generation sector. To meet this standard, new pulverized coal (PC) power plants have to employ CCS technology to reduce CO_2 emissions by roughly 50% to the level of NGCC power plants. However, stricter new source performance standards could include NGCC power plants in the regulation scope as well.

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Table 1. Performance and Costs of Coal- and Natural-Gas-Fired Power Plants Subject to U.S. EPA's 1000 lb of CO_2/MWh Gross EPS

category	variable	power plants with and without CCS		
parameters	EPS	no	yes/no	yes
	plant type	SC PC	NGCC	SC PC
	fuel type	Illinois no. 6 coal	natural gas	Illinois no. 6 coal
	CCS	no	no	Amine
	gross electrical output (MW)	589.7	540.9	640.1
	net electrical output (MW)	550.0	526.6	550.0
	net plant efficiency (HHV, %)	38.4	50.0	32.4
	capacity factor (%)	75	75	75
	cost basis (dollar type)	constant	constant	constant
	discount rate (%)	7.09	7.09	7.09
	fixed charge factor (fraction)	0.113	0.113	0.113
	plant life (year)	30	30	30
	fuel price ($/GJ)	1.55	6.51	1.55
	labor rate ($/h)	34.65	34.65	34.65
	CO_2 transport cost ($/ton)	0	0	2
	CO_2 storage cost ($/ton)	0	0	3
results	CO_2 removal (mass, %)	0	0	45.5
	CO_2 emission rate			
	(lb/MWh gross)	1678	782	1000
	(lb/MWh net)	1799	803	1165
	plant LCOE (2010 constant $/MWh net)	59.4	63.4	79.9
	added cost for CCS (or CCS cost) (2010 constant $/MWh net)	0	0	20.5

The CO_2-flooding enhanced oil recovery (CO_2-EOR) method has been applied to oil production and offers the potential for storing CO_2. Currently, the CO_2-EOR accounts for about 5% of domestic crude oil production in the United States.[11] Employing "new generation" CO_2-EOR technologies in domestic oil fields would offer storage capacity of more than 28 gigatons of CO_2, which is equal to the amount of CO_2 captured from 151 GW coal-fired power plants.[12] Using the CO_2 captured from fossil fuel power plants for the EOR can reduce the CO_2 capture cost while avoiding the CO_2 storage cost, despite the fact that there remain numerous issues with EOR, such as verifiable permanent storage and large-scale implementation.[13]

The major objectives of this paper are, therefore, to (1) quantify and compare the performance and cost impacts of applying a technology-neutral CO_2 emission performance standard (EPS) to PC- and natural-gas-fired baseload power plants and (2) evaluate the role of CO_2 use in accelerating CCS deployment in the context of regulating CO_2 emissions. To reach these aims, we conduct plant-level modeling to investigate a series of policy scenarios. More specifically, we start from the U.S. EPA's currently proposed standard to analyze a range of regulatory scenarios that would require CO_2 emission reductions. To meet these standards, an amine-based CCS system representing current commercial technology is employed at PC and NGCC plants when needed. We systematically estimate and compare the performance and costs for PC and NGCC plants over a range of performance standards. We particularly explore how high natural gas prices could economically facilitate the deployment of CCS at coal-fired power plants. Lastly, we quantify the role of storing CO_2 with the EOR in reducing the CCS cost. To be consistent with the U.S. EPA's proposal, the performance standards that we evaluate here are measured on the basis of the gross electrical output and also are presented in the English unit system, whereas other variables (except for CO_2 emission rates) are in the metric unit system.

2. INTEGRATED SYSTEM APPROACH

To accelerate the evaluation and development of fossil energy technology, we developed an integrated computational tool for techno-economic analysis and design of a fossil fuel power plant with CCS. The newly enhanced Integrated Environmental Control Model (IECM, version 8.0) was employed to conduct plant-level modeling for PC and NGCC power plants under the CO_2 EPS regulation. The IECM, a publicly available computer-modeling tool, was developed by Carnegie Mellon University for the U.S. Department of Energy's National Energy Technology Laboratory (DOE/NETL) to offer systematic estimates of performance, costs, and environmental emissions of fossil fuel power plants with and without CCS.[14] The model also provides the capability to characterize uncertainties of key performance and cost criteria and perform probabilistic assessments of current and advanced system designs under the common framework.[15]

The IECM applies fundamental mass and energy balances along with empirical data to formulate process performance models and further link them to engineering−economic models that estimate the capital cost, annual operating and maintenance (O&M) costs, and total levelized annual cost of an overall power plant and a variety of environmental control options.[14] The costing method and nomenclature employed in the IECM are based on the Electric Power Research Institute's (EPRI) Technical Assessment Guide (TAG).[16] Current IECM default data for PC and NGCC power plants and amine-based CCS systems were derived mainly from detailed cost studies by DOE/NETL.[6,7] The detailed performance and cost models for the IECM are available elsewhere.[17−25]

Here, the major performance metrics that we adopt for regulatory assessments are CO_2 removal efficiency and net plant efficiency [high heating value (HHV) basis], while the key cost measures are total annual levelized cost of electricity (LCOE) for an overall plant and added cost for CCS or called CCS cost. We also report the cost of CO_2 avoided, which is the most commonly used measure to quantify the average cost of avoiding a ton of atmospheric CO_2 emissions while still providing a unit of electricity to customers.[26]

We first employ the IECM to establish "base case" PC and NGCC power plants without CO_2 capture, which comply with federal New

Source Performance Standards (NSPS) for air and water pollutants. The base PC plant is configured with a supercritical (SC) boiler, while the base NGCC plant is configured with two GE 7FB gas turbines and a heat recovery steam generator. When an amine-based CO_2 capture system is installed, the stream used for sorbent regeneration is extracted from the power steam cycle for the base cases. To evaluate a range of regulatory scenarios, we determine the CO_2 removal efficiency required for each type of plant to comply with the proposed standards and further estimate the plant performance and cost. The differences in the major performance metrics and cost measures between the plants with and without CCS are used to quantify the impacts of employing CCS to meet the proposed EPS. For example, we report the CCS cost as the difference in plant LCOE between a plant with amine-based CCS and a "reference" plant without capture. In particular, we conduct sensitivity and probabilistic analyses to reveal the performance and cost impacts of major parameters under variability or uncertainty for the cases subject to the U.S. EPA's currently proposed EPS. We also undertake parametric analyses on natural gas fuel and CO_2 sale prices (when applicable) to investigate their effects on the CCS deployment. To achieve partial CO_2 capture, this study adopts the bypass design because it is a cost-effective option for non-full CO_2 control by amine-based capture systems.[27]

3. PC AND NGCC POWER PLANTS SUBJECT TO U.S. EPA'S CURRENT CO_2 EPS

In this section, we first comparatively evaluate the performance and costs of fossil fuel power plants subject to the U.S. EPA's current standard and then examine the impacts of key parameters and factors on the plant performance and costs as well as the deployment of CCS at coal-fired power plants. Table 1 presents the major technical and economic metrics defining the "base case" power plants. Table 2 gives detailed performance parameters of the amine-based capture system.

Table 2. Detailed Performance Parameters of the Amine-Based Capture System

variable	nominal value
sorbent type	Econamine FG+
sorbent concentration (wt %)	30
CO_2 removal efficiency (%)	90
maximum train CO_2 capacity (tons/h)	208.7
lean CO_2 loading (mol of CO_2/mol of sorbent)	0.19
sorbent losses (kg/ton of CO_2)	0.3
liquid/gas ratio	3.0
ammonia generation (mol of NH_3/mol of sorbent)	1.0
gas-phase pressure drop (kPa)	6.9
ID fan efficiency (%)	75
regeneration heat requirement (kJ/kg of CO_2)	3517
heat−electricity efficiency (%)	18.7
solvent pumping head (MPa)	0.207
pump efficiency (%)	75
capture system cooling duty (tons of H_2O/ton of CO_2)	92.6
CO_2 product pressure (MPa)	13.8
CO_2 compressor efficiency (%)	80

3.1. Scenarios To Meet a 30 Year Average EPS.

The performance standard proposed by U.S. EPA provides new power plants with a flexible 30 year averaging compliance option that the weighted average CO_2 emissions rate from the facility over the 30 years would be equivalent to the standard of 1000 lb of CO_2/MWh of electricity (0.454 kg/kWh) on the gross basis.[3] Thus, there are different scenarios to meet the proposed standard: a new power plant is built together with CCS at startup, or in other ways, CCS with high carbon removal capabilities is installed some years later after the new plant is built. Figure 1 shows that, when an amine-based CCS

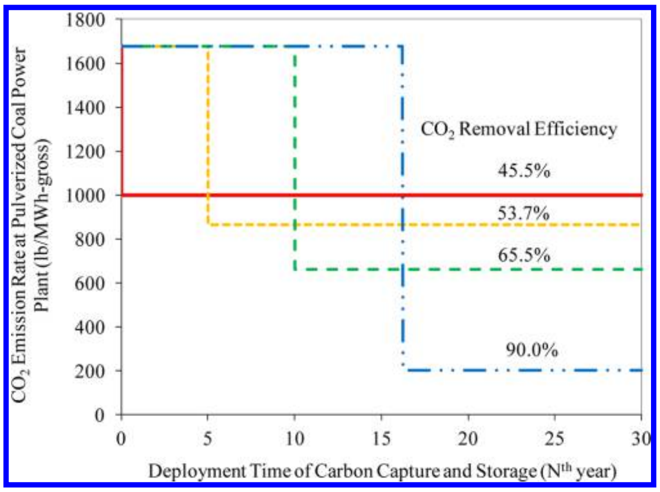

Figure 1. Feasible scenarios for PC power plants to meet the U.S. EPA's proposed 1000 lb of CO_2/MWh gross EPS on average over a 30 year period.

system is added to the illustrative supercritical PC power plant at startup, the CO_2 removal requirement is 45% over the entire 30 years and, when the capture system is added 10 years later after a new plant is built, the CO_2 removal requirement is about 65% over the rest of the 20 years. Because the maximum cost-effective removal efficiency is 90% for a typical amine-based CO_2 capture system,[27] the allowable longest waiting time for deploying CCS is about 16 years to ensure the compliance with the 30 year average standard. Beyond the 16th year, the base PC plant unlikely meets the proposed standard. In this paper, our assessments focus only on the scenario of adding CCS to a new plant at startup. This analysis does not consider potential future cost reductions (e.g., "learning by doing") over time, which are dependent upon CCS deployment scenarios.[8,28]

3.2. Performance and Cost Estimates for PC and NGCC Power Plants.

We apply the IECM to estimate the performance and costs of PC and NGCC power plants under the EPS regulation. The major results are also presented in Table 1. To comply with the proposed EPS, the base PC plant has to capture 45.5% of total CO_2 emissions on the mass basis, whereas the base NGCC plant has no need for CCS. To achieve the required partial CO_2 capture, about half of the total flue gas is bypassed at the PC plant and the rest of the flue gas enters the amine system, in which 90% of the inlet CO_2 is captured. As a result of the considerable energy requirements (e.g., steam use and electricity to power pumps, fans, and compressors) as well as a variety of capital and O&M costs for the capture system, adding CCS to the PC plant decreases the net plant efficiency from 38.4 to 32.4% and increases the plant LCOE by 34.5% from 59.4 to $79.9/MWh in 2010 constant dollars. Furthermore, the resulting cost of CO_2 avoided for the PC plant with and without partial CCS is $71/metric ton of CO_2. The PC plant with CCS has $16.5/MWh more plant LCOE than the NGCC plant without CO_2 capture.

To reduce the efficiency penalty on main power cycles, the steam used for sorbent regeneration can also be supplied by an auxiliary natural-gas-fired boiler, especially when CCS is retrofitted to existing power plants.[4] Therefore, we further investigate two alternative process designs for the capture system: an auxiliary boiler only for steam generation and an auxiliary boiler plus a secondary steam turbine for both steam and power generation. The gas-fired boiler efficiency is assumed to be 80%,[29] while the thermal efficiency of the auxiliary system for both steam and electricity generation is assumed to be 35%.[30,31] The results given in Table 3 show that, to ensure the regulatory compliance of total CO_2 emissions from the primary plant and auxiliary combustion system, the alternative case without auxiliary electricity generation has higher CO_2 removal efficiency required for the primary plant than the base case illustrated earlier because there is no control for CO_2 emissions from the auxiliary combustion system. Requiring a larger CO_2 removal efficiency for the primary plant, along with burning expensive gas fuel only for steam use, leads to more CCS cost compared to the base case using steam extracted from the main power cycle. In comparison between the alternative designs, the process for providing both steam use and auxiliary power output requires a lower CO_2 removal efficiency and appears more efficient and cost-effective because of additional power credit.

Table 3. Performance and Cost of the PC Power Plant with an Auxiliary Natural Gas Boiler under Regulation of 1000 lb/MWh Gross EPS

	auxiliary natural gas boiler (yes or no?)		
		yes	
variable	no	steam only	steam + power
gross plant power output (MW)	640.1	639.2	525.7
auxiliary power output (MW)	0	0	95.1
total gross power output (MW)	640.1	639.2	620.8
net plant power output (MW)	550.0	550.0	550.0
net plant efficiency (%)	32.4	29.7	34.1
fuel price ($/GJ)			
coal	1.55	1.55	1.55
natural gas		6.51	6.51
CO_2 removal (mass, %)	45.5	51.7	45.1
total CO_2 emission rate			
(lb/MWh gross)	1000	1000	1000
(lb/MWh net)	1165	1162	1129
plant LCOE (2010 constant $/MWh net)	79.9	92.6	85.0
added cost for CCS (2010 constant $/MWh net)	20.5	33.2	25.6

3.3. Effects of Key Parameters on Plant Performance and Cost. A sensitivity analysis was carried out for the base PC plant under the EPS regulation to investigate the effects of key parameters on CO_2 removal efficiency and added cost for CCS. When a parameter is evaluated, other parameters were held at their base case values, unless otherwise noted.

The analysis started from the two important plant design factors: plant type and coal quality.[5] The three plant types considered include subcritical, supercritical (SC), and ultra-supercritical (USC) steam generation units using Illinois no. 6 coal. The CO_2 emission rates of the three plants without CCS are 1776, 1678, and 1529 lb of CO_2/MWh gross (0.806, 0.761, and 0.694 kg/kWh), respectively. Therefore, the CO_2 removal efficiencies required to meet the EPS are different among the three plants. Panels a and b of Figure 2 show the effects of plant type on CO_2 removal requirement and added cost for CCS. As

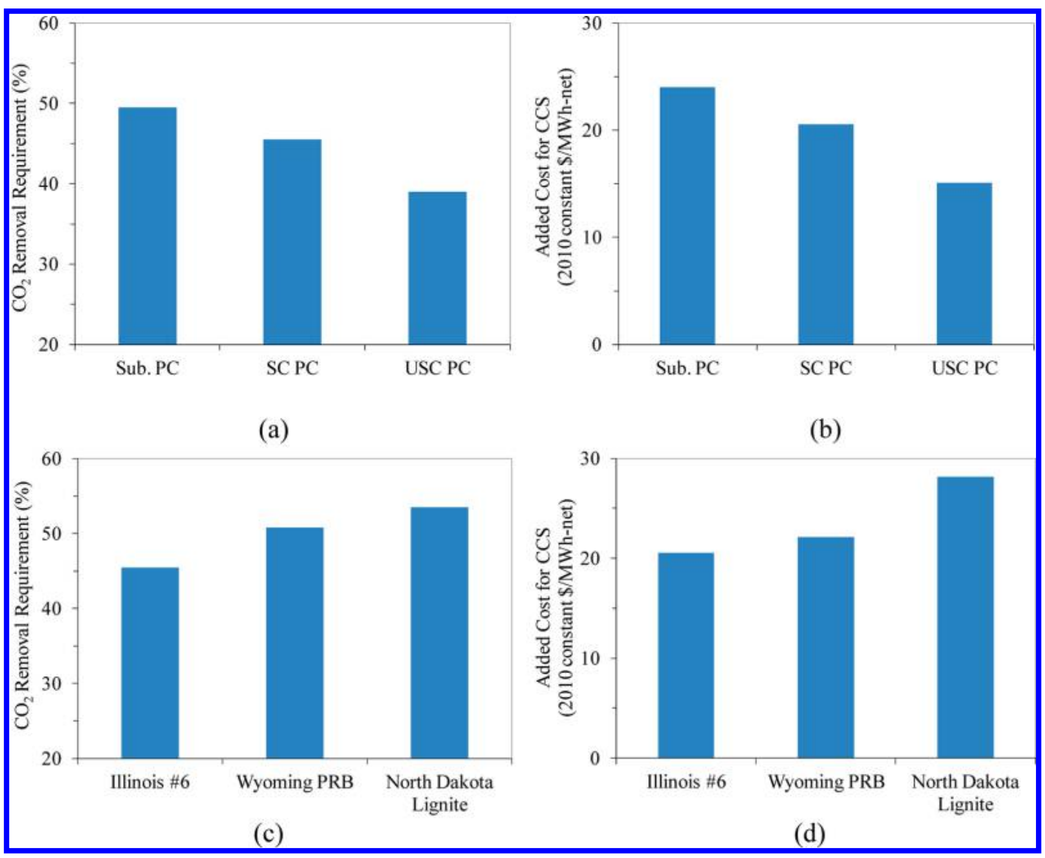

Figure 2. Variability by power plant and coal types in CO_2 removal requirement and added cost for CCS at coal-fired power plants subject to the 1000 lb of CO_2/MWh gross EPS.

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a result of improving the plant efficiency, the CO_2 removal requirements for the three plants are 49.5, 45.5, and 39.0%, respectively. In comparison to the subcritical PC plant, the SC and USC PC plants have 3.5 and \$8.9/MWh less CCS costs, respectively.

The three coal ranks considered include Illinois no. 6 bituminous coal, a Wyoming Power River Basin (PRB) sub-bituminous coal, and a North Dakota lignite coal. Table 4 summarizes coal properties in detail. For the three plants without CO_2 capture, the CO_2 emission rates are 1678, 1821, and 1905 lb of CO_2/MWh gross (0.761, 0.826, and 0.864 kg/kWh), respectively. Panels c and d of Figure 2 show the effects of complying with the proposed EPS on CO_2 removal requirement and added cost for CCS. In comparison to the base plant fired with Illinois no. 6 coal, the CO_2 removal requirement for the plant fired by North Dakota lignite increases by 8% (from 45.5 to 53.5%) and the resulting CCS cost increases by \$7.7/MWh.

Table 4. As-Fired Coal Properties

variable	Illinois no. 6	Wyoming PRB	North Dakota lignite
heating value (kJ/kg)	27140	19400	14000
carbon (%)	63.75	48.18	35.04
hydrogen (%)	4.5	3.31	2.68
oxygen (%)	6.88	11.87	11.31
chlorine (%)	0.29	0.01	0.09
sulfur (%)	2.51	0.37	1.16
nitrogen (%)	1.25	0.7	0.77
ash (%)	9.7	5.32	15.92
moisture (%)	11.12	30.24	33.03
cost (\$/ton)	42.09	9.645	16.84

We conducted additional sensitivity analysis for several major parameters related to plant utilization and economic assumptions, including the plant capacity factor (CF), fixed charge factor (FCF), CO_2 transport and storage (T&S) costs, and total indirect capital cost of the CO_2 capture system. Figure 3 shows the resulting effects on the CCS cost at the SC PC plant subject to the proposed standard. The ranges of parameter values shown in Figure 3 are based on recent studies.[5,15] Over the given parameter range, the CCS cost increases by 27, 5, and 3% in response to the changes in FCF, CO_2 T&S costs, and total indirect capital cost of the CO_2 capture system, respectively, whereas it decreases by 17% when the plant CF varies from 65 to 85%. Among the several parameters, the CF and FCF have more pronounced effects on the CCS cost.

3.4. Probabilistic Added Cost for Partial CCS at Coal-Fired Power Plants. Sensitivity analysis has only limited ability to account for the collective effects of multiple uncertain parameters and to provide likelihood information for a specific outcome.[15] To overcome these limitations, we used the probabilistic capability of the IECM to characterize the effect on the CCS cost of uncertain variables identified in the sensitivity analysis demonstrated above. Table 5 summarizes the assumed distribution functions of uncertain parameters for the base SC PC plant and CCS, referring to our recent cost study for NGCC plants.[15]

To account for the correlated variables in comparing two uncertain plants, the identical set and sequence of 500 random samples over the probabilistic simulation was assigned to the

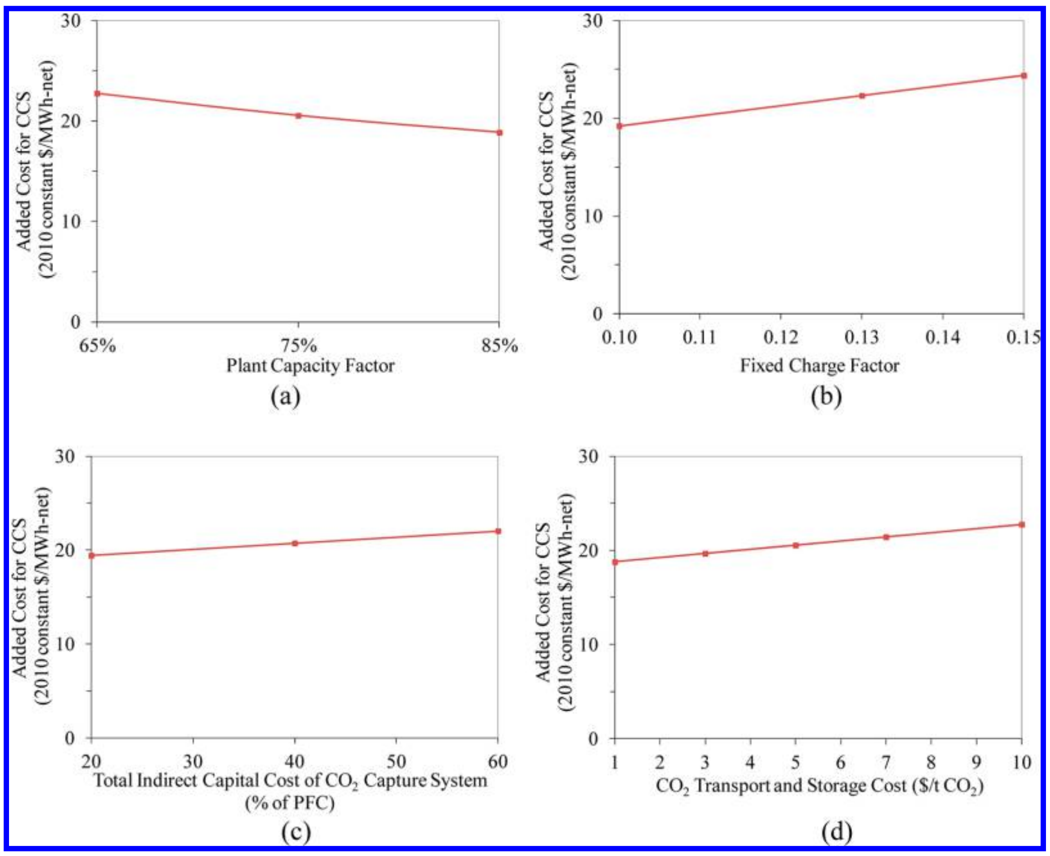

Figure 3. Effects of selected major parameters on added cost for CCS at coal-fired power plants subject to the 1000 lb of CO_2/MWh gross EPS.

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Table 5. Assumed Distributions of Uncertain Parameters for Supercritical Coal-Fired Power Plants with and without Amine-Based CCS

section	variable	nominal value	distribution function
base plant	plant capacity factor (%)	75	uniform (65, 85)
	fixed charge factor (fraction)	0.113	uniform (0.100, 0.150)
	coal cost (\$/GJ)	1.55	uniform (1.17, 1.94)
CCS	ID fan efficiency (%)	75	uniform (70, 75)
	pump efficiency (%)	75	uniform (70, 75)
	regeneration heat required (kJ/kg of CO_2)	3517	uniform (3000, 3900)
	cooling duty (tons of H_2O/ton of CO_2)	92.6	triangular (67, 92.6, 162)
	sorbent loss (kg/ton of CO_2)	0.30	triangular (0.25, 0.30, 1.55)
	solvent pumping head (MPa)	0.207	triangular (0.035, 0.207, 0.248)
	CO_2 product pressure (MPa)	13.8	uniform (12.4, 15.2)
	CO_2 compressor efficiency (%)	80	uniform (75, 85)
	total indirect capital cost (% of process facilities capital)	37	uniform (20, 60)
	miscellaneous capital cost (% of total plant investment)	2	uniform (2, 10)
	amine cost (\$/ton)	2476	uniform (2228, 2724)
	CO_2 transport cost (\$/ton of CO_2)	2	uniform (1, 5)
	CO_2 storage cost (\$/ton of CO_2)	3	uniform (1, 5)

variables common to both plants (including the plant CF, FCF, and coal cost), while independent variables for the CCS were sampled randomly.[15] We employed the established procedure of probabilistic comparative assessment to yield a distribution function for the difference in the plant LCOE between the two SC PC plants with and without CCS. The difference is the added cost for CCS installed to meet the performance standard. The detailed assessment procedure is available elsewhere.[25]

Figure 4 shows the probabilistic estimates of plant CO_2 emission rate and CCS cost. The resulting distribution of the plant CO_2 emission rate has a mean value of 1006 lb of CO_2/MWh gross (0.456 kg/kWh), which basically complies with the standard. The resulting distributions for the CCS cost have mean values of \$24/MWh and 38% on the metrics of absolute dollar and incremental cost percentage (relative to the non-capture PC plant), respectively. Their 95% confidence intervals range from 19.5 to \$29.1/MWh on the absolute dollar basis and from 33.6 to 42.6% on the percentage basis. The mean values are higher than the corresponding deterministic CCS cost given in Table 1. Given the assumed parameter distributions, the probability that the CCS cost will exceed the deterministic estimate is roughly over 90%, mainly because of the assumed non-symmetric distribution of FCF relative to the nominal deterministic value.

3.5. Effect of the Natural Gas Price on CCS Deployment at Coal-Fired Power Plants. Investing new coal- versus natural-gas-fired power plants in competition for electricity supply is influenced by gas fuel price and plant utilization. Although recent U.S. annual average natural gas prices substantially fell from the highest \$9.3/GJ (2010 dollars) in 2005, natural gas prices are projected to rise by 2.1%/year from 2010 to 2035 and to reach \$7.0/GJ (2010 dollars) on an annual average in 2035, which vary with economic growth and shale gas well recovery rates.[32] Thus, we take an outlook at how high natural gas prices could economically foster the deployment of CCS at coal-fired power plants subject to the U.S. EPA's current standard.

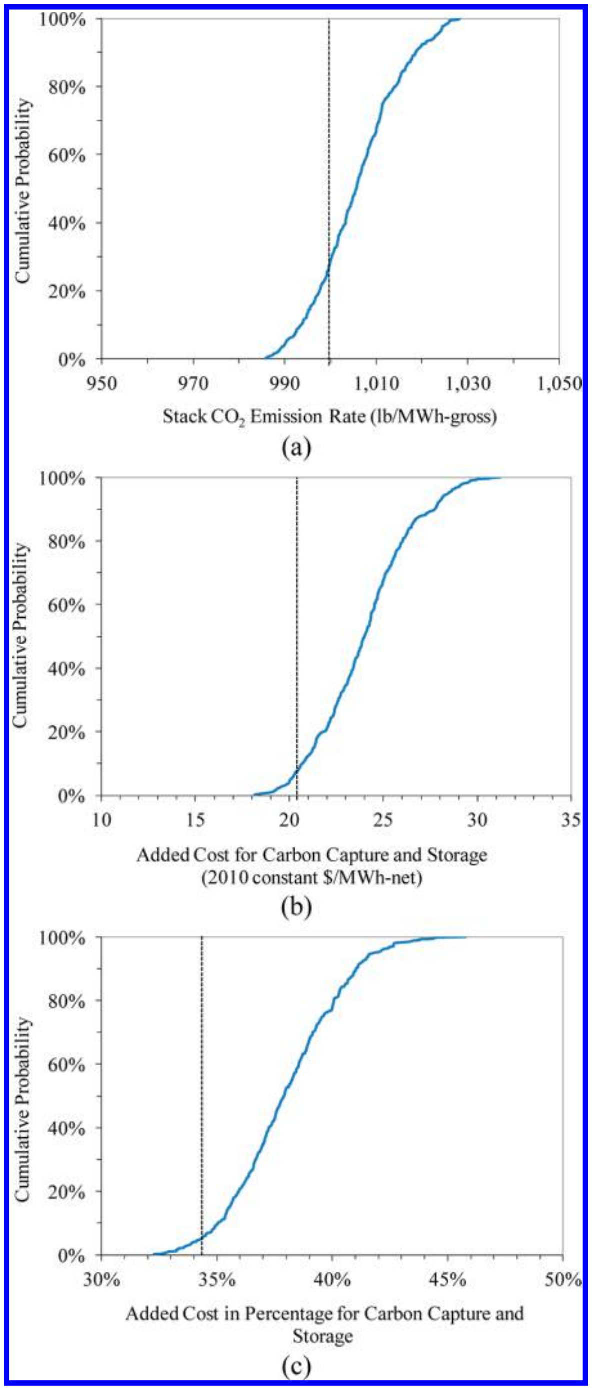

Figure 4. Probabilistic CO_2 emission rate and added cost for CCS at SC PC power plants subject to the 1000 lb of CO_2/MWh gross EPS.

Figure 5 shows the plant LCOE as a function of the natural gas price for the NGCC plant without CCS. The horizontal line shown in Figure 5 represents the cost of the base PC plant with CCS. The two cost lines intersect at a breakeven natural gas price, where both of the plants have the same LCOE. For the baseload plants given in Table 1, the breakeven gas price is about \$8.8/GJ, which is close to the aforementioned peak price.

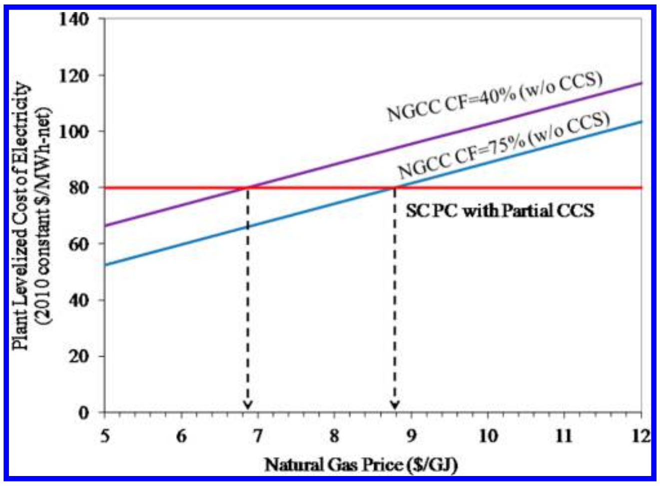

Figure 5. Breakeven natural gas price to facilitate CCS deployment at SC PC power plants subject to the 1000 lb of CO_2/MWh gross EPS.

For a natural gas price below this value, the non-capture NGCC plant has a lower LCOE than the PC plant with partial CO_2 capture. At higher natural gas prices, the capture PC plant becomes more economically attractive.

In addition to the gas price, the plant capacity factor is also a key parameter affecting the LCOE of power plants.[15] The national average capacity factors of U.S. NGCC plants increased from 40 to 50% for peak hours (from 6:00 am to 10:00 pm) and from 26 to 32% for nonpeak hours (from 10:00 pm to 6:00 am) between 2005 and 2010.[33] Although average use of the gas-fired plant fleet is rising, NGCC plants still operate at the capacity factors much less than the assumed value for new baseload plants. Thus, Figure 5 also shows the effect of a low capacity factor that represents the current national average level. The breakeven gas price decreases to $6.8/GJ when the NGCC plant capacity factor decreases from 75 to 40%. The rising of the NGCC plant use elevates the breakeven gas price.

4. PC AND NGCC POWER PLANTS SUBJECT TO MORE STRINGENT CO_2 EMISSION LIMITS

To achieve large reductions (50−80%) in U.S. GHG emissions would require the deployment of CCS at natural-gas-fired power plants to some extent.[2,34] More stringent standards than the U.S. EPA's current standard discussed above could help fulfill this requirement by limiting CO_2 emissions from NGCC plants as well. Therefore, we next evaluate stringent EPS at three levels of 300, 500, and 700 lb of CO_2/MWh gross (0.136, 0.227, and 0.318 kg/kWh).

4.1. Power Plant Performance and Added Cost for CCS. To meet the stringent performance standards, CO_2 emission reductions are required for both the PC and NGCC plants. Figure 6 shows the effects of complying with the three stringent standards on the plant performance and costs. Over the increasingly stringent standards from 700 to 300 lb of CO_2/MWh gross, the CO_2 removal efficiency required increases from 63.3 to 85.0% for the PC plant, whereas it just increases from 11.5 to 64.2% for the NGCC plant because of the reference gas plant (non-capture plant)'s lower CO_2 emission rate. As a result of adding the amine-based CCS to meet the three standards, the net plant efficiency (HHV) is decreased from 30.5 to 28.2% for the controlled PC plant and from 49.1 to 45.1% for the controlled NGCC plant and the added cost for CCS in percentage (relative to the non-capture plant) varies

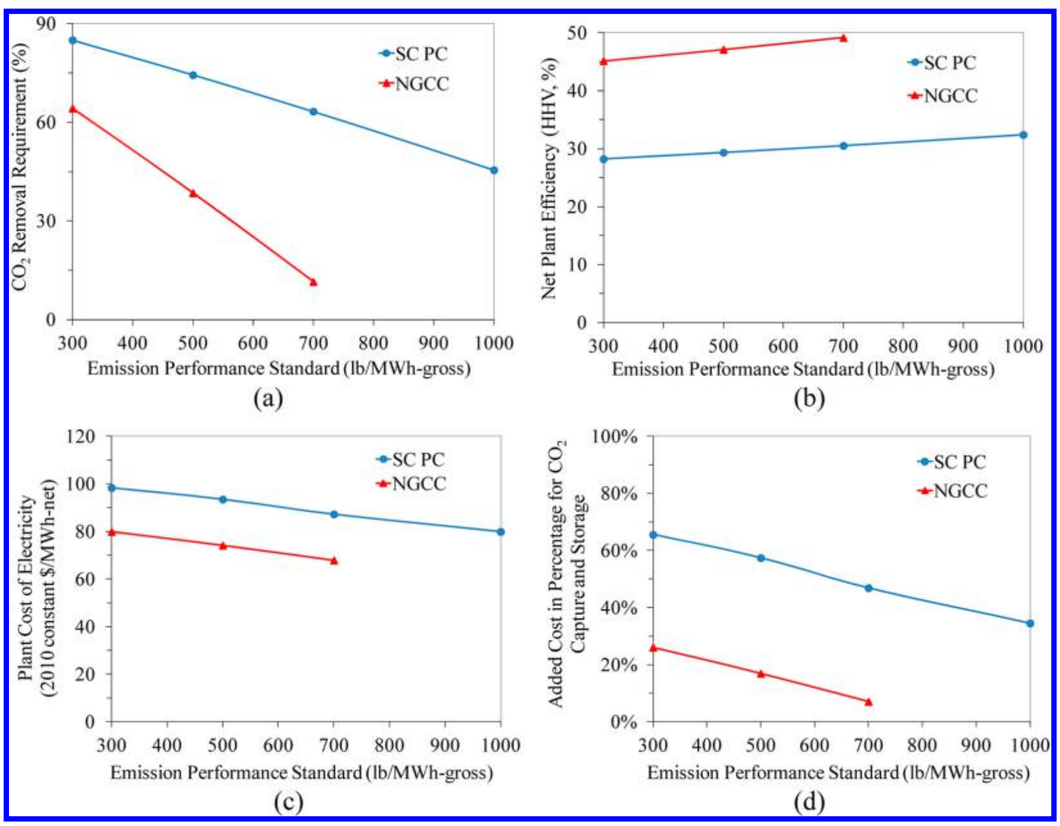

Figure 6. Performance and costs of coal- and natural-gas-fired power plants subject to stringent CO_2 EPSs.

from 46.9 to 65.5% for the PC plant and from 7.0 to 26.0% for the NGCC plant. In comparison between the PC and NGCC plants subject to the same standards, the PC CCS plant has \$23.1/MWh more CCS cost than the NGCC CCS plant on average over the three standards.

4.2. CO_2 Avoidance Cost. The cost of CO_2 avoided is an important measure for economic analysis of employing CCS to meet CO_2 performance standards, which is different from the cost of abatement that typically involves multiple CO_2 emission sources as well as changes in electricity demand.[26] The avoidance cost is also equal to the breakeven CO_2 emission tax at which the plants with and without CCS have the same LCOE, while CO_2 emissions are taxed or priced to stimulate the use of CCS.[15]

The choice of reference plant affects the estimate of CO_2 avoidance cost.[26] Figure 7a shows an illustrative NGCC plant that installs a CCS system to meet the performance standard of 500 lb of CO_2/MWh gross. When compared to the same NGCC plant without CO_2 capture, the cost of CO_2 avoided by the NGCC plant with and without CCS is \$84.5/ton of CO_2. When compared to a non-capture SC PC plant, the cost of CO_2 avoided is just \$25.4/ton of CO_2, representing the cost of carbon reductions if a NGCC plant with CCS is built in lieu of a PC plant without CCS. In this example, the difference in the incremental cost of CCS relative to the reference plant between the NGCC and PC cases is just \$4.0/MWh. In contrast, the CO_2 emission reduction shown in Figure 7a is 78% smaller for the NGCC reference plant compared to the PC reference plant. As a result, the avoidance cost based on the non-capture NGCC reference plant is much higher.

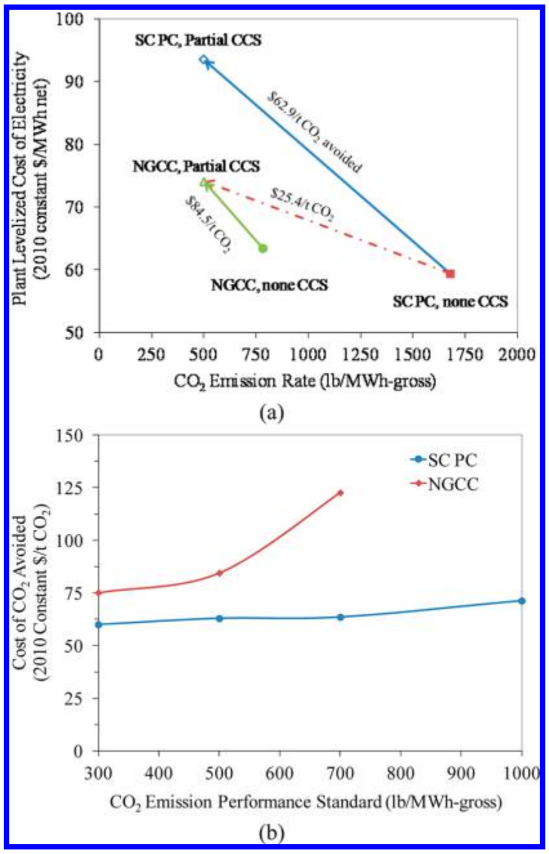

Figure 7. Costs of CO_2 avoided for meeting stringent CO_2 EPSs.

Figure 7b shows the cost of CO_2 avoided as a function of EPS for both the PC and NGCC plants. In these cases, the reference plant is identical to the capture plant in terms of plant type. The cost of CO_2 avoided shows a decreasing trend for both types of power plants when the CO_2 EPS becomes increasingly stringent. The relatively high incremental cost for a small CO_2 emission reduction (11.5%) at the NGCC plant results in the largest CO_2 avoidance cost occurring to the 700 lb of CO_2/MWh gross standard. For any given stringent standard, the cost of CO_2 avoided by the NGCC plant with and without CCS is significantly higher than that for the PC plant mainly because of the fact that the reference NGCC plant has approximately half of the CO_2 emission rate of the reference PC plant. However, the difference in the avoidance cost between the NGCC and PC plants decreases from 59 to \$15/metric ton of CO_2 when the EPS becomes increasingly stringent from 700 to 300 lb of CO_2/MWh gross.

4.3. Breakeven Natural Gas Prices. We also are interested in knowing how stringent CO_2 performance standards would influence the breakeven natural gas prices. Figure 8a shows the plant LCOE as a function of the natural gas price for the NGCC plant subject to the performance standard of 500 lb of CO_2/MWh gross. The resulting breakeven gas price is about \$9.1/GJ for the PC and NGCC

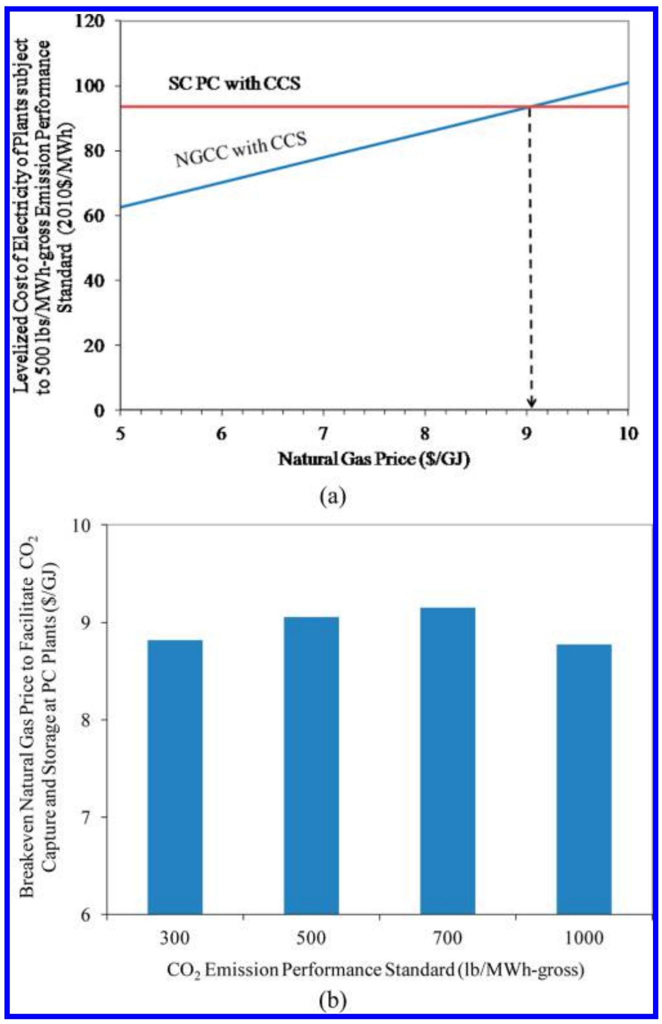

Figure 8. Breakeven natural gas prices to promote CCS deployment at PC power plants subject to stringent CO_2 EPSs.

capture plants under this standard. We did similar calculations for other standards. Figure 8b shows that, over the range of performance standards from 300 to 1000 lb of CO_2/MWh gross, the breakeven natural gas prices do not vary significantly and have a mean value of \$8.9/GJ, which is 37% higher than the gas price assumed for the baseload NGCC plant given in Table 1. This result reveals that, in comparison to natural-gas-fired power plants, coal-fired power plants with CCS become economically more attractive only under the conditions of high gas prices, no matter what the performance standard is to limit CO_2 emissions from new fossil-fuel-fired power plants.

5. ROLE OF CO_2 UTILIZATION IN ACCELERATING CCS DEPLOYMENT

The quantitative assessments performed above for a series of regulatory scenarios clearly exhibit significantly incremental costs for employing current CCS systems to meet CO_2 performance standards. To spur the commercial deployment of CCS in the context of regulating CO_2 emissions, a "simple" approach is to utilize the captured CO_2 to lower the CCS cost. To address this, we perform a parametric analysis on the CO_2 sale price to quantify the potential of CO_2-EOR in reducing the CO_2 capture cost. Although the subject of our assessment is focused on the CO_2-EOR, the relations of the incremental cost for CO_2 capture with the CO_2 sale price can definitely be referred to for other CO_2 use applications in terms of the nature of the analysis. The precondition of achievable large-scale CO_2 utilization with storage is assumed for the analysis.

In relation to the price of crude oil, the commercial CO_2 price falls roughly within the range from 25 to \$65/metric ton when the crude oil price is \$100/barrel.[35] For a lower oil price of \$70/barrel, the CO_2 price could be \$45/metric ton.[12] Therefore, our parametric analysis covers the CO_2 sale price for capture plants from 0 to \$45/metric ton of CO_2. For assessments, we first estimated the plant LCOE as a function of the CO_2 sale price for the regulated power plants with CO_2 capture and utilization (CCU). In all of these estimates, the cost of transporting CO_2 to an EOR field still was assumed to be \$2/metric ton of CO_2. However, there was no CO_2 storage cost considered any more.

5.1. Effects of CO_2-EOR on Coal-Fired Power Plants Subject to the U.S. EPA's Current Performance Standard. Figure 9 shows the effect of the CO_2 sale price on the added cost for CCU at coal-fired power plants subject to the U.S. EPA's current standard. Less than the CCS cost (\$20.5/MWh) in the base case given in Table 1, the CCU cost decreases from \$19.2/MWh when the sale CO_2 price increases from zero. At a sale CO_2 price of \$10/metric ton, equal to the tax credit for CO_2 sequestration via an EOR or natural gas recovery project,[36] the added cost for CCU is \$14.8/MWh, which is 28% less than that for the base CCS case. The CCU cost is fully offset by the revenue of CO_2 sold at the price of \$43.5/metric ton. For a sale CO_2 price above this threshold value, the PC plant with CCU has a lower LCOE than the non-capture PC plant and becomes economically attractive.

Referring to Figure 5, we also estimated the breakeven natural gas prices for the cases using the captured CO_2 for the EOR. Figure 10 summarizes as a function of the CO_2 sale price the breakeven natural gas price at which the non-capture NGCC plant has the same LCOE as the PC plant with CCU. As shown in Figure 10, using the captured CO_2 leads to noticeable reductions in the breakeven natural gas price from 8.6 to \$5.9/GJ when the CO_2 price increases from 0 to \$45/metric ton. Future natural gas prices may fall within this range in terms of the U.S. Energy Information Administration (EIA)'s projections.[32] Thus, it could be inferred that large-scale CO_2 use is beneficial to not only CO_2 capture deployment but also

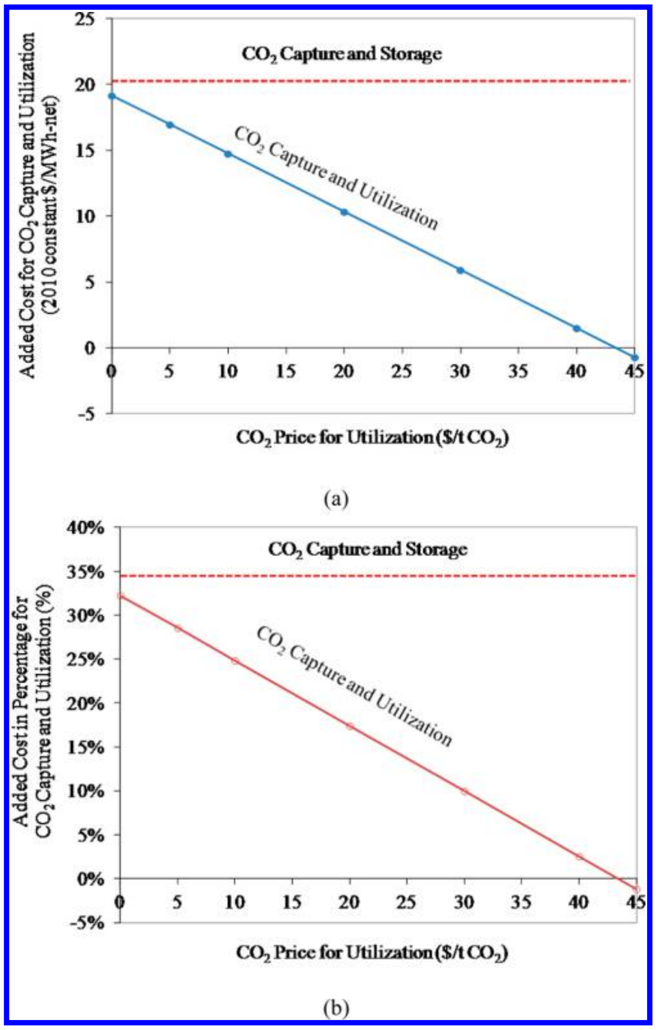

Figure 9. Effect of the CO_2 price for EOR on the added cost for CCU at PC power plants subject to the 1000 lb/MWh gross EPS.

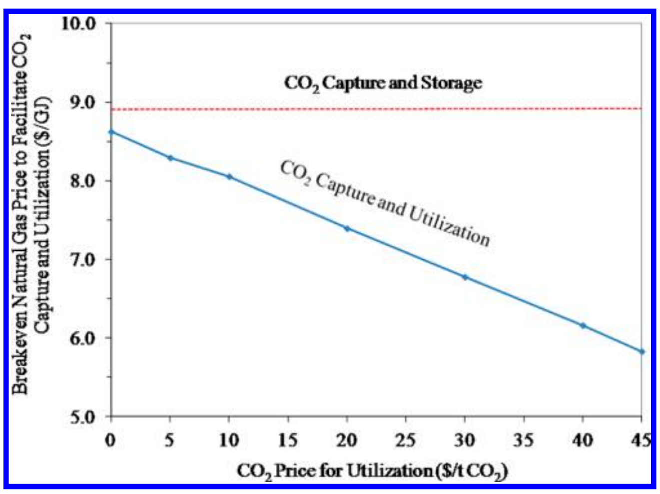

Figure 10. Effect of the CO_2 price for EOR on the breakeven natural gas price to facilitate CCU deployment at PC power plants subject to the 1000 lb/MWh gross EPS.

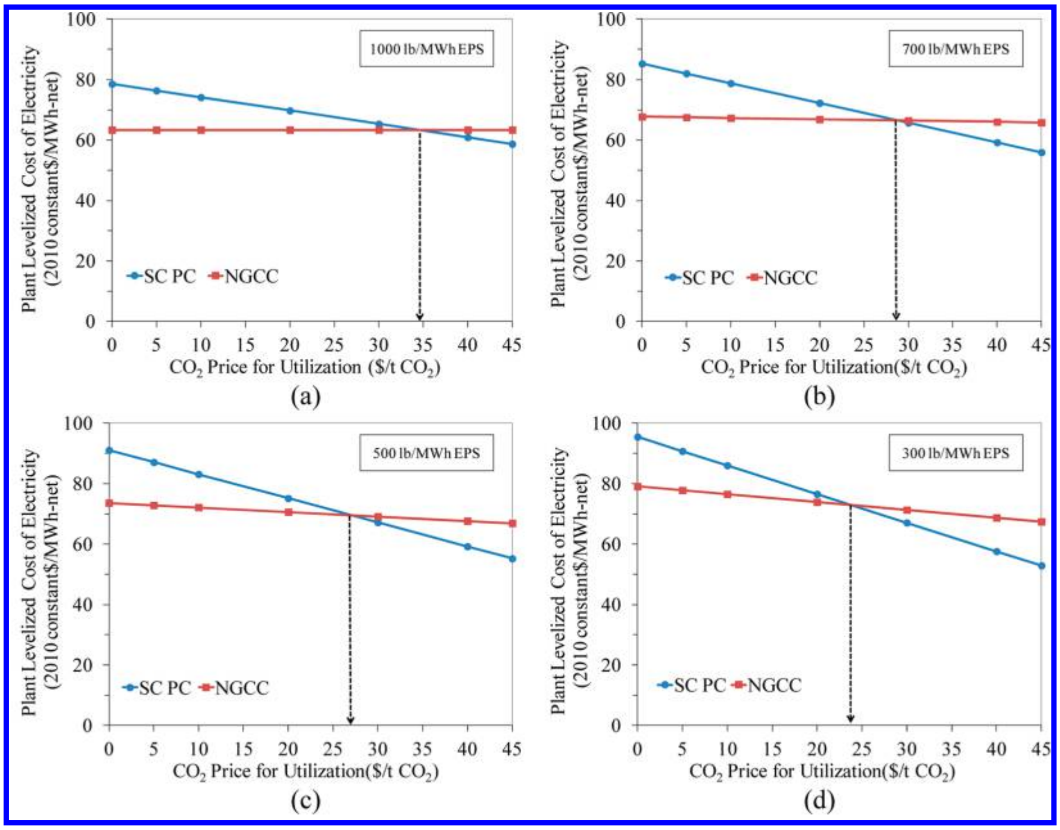

Figure 11. Costs of coal- and natural-gas-fired power plants with CCU under an EPS regulation.

continued coal use in competition with natural gas use for low-carbon electricity generation.

5.2. Effects of CO_2-EOR on Coal- and Natural-Gas-Fired Power Plants Subject to More Stringent Performance Standards. Here, we investigate the cost impacts of CO_2-EOR for coal- and natural-gas-fired power plants under the regulation of more stringent performance standards than the U.S. EPA's current proposal. Figure 11 presents the plant LCOE as a function of the CO_2 sale price for the PC and NGCC power plants with CCU, while Figure 12 shows the effects of increasing the CO_2 sale price on the added cost in percentage for CCU at the PC and NGCC plants. Obviously, the rising of the CO_2 sale price decreases the plant LCOE. In comparison to the NGCC plant, the PC plant with CCU is more sensitive to variation of the CO_2 sale price mainly because of more CO_2 emission reductions required to meet the performance standards. Around a CO_2 sale price of roughly $40/ton shown in Figure 12a, the added costs for CCU at the PC plant over the stricter standards are fully offset by the revenue from selling the captured CO_2 for the EOR. However, Figure 12b shows that, at this CO_2 price, there are still a few percentages (4−8%) of incremental cost for CO_2 capture at the regulated NGCC plant.

For any given standard, the two cost lines shown in Figure 11 intersect at a breakeven CO_2 sale price at which both the PC and NGCC plants under the EPS regulation have the same LCOE. For a CO_2 sale price above the breakeven value, the PC plant with CCU has a lower LCOE than the NGCC plant with CCU. For a CO_2 sale price smaller than this value, the NGCC plant with CCU has less plant LCOE. Figure 13 further exhibits that the breakeven CO_2 sale price decreases from 34.4 to $23.8/metric ton of CO_2 when the EPS becomes increasingly tight from 1000 to 300 lb of CO_2/MWh gross. This trend informs that, under the regulation of more stringent performance standards, just moderate commercial prices for CO_2 use could facilitate continued coal use for low-carbon electricity generation.

6. CONCLUSION

This paper has quantitatively outlined the performance and cost impacts of applying CO_2 performance standards to fossil fuel power plants. Complying with the standards from 1000 to 300 lb of CO_2/MWh gross would require CO_2 emission reductions of roughly 45−85% for new PC plants and 0−65% for new NGCC plants. As a result of employing current amine-based CCS to meet the standards, the plant LCOE is increased by 35−66% for new PC plants and by 0−26% for new NGCC plants. For coal-fired power plants, improvements in power plant efficiency and the use of high-rank coals can lower the CO_2 emission reduction requirements and associated CCS costs.

In comparison between the PC and NGCC plants subject to the same standards, the compliance of plant CO_2 emissions with performance standards results in much higher CCS costs for coal-fired power plants on an absolute basis ($/MWh), no matter where the steam used for sorbent regeneration originates. The cost advantage of gas-fired power plants could be diminished by gas prices above the breakeven price of approximately $9.0/GJ for new baseload plants subject to a range of performance standards. However, the breakeven gas price is still much higher than current gas prices and the EIA's projections. Thus, coupling CO_2 EPSs with other strategies and policies appears necessary to maintain continued investments on coal-fired power plants. The caveat on this plant-level

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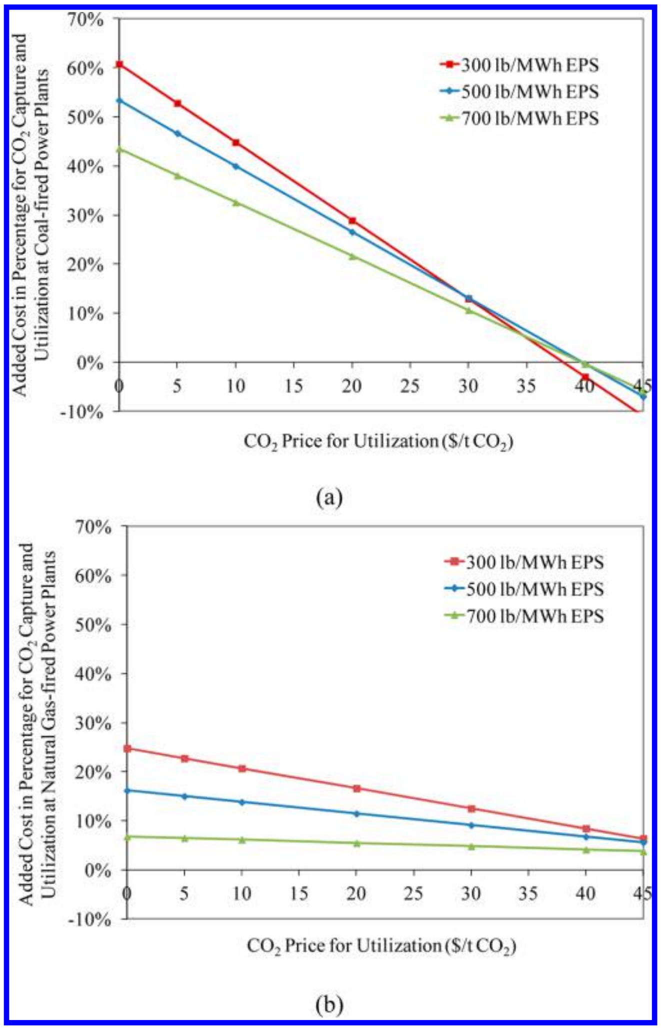

Figure 12. Effect of the CO_2 price for EOR on the incremental cost percentage for CO_2 capture and transport at PC and NGCC power plants subject to stringent EPSs.

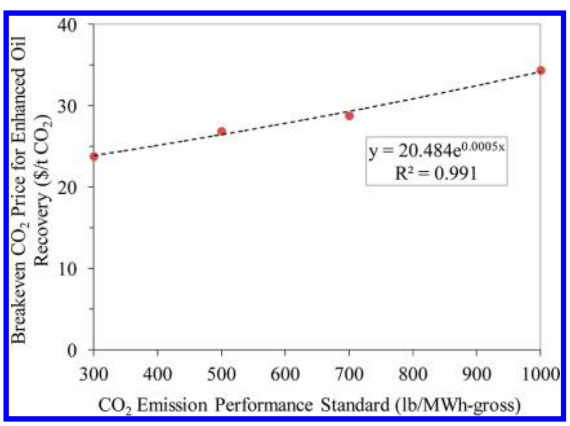

Figure 13. Breakeven CO_2 price for EOR as a function of the CO_2 EPS.

assessment is that based on historical data, the capacity factor for an NGCC plant may be not as high as assumed here for baseload plants when the gas price is sufficiently high. Lower capacity factors would increase the LCOE, making NGCC plants less attractive. A region-specific dispatch model is needed to rigorously assess the relationship between capacity factor and gas price.

When the CO_2 captured from power plants is utilized for the CO_2-EOR, at a commercial price of roughly \$40/metric ton of CO_2, the revenue from selling the captured CO_2 could fully offset the CO_2 capture cost for coal-fired power plants over the given range of performance standards. Higher CO_2 prices would be required to fully pay for CO_2 capture at NGCC plants under the regulation of stricter standards than the U.S. EPA's current standard. Because selling the CO_2 captured from coal-fired plants pronouncedly decreases the breakeven natural gas price to moderate levels, using the captured CO_2 for CO_2-EOR or other applications would facilitate continued coal use in competition with natural gas use for low-carbon electricity generation, especially in the markets that have high natural gas prices.

Our assessments reflect current commercial CCS systems and reveal significantly incremental costs incurred by the compliance with a range of CO_2 performance standards. Learning curve studies on the future cost of power plants with CO_2 capture exhibit a nearly 30% reduction in the CO_2 capture cost for new PC plants and a 40% reduction for new NGCC plants using improved technologies.[8] Here, our system analyses highlight that implementation of large-scale CO_2 utilization would offer an economically feasible platform for accelerating the CO_2 capture deployment to meet performance standards. To realize these potential cost reductions, there is a strong need for intensively supporting research and development on advanced technologies for carbon capture, utilization, and storage (CCUS). In the meantime, increasing a variety of large-scale CCUS demonstration applications would foster learning by doing to reduce CCUS costs. Energy and climate policies are drivers needed to incentivize innovations and market establishment for CCUS technologies.

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Notes

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