MULTIPOLLUTANT EFFICIENCY STANDARDS FOR ELECTRICITY PRODUCTION

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This study contains a simulation of a coal-fired electric plant subject to multiple pollutant standards for SO_2 and NO_x. It shows that firms may not choose the lowest cost technology. The firm's cost-minimizing choice is compared for three increasingly stringent standards: the 1990 Clean Air Act Amendments, the 1997 New Source Performance Standards, and the 2002 North Carolina Clean Smokestacks Act. The study finds support on cost-benefit grounds for the 2002 North Carolina standard, which is the most stringent standard, but not for the 1997 NSPS. (*JEL* Q28, Q25, L94)

I. INTRODUCTION

Federal legislation for electricity emissions has become increasingly stringent, as typified by the stricter standards of the U.S. Environmental Protection Agency's (EPA) 1997 New Source Performance Standards (NSPS) as compared to the 1990 Clean Air Act Amendments (CAAA). Electric utilities are among the firms seeking greater regulatory certainty and integrated multipollutant standards in future legislation. Electric utilities support the approach of the federally proposed Clear Skies Initiative, which presents an integrated standard for sulfur dioxide (SO_2), nitrogen oxides (NO_x), and mercury (Hg) so as to avoid "stranded capital investments from installation of controls that later become obsolete when additional regulations are promulgated."[1]

It is generally recognized that the current "piecemeal" approach, with an uncertain timetable and ratcheting of standards applied to some pollutants without considering the

1. This statement is one of several in favor of a flexible, integrated approach to environmental legislation contained in the executive summary of the Clean Skies Initiative at http://www.whitehouse.gov/news/releases/2002/02/clearskies.html. Environmentalists seek the inclusion of carbon emissions as a fourth standard, whereas the Bush administration and the electric utility industry favor restricting standards to three emissions. See Burtraw (2002) for a discussion of this debate.

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ABBREVIATIONS

CAAA: Clean Air Act
NSPS: New Source Performance Standards
NCCS: North Carolina Clean Smokestacks
SO_2: Sulfur Dioxide
NO_x: Nitrous Oxide
Hg: Mercury
PM: Particulate Matter
CO_2: Carbon Dioxide
EPA: United States Environmental Protection Agency
DOE: Department of Energy
IECM: Integrated Environmental Control Model
CMU: Carnegie Mellon University
FGD: Flue Gas Desulfurization
SCR: Selective Catalytic Removal
CuO: Copper Oxide
LNB: Low-NOx Burner
OFA: Overfire Air
SIP: State Implementation Plan
ESP: Electrostatic Precipitator
FF: Fabric Filter
S: Sulfur
LS: Low Sulfur
MS: Medium Sulfur

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relationships among pollutants, adds excessively to costs.[2] However, there is little evidence on the cost savings and net benefits from less frequent revision of standards and a more integrated multipollutant approach. This article provides such evidence of the savings to firms of crafting legislation that recognizes the relationships among multiple emissions and the advisability of foresight when emissions standards are promulgated.

In 2002, North Carolina passed the Clean Smokestacks Act, an integrated standard calling for coal-fired electric plants to reduce SO_2 by 73% by 2013 (with an interim reduction of 49% by 2009), as compared to 1998, as well as to reduce NO_x by 79% by 2009. The act requires actual reductions, so that emissions trading cannot be used to meet the new standards. This article addresses the costs and benefits of the new North Carolina integrated standard, as compared to the 1990 and 1997 federal standards. The major findings are that firms subject to the 1990 standards that must now meet the 2002 North Carolina standard choose the lowest cost method to do so. But firms that come under the 1997 NSPS choose a different method to comply with the 2002 act that results in higher costs. Results also show that net benefits are positive for the North Carolina standards, but not for the 1997 NSPS. The approach in this article can be extended to include additional emissions, including mercury (Hg), particulate matter (PM), and carbon dioxide (CO_2) emissions.[3]

The method used in this article is a detailed simulation of a single coal-fired electric generating plant. Electricity production uses the Integrated Environmental Control Model (IECM), developed by Rubin, Berkenpas, and others at Carnegie Mellon University (CMU) with support from the Department of Energy (DOE) and applied in a series of papers (Rubin et al., 1997, 2001, among others). The IECM is a detailed engineering model of electricity production, including the associated multiple emissions as well as the corresponding production costs.

The IECM can simulate both traditional production, aimed at reducing a single emission, and integrated methods that target multiple emissions. Utilities limiting SO_2 emissions have switched to low-sulfur coals and added flue gas desulfurization (FGD) scrubbers. To limit NO_x, utilities have incorporated low-NO_x burners and selective catalytic removal (SCR). This article focuses on the costs of complying with environmental controls for SO_2 and NO_x, and the possibility that utilities subject to increasingly stringent controls may choose a solution with higher costs than if they had known the later standards at the time when they chose the compliance strategy to meet the initial standard. The IECM contains several integrated technologies that are under development. The most promising from a cost standpoint appears to be the fluidized bed copper oxide (CuO) process. To the extent that regulations encompassed multiple pollutants in a predictable fashion, it is likely that firms would be more willing to invest in research and development (R&D) in integrated technology, leading to earlier development.

II. LITERATURE

Through the use of the IECM, Rubin and others have examined a variety of multipollutant issues. They have looked at the cost savings of a multipollutant approach attributable to the use of advanced integrated technology as compared to traditional separate technologies. For example, a fluidized bed CuO process is an advanced integrated technology under development at the DOE that can reduce both SO_2 and NO_x. The traditional approach is FGD to meet stringent sulfur restrictions and SCR to meet NO_x restrictions. A firm subject to one regulated emission could initially install the single emission technology and then add the second technology when it faces an additional regulated emission. If it knew both constraints at the outset, it would have an increased motivation for choosing the integrated technology.

There is relatively limited economics literature on multiple pollutants, and only a subset of that literature considers the efficiency of

2. For a recent statement of this suggested policy reform, see Burtraw and Palmer (2004).

3. Were the North Carolina legislation to allow emissions trading, firms could attain the more stringent goals at a lower cost. Trading would give the option of not upgrading to meet the more stringent standard, while firms that can meet the new standard at a lower cost could reduce emissions and sell permits. Even so, overall cost would not necessarily be minimized, as firm decisions would depend on their existing technologies to meet earlier standards. This article does not consider trading, given that firms cannot use emissions trading to achieve the North Carolina goal.

multipollutant standards.[4] Eskeland (1997) evaluates a package of programs to reduce multiple air pollutants in Santiago, Chile. The author uses a four-step benefit estimation approach. The steps are to measure the reduction in emissions brought about by the programs, to translate those reductions into reduced mortality and morbidity, to value those reductions in dollar terms, and to calculate those benefits on a dollar per ton basis. Finally, benefits and costs are compared, with the finding that the overall program, as well as each part of the program, passes the benefits/costs test.

Eskeland contrasts that result with Krupnick and Portney (1991), who found that for the United States, improvements in air quality mandated by the 1990 CAAA have costs that outweigh benefits on the order of 10:1. That article focused primarily on a single emission, volatile organic compounds (VOCs), and secondarily on particulates. Additional studies have challenged this finding, including the Office of Radiation Analysis (EPA). The EPA study (1999b) includes six emissions, and finds benefits outweigh costs on the order of 4:1.

Austin et al. (1998) estimate benefits to Maryland from Title IV of the 1990 CAAA, which addressed both SO_2 specifically and NO_x more generally. The amendments introduced emissions trading for sulfur, with two phases of emission reductions. It introduced a more traditional approach for reducing NO_x emissions. Since that time, the NO_x state implementation plan (SIP) has introduced a separate standard during the five-month peak ozone season. Plants can meet this standard based on an average level of emissions, rather than a plant-specific level, and 22 eastern states have begun to implement NO_x trading programs. California has a separate program, known as RECLAIM, for NO_x control.

Burtraw et al. (2001) examine cost-effective reduction of NO_x emissions from electricity generation, simulating reductions from a summer season regional approach to NO_x trading, as is currently under way, an annual regional approach, and an annual national approach. While the article concentrates on a single emission, there is consideration of the extra cost to utilities if they plan for a seasonal emissions program and are then "surprised" by a change to an annual program. This sequential change of standards is another application of the "piecemeal" approach, as compared to an integrated standard where the initial requirements do not change within a period specified by the legislation.

Other studies have taken a macrolevel view of the effects of integrated standards on emissions and electric costs. A study by the Energy Information Administration (EIA, 2001) within the Department of Energy looks at how proposed multipollutant standards would affect emissions and electricity costs forecasted to 2020. They consider a variety of technologies. However, these technologies are conventional insofar as each targets a single emission, with additional technologies inserted to target additional emissions. They do not examine cost savings that could come from less frequent changing of standards, regulatory cognizance of relationships among emissions, or using integrated technologies. One of the reasons for integrated standards is that utilities will then choose integrated technologies instead of add-ons.

The Office of Air and Radiation within the EPA (1999a) examined multiple emissions reductions that would result from controls on single emissions including SO_2, CO_2, Hg, and multiple emissions of SO_2/CO_2 and SO_2/CO_2/Hg. They use a macroview to predict economy-wide costs from legislation and find savings from a multipollutant legislative approach.

Banzhaf et al. (2002) link together several models to determine efficient fees and corresponding quantities for SO_2 and NO_x emissions at an aggregate U.S. level. They find that the levels of emissions proposed in both the Clear Skies Initiative and an alternative proposed by Jeffers are in the proximity of efficient emissions levels. Their results are based on conventional approaches and technologies aimed at single emissions, such as the use of low-sulfur coal, scrubbers, low-NO_x burners, and catalytic converters. Their aggregate approach also considers fuel switching (from

4. Other articles with multipollutant aspects include a paper by Montero (2001) that models marketable permit systems for multipollutant markets by introducing an exchange rate between permits. Two articles correct for multiple emissions in measuring electric utility productivity [see Faere et al. (1989) and Yaisawarng and Klein (1994)]. A book by Dhanda et al. (1999) develops a network approach to modeling markets with single and multiple emissions. They use simulations to evaluate how emissions affect emissions trading prices and quantities, as well as output prices and quantities. Maranas and Gupta (2003) are developing a simulation of electricity production that includes emissions trading.

TABLE 1
Selected IECM SO_2 and NO_x Control Options for a Coal-Fired Plant

<table>
<tr><th rowspan="2">Pollutant Control</th><th colspan="2">Targeted Emission</th></tr>
<tr><th>Sulfur (SO2)</th><th>Nitrogen (NOx)</th></tr>
<tr><td>Precombustion</td><td>Coal type (i.e., low-sulfur coal)</td><td></td></tr>
<tr><td>Combustion</td><td></td><td>In-furnace control (i.e., low-NOx burner (LNB))</td></tr>
<tr><td>Postcombustion</td><td>Scrubber (i.e., flue gas desulfurization (FGD))</td><td>Catalytic converter (i.e., hot-side selective catalytic removal (SCR))</td></tr>
<tr><td></td><td colspan="2">Integrated technology (i.e., fluidized bed copper oxide (CuO) process)</td></tr>
</table>

coal to natural gas) and reduced demand and conservation.

The current article focuses on a utility using a single coal-burning power plant that can use either conventional technologies aimed at a single emission or innovative technologies geared toward multiple emissions.[5] The primary purpose is to consider the circumstances where utilities will choose a technology that results in excessive costs. The secondary purpose is to compare the costs to the benefits of an increasingly stringent standard, culminating with the 2002 North Carolina Clean Smokestacks Act (NCCSA). The legislation is aimed at existing coal plants and freezes rates for five years. Thus it is possible to focus on the lowest cost technology, and it is not necessary to consider fuel switching or electricity demand and conservation.

III. IECM ANALYSIS OF SO_2 AND NO_X EMISSIONS

Table 1 contains the IECM options directly relevant to a coal-fired electric plant subject to restrictions on SO_2 and NO_x. Technology aimed at a single emission may increase or decrease other emissions. Rubin et al. (1997) show, for example, that low-sulfur coal reduces SO_2, but increases NO_x, PM, and Hg. These secondary effects should be considered when evaluating the desirability of a single-emissions approach. Furthermore, the cost of meeting additional requirements, such as for NO_x, depends on the previous technology decision. If a switch from medium to low-sulfur coal increases NO_x emissions and a NO_x requirement is added, it will be necessary to use a larger size SCR to reduce NO_x to the required level than if there had been no secondary effect.

Options to control other emissions may be indirectly relevant. For example, a facility subject to particulate restrictions may choose a particulate control technology that affects other emissions, as well as affecting other emissions technologies. Electrostatic precipitators (ESPs) and fabric filters (FFs), among the technologies to control particulates, affect SO_2 and NO_x emissions directly as well as indirectly through effects on SO_2 and NO_x technologies. Also, there are options regarding the disposal of solid wastes, such as mixed with landfill or with bottom ash, that can affect other emissions.

The modern era of pollution control began with Title IV of the 1990 CAAA, which introduced sulfur emissions trading and capped sulfur emissions by approximately half, as compared to 1980. Phase I began in 1995, with the largest electric utility plants constraining sulfur emissions to 2.5 lb/MBtu (10^6 or 1 million Btu). Phase 2 expanded coverage to smaller plants in the year 2000, and a reduction to 1.2 lb/MBtu.[6] The legislation took a more

5. There is a dissertation in progress by Echeverri that uses the IECM along with decision techniques to measure the cost of regulatory uncertainty for a coal-fired power plant by estimating the value of having perfect information.

6. There are a variety of units used to express constraints, including tons per year and pounds per megawatt (lb/mW). The IECM expresses emissions constraints in pound per million Btu, which relates emissions to the fuel input, in this case the input of coal. This article uses the notation MBtu throughout. Equivalent notations that are used elsewhere are mmBTU and MMBtu.

Using lb/mW relates emissions to the electricity output. There is discussion that constraints in pounds per megawatt-hour (lb/mWh) of electricity output would lead to more efficient behavior than lb/mmBtu of fuel input. Currently firms have an incentive to minimize emissions per unit of fuel input, but not necessarily to minimize fuel input use. Defining the constraint in units of output would provide an incentive to minimize fuel inputs.

conventional approach to NO_x, initially requiring plant-specific reduced emissions. While no caps were placed on NO_x, the first phase of NO_x controls reduced emissions to 0.45 or 0.5 lb/MBtu, depending on the boiler technology in place, primarily affecting the same plants as were subject to the initial SO_2 controls. In 1999 the EPA passed the NOx SIP, with additional requirements for the summer ozone season for 22 eastern states, but these requirements allowed firms to meet NO_x requirements based on average plant emissions, rather than at each plant. California and the East have begun NO_x trading programs. An integrated approach would have established these options at the outset. The piecemeal approach to NO_x regulations may have resulted in firms undertaking plant-specific reductions that were more costly than achieving average emissions standards, or being able to buy and sell emissions permits.

In addition to meeting Title IV of the CAAA, upgrades of plants may trigger more stringent standards as embodied in the NSPS, depending on cases now being litigated. For plants modified after July 9, 1997, that trigger NSPS, SO_2 cannot exceed 1.2 lb/MBtu and the emission limit for NO_x is 0.15 lb/MBtu.[7] Finally, states are allowed to pass standards that are stricter than the federal standards. The North Carolina act translates to 0.16 lb/MBtu for sulfur and 0.07–0.10 lb/MBtu for NO_x.[8]

A. Cost of Meeting the 1990 CAAA and 1997 NSPS

The conventional approach of multiple air pollution control by coal-fired power plants is to use separate technologies for each pollutant (Rubin et al., 1997). For example, utilities may use an in-furnace control (low-NO_x burner) plus a hot-side SCR system and a wet FGD to separately control NO_x and SO_2. These technologies can reduce emissions by 90% or more. However, the fluidized bed CuO process currently under development at DOE can remove at least 90% of SO_2 and NO_x emissions in a single system. The cost of a nonintegrated approach is that firms might not choose the integrated process even if it could achieve the current standard at a lower cost because they have already installed separate technologies to meet the earlier standard. They are also less likely to invest in R&D for integrated technologies. We compare these two approaches using the IECM simulation, on the premise that the cost of a commercially available CuO system will be comparable to the development model.

The basic production parameter settings for both approaches include (1) annual 500 megawatt gross (mW gross) production, (2) capacity factor set at 75% (on average, production is at 75% of plant capacity, (3) 90% removal rate for both SO_2 and NO_x emissions, (4) the particulates control technology is required to be set at 0.03 lb/MBtu by the federal standard, (5) solid wastes are disposed of in a landfill, (6) 90% mercury removal, required to meet the 1990 CAAA, and (7) no CO_2 removal, reflecting the absence of such standards at the current time.

The IECM also provides costs corresponding to production. The cost calculations contain detailed formulas for base plant and emission control technologies (see Berkenpas et al., 1999). The model also contains parameters that would be needed in the capital asset pricing model (CAPM), such as the amount of debt and equity, including preferred versus common stock, corresponding anticipated returns to stockholders, and plant lifetime for depreciation purposes.

The results of the IECM simulation are summarized in Table 2 for the 1990 CAAA and 1997 NSPS. Simulations are presented for conventional and integrated technologies, and for two coal types—Appalachian low and medium sulfur. The base technology for all cases includes a low-NO_x burner with overfire air (LNB and OFA). Base particulate control is a cold-side ESP for conventional technologies and jet-pulse FF for integrated technologies. The table contains the revenue requirement needed to recover cost (on a $/mWh-net basis) and the portion attributable to emission control costs. Total cost contains the cost of the base plant plus the cost of emissions technology. Coal costs are contained

7. As of May 2004, the NO_x standard for the eastern states participating in NO_x trading is 0.15 lb/MBtu.

8. These numbers were provided as general guidelines by Mike Stroben, Manager, EHS Technical Analysis, Corporate Environmental Health and Safety, Duke Energy Company. The lower NO_x figure is for a tangentially fired boiler, the default option for the IECM. The higher figure is for a wall-fired boiler. The actual number will be different at every facility, depending upon facility type, boiler technology, and coal type.

TABLE 2

Cost of Production Alternatives to Comply with 1990 CAAA and 1997 NSPS

Coal Type (LS, MS) + Technology (FGD, SCR, CuO, NO_xSO)		Revenue Requirement ($/mWh)	Emission Cost ($/mWh)
MS (Base Case)	1990 CAAA	N/A (S > 2.5 lb/MBtu)	
	1997 NSPS	N/A (S, NO_x > lb/MBtu)	
LS (Base Case)	**1990 CAAA**	**$38.21**	**$1.888**
	1997 NSPS	N/A (NO_x > 0.15 lb/MBtu)	
MS + FGD	1990 CAAA	$42.33	$7.085
	1997 NSPS	N/A (NO_x > 0.15 lb/MBtu)	
LS + FGD	1990 CAAA	$45.81	$7.923*
	1997 NSPS	$47.37	$9.304
MS + SCR	1990 CAAA	$42.33	$7.085
	1997 NSPS	N/A (S > 2.5 lb/MBtu)	
LS + SCR	1990 CAAA	$39.68	$3.165
	1997 NSPS	**$39.74**	**$3.226**
MS + SCR + FGD	1990 CAAA	$43.96	$8.517
	1997 NSPS	$44.31	$8.868
LS + SCR + FGD	1990 CAAA	$47.31	$9.248*
	1997 NSPS	$47.37	$9.304
MS + CuO	1990 CAAA	$39.53	$5.048
	1997 NSPS	$41.83	$7.311
LS + CuO	1990 CAAA	N/A (floating point error)	
	1997 NSPS	N/A (floating point error)	
MS + NO_xSO	1990 CAAA	N/A (floating point error)	
	1997 NSPS	$46.53	$11.55
LS + NO_xSO	1990 CAAA	$45.62	$8.502*

Production method with lowest total cost is in **bold**.

Asterisk (*) indicates that method exceeds emissions standard.

Amounts are in constant 1999 dollars.

Revenue requirement is amount needed per mWh to recoup cost.

CAAA emissions standards are 2.5 lb/MBtu SO_2 and 0.45 lb/MBtu NO_x. NSPS 1997 emissions standards are 1.2 lb/MBtu SO_2 and 0.15 lb/MBtu NO_x.

A floating point error occurs when a calculation involves dividing by zero.

in the base plant costs.[9] The unit of $/mWh-net reflects the cost of production per net megawatt-hour of electricity produced. The net measure indicates electricity produced minus electricity used to run the technology.

The lowest cost method to meet the scenario of reducing both SO_2 and NO_x by 90% while meeting the 1990 CAAA particulates standard of 0.03 lb/MBtu is the base case with low-sulfur coal. Low-sulfur coal is sufficient to meet the emissions constraint of 2.5 lb/MBtu, while a low-NO_x burner reduces NO_x enough to meet 0.45 lb/MBtu. The use of medium-sulfur coal resulted in 3.1 lb/MBtu in the base case, exceeding the emissions constraint. For the 1990 CAAA, Appalachian low-sulfur coal produced a lower cost than any of the other six coal options. In scenarios reflecting more stringent standards, Appalachian low-sulfur and medium-sulfur coal were the options considered.

An asterisk next to a subtotal indicates that the emissions technology reduced sulfur emissions considerably below the required level. Had the firm known with certainty that SO_2 or NO_x standards would be further reduced at a future time, the firm could have evaluated whether to adopt the more expensive technology then rather than alter the lower cost, higher emitting technology when a new regulation begins. The second integrated

9. There are cases where the utility chooses a higher-cost emissions technology, yet the revenue requirement increases by less than the emissions cost. These two figures can increase by different amounts when the base plant costs decrease while emissions costs increase. One reason is that the firm has switched to a lower-cost coal, a part of base plant costs, while switching to a more expensive emissions technology. A second reason, mentioned earlier in the article, is that the size of the needed technology can change.

TABLE 3
Tightening Either NO_x, SO_2, or Both Emissions: 2002 NCCSA Standard

Coal Type (LS, MS) + Technology (FGD, SCR, CuO, NO_xSO)		Revenue Requirement ($/mWh)	Emission Cost ($/mWh)
LS + SCR	**NO_x lower**	**$40.08**	**$3.560**
	SO_2 lower	N/A (S > 0.16 lb/MBtu)	
	NOx lower, SO_2 lower	N/A (S, NO_x > allowed lb/MBtu)	
MS + SCR + FGD	NO_x lower	$44.46	$9.215
	SO_2 lower	$44.97	$9.406
	NO_x lower, SO_2 lower	$45.26	$9.716
LS + SCR + FGD	NO_x lower	$47.65	$9.613
	SO_2 lower	$46.07	$8.545
	NO_x lower, SO_2 lower	$46.41	$8.883
MS + CuO	NO_x lower	$41.86	$7.349
	SO_2 lower	$43.32	$8.588
	NO_x lower, SO_2 lower	$43.34	$8.610
LS + CuO	NO_x lower	N/A(floating point error)	
	SO_2 lower	**$42.73**	**$6.002**
	NO_x lower, SO_2 lower	**$42.75**	**$7.097**

Only technologies that can achieve emissions constraints are shown.
NO_xSO is omitted because it is higher cost than CuO.
The lowest cost method is in **bold**.
Amounts are in constant 1999 dollars.
NCCSA 2002 emissions standards are 0.16 lb/MBtu SO_2 and 0.07 lb/MBtu NO_x.
Revenue requirement is the amount needed per mWh to recoup cost.
A floating point error occurs when a calculation involves dividing by zero.

technology under development at DOE, simply called NO_xSO, allows the firm to exceed the standard by a considerable margin.

In order to meet the more stringent NSPS restrictions, the lowest cost solution is to add NO_x catalytic control (SCR) while continuing to use low-sulfur coal. It is no longer possible to achieve the emissions constraint using low-sulfur coal and the base case configuration. The incremental cost of meeting the more stringent NSPS is $1.53/mWh-net ($39.74–$38.21).

Again, if a firm knew that sulfur emissions would be further constrained in the future, the firm would consider adopting an integrated technology. By making the decision to use the NO_x technology, the firm will be more likely to add a scrubber (wet FGD) to reduce sulfur in response to a tighter sulfur constraint in the future, such as the standard of the NCCSA. The results suggest that the integrated CuO technology is likely to be able to control both NO_x and SO_2 at a lower cost.

B. *Cost of Meeting the NCCSA*

North Carolina coal-fired electric plants are now evaluating technologies to achieve the more stringent requirements of the NCCSA. The North Carolina legislation translates to reduced SO_2 emissions of 0.16 lb/MBtu by 2013 and reduced NO_x emissions of 0.07/lb/MBtu by 2009.

Before considering the simultaneous tightening of both SO_2 and NO_x, suppose North Carolina had tightened one standard, while leaving the other unchanged. Consider a firm that initially met the NSPS, but now must meet the tighter NCCSA standard for either SO_2 or NO_x. Table 3 shows the costs for the tighter NO_x standard first, while not changing the NSPS SO_2 standard, followed by the NCCSA SO_2 standard, while maintaining the NSPS NO_x standard. Finally, the table shows the costs if both standards are tightened.

If the NCCSA tightened NO_x emissions only, as compared to NSPS, the lowest cost technology is SCR with low-sulfur coal, which was also the lowest cost technology to meet NSPS. The additional cost of meeting the tighter NO_x constraint is $0.34/mWh ($40.08–$39.74). As was the case if a firm had to adapt to NSPS from CAAA, the lowest cost solution is to install SCR.

Alternatively, if only sulfur emissions are tightened, the firm cannot meet the new emissions standard without sulfur technology. The only feasible solutions are to install FGD as well as SCR, or use an integrated technology. A firm building a new plant would find the integrated CuO technology to be the lowest cost.

A firm meeting the 1990 CAAA, but not required to meet NSPS, would also install CuO technology, since it had not previously installed any emissions technology. But a firm that was subject to NSPS would have already installed SCR. For this firm, adding FGD would be cheaper than the integrated solution. Cost increases by $5.23/mWh ($44.97–$39.74), as compared to scrapping SCR and installing CuO technology at a cost of approximately $6.00.

Similarly, if North Carolina had tightened NO_x first, followed by SO_2, a utility would find it costs less to add FGD than to scrap SCR and install CuO technology. Yet the lowest cost method of achieving the dual standards is CuO technology. Had North Carolina tightened the SO_2 standard first, followed by NO_x, there would be no such conflict. The integrated CuO technology is the lowest cost solution for both of these cases. Again, it should be noted that a firm subject to the 1990 CAAA standards would also choose CuO technology, while a firm that complied with the 1997 NSPS by installing SCR would find it less costly to add FGD to meet the 2002 standard, even though CuO technology would be the lowest cost solution if the firm had not installed an SCR.

In the United States, firms needing to meet stringent SO_2 requirements have looked toward scrubbers (FGDs). To meet stringent NO_x standards, they have generally considered the installation of catalytic converters (SCRs).[10] This technology combination is denoted by "separated" technology. Typically firms installed FGD to meet the year 2000 sulfur standard of the 1990 CAAA. For firms that were subject to the NSPS, they have also added an SCR. For this sequential technology, costs are lower with Appalachian medium-sulfur coal than with low-sulfur coal.

Cost figures for the fluidized bed CuO process are from DOE research, which developed the process at its Federal Energy Technology Center in conjunction with, among others, Carnegie Mellon University. The cost difference, including the base plant (coal, boiler, ash disposal, etc.), is approximately $2.50, approximately 6% of the total cost of producing 1 mWh. The emission control cost of the CuO system is $7.10, considerably lower than the separate controls. Compared to separate controls with low-sulfur coal, the difference is $1.73, more than 20% less.

Proponents of long-term, multipollutant legislation use this argument to suggest the savings from a multipollutant approach. In order for firms to use the lowest cost technology, controls will have to be long term and stable. Environmental legislation needs to consider that in complying with one standard there are changes in other effluents, as well as changes in the cost of complying with future standards.

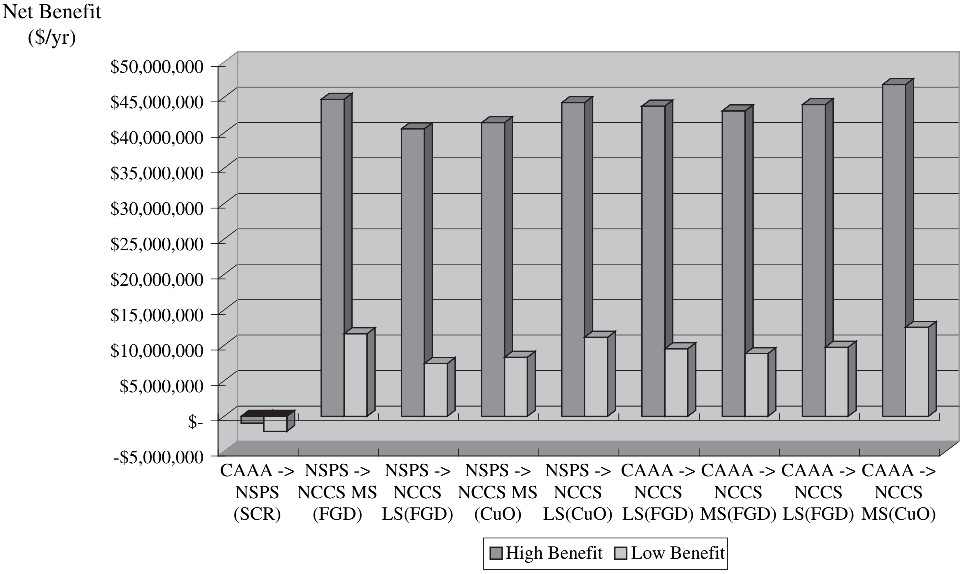
One additional consideration is how the technologies compare in their effects on other emissions, such as mercury, particulates, and carbon. In the Table 3 scenarios, solutions were required to meet the EPA PM standard of 0.03 lb/MBtu. The PM control used with conventional technologies is the ESP, while the lowest cost PM control for integrated technology is the pulse-jet FF. The two alternatives led to similar costs for PM control, ranging from about $1.10/mWh-net to $1.45/mWh-net. The amounts were generally higher for low-sulfur coal. However, this cost was included in the subtotal of emissions control costs, so that despite this secondary effect, low-sulfur coal with integrated technology was the most cost-effective solution. But a more complete analysis should consider secondary effects on mercury and possibly carbon. From an efficiency standpoint, all effects, not just direct effects, should be included.

IV. BENEFITS VERSUS COSTS OF TIGHTER STANDARDS FOR SO_2 AND NO_X

As new scientific evidence shows harm from ever smaller amounts of emissions, environmental legislation continues to reduce the amount of allowable emissions of SO_2 and NO_x. Society experiences benefits, primarily from reduced mortality and morbidity, as well as secondary benefits such as increased agricultural production and greater visibility.

10. For example, Duke Energy has eight coal-fired electric plants. They have installed an SCR on one unit of their Cliffside plant and they expect to complete shortly the installation of two SCRs on both units of Belews Creek. Another technology is known as selective noncatalytic reduction (SNCR).

FIGURE 1
Benefits versus Costs for SO_2 and NO_x Emissions Standards



While federal standards proposed by the EPA are not required to meet a benefit/cost test, it is desirable to compare benefits to costs. For states that propose standards more stringent than the federal standard, as in the case of the NCCSA, it is certainly appropriate to consider the benefits and costs of a more stringent standard.

Consider the three sets of standards: 1990 CAAA, 1997 NSPS, and the NCCSA. We consider the annual benefits and costs of moving from the CAAA to NSPS to NCCSA, as well as NSPS to NCCSA. According to Banzhaf et al. (2002), a reasonable range for benefits from reducing SO_2 is between \$1700/ton to \$4700/ton. For NO_x, the value is between \$700/ton and \$1200/ton.[11]

11. The ranges are from a 90% confidence interval Monte Carlo simulation to reflect uncertainty. The extreme values also encompass a sensitivity analysis that allows for differing values for the concentration response function for mortality effects and for the statistical value of human life. For example, the Monte Carlo simulation uses \$2.25 million for the value of a statistical life, which yields a most likely estimate of \$3500/ton for the marginal benefit of reducing SO_2 and \$1100/ton for NO_x. If the value-of-life estimate is \$6.1 million, the marginal benefit of reducing SO_2 and NO_x more than doubles, and the efficient caps for the two emissions are closer to the 90% end of the initial Monte Carlo estimates. All values are in 1999 dollars, consistent with costs.

Figure 1 shows annual net benefits among the three standards for the two coal types and for the high and low benefit estimates, based on the plant considered in the earlier tables. Appendix A contains three tables, each determining net benefits from more stringent standards. Table A1 is a comparison of CAAA to NSPS, Table A2 compares NSPS to NCCSA, and Table A3 compares CAAA to NSCS. The tables include calculations based on the change in total cost, and alternatively, the change in the emissions cost. The use of emissions cost affects the magnitude, but not the sign, of the net benefits measure.

The IECM calculates the annual change in emissions, measured in tons, for the two pollutants. Total benefit adds the benefit from sulfur and NO_x emissions. The separate benefits are the dollar per ton benefit, multiplied by the change in tons. The cost is the addition to cost from the more stringent standard, using the revenue requirement from the previous tables. Note that reductions in sulfur and NO_x emissions are a joint good, so that with multiple emissions, costs cannot be separated.

For both the high and low benefit cases, there is a negative net benefit when firms that meet CAAA are required to meet the NSPS.

The lowest cost method to meet the more stringent standard is to add an SCR. The annualized cost of the SCR, even allowing for the use of lower cost medium-sulfur coal, outweighs the benefit of lower sulfur and NO_x.

The usual convexity assumptions would predict that if the more stringent NSPS falls short on benefit/cost grounds, then even more stringent controls will be inefficient. In contrast, Figure 1 shows benefits exceed costs for moving from CAAA or NSPS to NCCSA. The net benefits are larger when the firm adapts from CAAA to NCCSA. Net benefits are in excess of $45 million for the high benefit case and in excess of $10 million for the low benefit case.

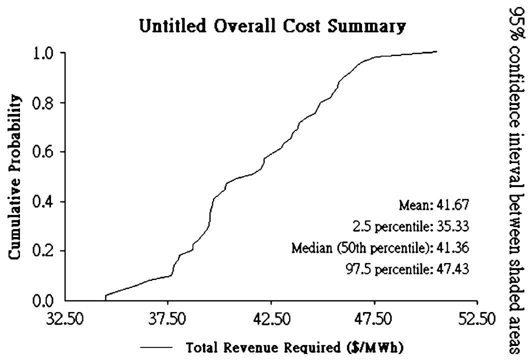
The primary explanation is the nonconvexity of marginal cost. The incremental cost of moving to the most stringent standard, as compared to the intermediate standard, is relatively small. Another factor is that marginal benefit is being held constant. If marginal benefit decreased with the more stringent standard, the net benefit to NCCSA would decrease. As the emphasis in this article is on determining costs, it is left to future research to reconsider benefits when there is a more detailed estimation of marginal benefits.[12]

V. UNCERTAINTY CONSIDERATIONS

Given the initial assumptions of the simulation, the lowest cost method for achieving the NCCSA standards is to adopt a CuO process along with low-sulfur coal. Embedded in the simulation is a set of default assumptions, including some parameters specified with probability distributions. Figure 2 shows a probabilistic distribution of costs for CuO with low-sulfur coal. Appendix B summarizes uncertainty parameter settings.

The lowest cost alternative was combining SCR and FGD. The expected cost of this technology is $45.12, considerably above the mean for CuO of $41.67. However, there is some overlap of the probability distributions, so

FIGURE 2
Probabilistic Costs for the CuO Technology Using Low-Sulfur Coal



that the cost of CuO could exceed that of SCR plus FGD.[13]

Finally, there is a sensitivity analysis that allows the financial assumptions regarding interest rates to increase or decrease. Table 4 shows a cost comparison for the original default case, as well as higher and lower costs of capital.

Copper oxide with low-sulfur coal remains the lowest cost option for all cases. Low interest rates do reduce the cost savings from CuO compared to SCR plus FGD. Were interest rates to continue to decline, it would be appropriate to make sure that CuO still has a cost advantage.

VI. CONCLUSION

There has been increasing attention paid to multiple pollutants in environmental legislation. The motivation for the multipollutant approach is to reduce the cost to electric utilities of meeting emissions constraints. The "piecemeal" approach, whereby regulations do not consider the interactions among emissions, results in the possibility that firms will choose technologies that result in excessive costs when regulations are later tightened. With the availability of integrated technologies that can reduce more than one pollutant at a time, a potential benefit of multipollutant

12. However, Banzhaf et al. (2002) find marginal benefit on the national level to be relatively constant, so the assumption in this article appears reasonable. That article also notes the importance of nonconvexity on the benefit side.

13. A future version of the IECM will have the ability to compare two probability distributions, so as to provide a distribution for the cost difference. It would then be possible to conclude, for example, that there is a 15% probability that CuO is more costly than the alternative and an 85% probability that CuO is the lowest cost alternative.

TABLE 4
Sensitivity of Technology Costs to Capital Cost Assumptions

Coal Type (LS, MS) + Technology (FGD, SCR, CuO, NO_xSO)		Revenue Requirement ($/mWh)	Emission Cost ($/mWh)
MS + SCR + FGD	Base	$45.26	$9.72
	Increase	$46.63	$8.93
	Decrease	$39.89	$8.84
LS + SCR + FGD	Base	$46.41	$8.88
	Increase	$45.49	$9.77
	Decrease	$41.08	$7.76
MS + CuO	Base	$43.34	$8.61
	Increase	$43.53	$8.63
	Decrease	$38.86	$8.18
LS + CuO	Base	**$42.75**	**$7.10**
	Increase	**$42.94**	**$6.05**
	Decrease	**$38.25**	**$5.62**
MS + NO_xSO	Base	$47.70	$12.29
	Increase	$47.93	$12.34
	Decrease	$42.27	$11.03
LS + NO_xSO	Base	$48.11	$10.48
	Increase	$48.55	$10.67
	Decrease	$42.95	$9.49

[a]The default assumptions for return on debt, common, and preferred stock are 4.6%, 5.2%, 8.7%.
[b]Assumptions for the "increase" case are 5.52%, 6.24%, 10.44% (a 20% increase in rates).
[c]Assumptions for the "decrease" case are 3.68%, 4.16%, 6.96% (a 20% decrease in rates).
The lowest cost case is in **bold**.

legislation is to encourage R&D as well as adoption of integrated technology when it minimizes costs.

In the scenarios considered in this article, the lowest cost technology to meet the 1990 CAAA required basic technologies, but not the use of scrubbers or catalytic converters to meet SO_2 or NO_x standards. Firms with plants subject to the 1997 NSPS had to consider catalytic devices such as SCRs in order to meet tougher NO_x restrictions. Although NSPS tightened sulfur restrictions as well, it was still possible to minimize the cost of meeting NSPS without a scrubber (FGD).

The coal-fired facilities of North Carolina electric utilities will be subject to still more stringent controls on sulfur and NO_x emissions than those in NSPS. These firms will not be able to meet the new standards with NO_x control alone. They must either add more technology such as a scrubber (FGD) to reduce sulfur further, or use integrated technology such as the CuO process.

According to the simulation, firms that were formerly subject to the 1990 CAAA standards would find it most cost effective to install the integrated CuO process under development at the DOE. In that case, the firms choose the lowest cost technology. But firms that were subject to the 1997 NSPS that had already installed a catalytic device (SCR) will find it less costly to add a scrubber (FGD) rather than to scrap the catalytic device and replace it with an integrated technology, even though the cost to a new firm would be lower with integrated technology.

Requiring firms that meet the 1990 CAAA to meet the more stringent 1997 NSPS has costs in excess of benefits. The usual convexity assumptions lead to the expectation that costs will exceed benefits for the still more stringent standards of the NCCSA legislation. However, that legislation has positive net benefits, whether the producer is moving from the CAAA or the NSPS. The IECM model that simulates engineering production costs allows for nonconvexity of costs; the increase in costs from NSPS to NCCSA is relatively small as compared to the increase in benefits, as the firm takes advantage of integrated technology to meet the most stringent standard. Results are robust with respect to simulations that allow for uncertainty in parameters, as well as a sensitivity analysis that considers an increase or a decrease in financing costs. In order for firms to choose the technology that is most cost effective, emissions standards should be chosen that recognize the relationship between emissions and the choices of technology. Today's regulations must consider the impact on future compliance costs, given the historic trend toward ever more stringent standards.

APPENDIX A: NET BENEFITS FROM MORE STRINGENT SO_2 AND NOX CONTROLS

TABLE A1

Annual Benefit and Cost Analysis (CAAA to NSPS)

Constraint	**CAAA**	**NSPS**
SO2 (lb/Mbtu)	2.5	1.2
NOX (lb/Mbtu)	0.45	0.15
Pollutant Control	Base case	NOx Control (SCR)
Coal	L/S	L/S
Δ Benefit	**CAAA (Total Benefits)**	**NSPS (Benefit Change)**
High Benefit		
SO2 ($4,700/ton)	$64,290,078	$432,306
NOX ($1,200/ton)	$3,851,334	$2,107,393
subtotal	$68,141,412	$2,539,699
Low Benefit		
SO2 ($1,800/ton)	$24,621,732	$165,564
NOX ($700/ton)	$2,246,612	$1,229,313
subtotal	$26,868,344	$1,394,877
ΔCosts	**CAAA (Total Cost)**	**NSPS (Cost Change)**
Revenue Requirement ($/yr)	$117,700,000	$3,500,000
Emission cost ($/yr)	$5,829,000	$4,077,000
Revenue Requirement ($/MWh)	$38.21	$1.53
Emission cost ($/MWh)	$1.89	$1.34
Δ(Benefit - Cost)	**CAAA**	**NSPS**
High Benefit	base case	$(960,300.80)
Low Benefit	base case	$(2,105,123.30)

TABLE A2

Annual Benefit and Cost Analysis (NSPS to NCCSA)

Regulation	**NSPS**	**NCCSA**	**NCCSA**	**NCCSA**	**NCCSA**
Technology	NO_x control (SCR)	SCR + FGD	SCR + FGD	CuO	CuO
Coal	LS	MS	LS	MS	LS
SO_2 (lb/MBtu)	1.2	0.16	0.16	0.16	0.16
NO_x (lb/MBtu)	0.15	0.07	0.07	0.07	0.07
ΔBenefit	**NSPS (Total B)**	**NCCSA (ΔB)**	**NCCSA (ΔB)**	**NCCSA (ΔB)**	**NCCSA (ΔB)**
High Benefit					
SO_2 ($4,700/ton)	$63,857,772	$53,025,419	$53,056,298	$53,028,507	$53,062,474
NO_x ($1,200/ton)	$1,743,941	$927,947	$930,312	$927,947	$930,312

continued

TABLE A2 continued

ΔBenefit	NSPS (Total B)	NCCSA (ΔB)	NCCSA (ΔB)	NCCSA (ΔB)	NCCSA (ΔB)
Subtotal	\$65,601,713	\$53,953,366	\$53,986,610	\$53,956,454	\$53,992,786
Low Benefit					
SO_2 (\$1,800/ton)	\$24,456,168	\$20,307,607	\$20,319,433	\$20,308,790	\$20,321,798
NO_x (\$700/ton)	\$1,017,299	\$541,302	\$542,682	\$541,302	\$542,682
Subtotal	\$25,473,467	\$20,848,910	\$20,862,115	\$20,850,092	\$20,864,480
ΔCosts	**NSPS (Total Cost)**	**NCCSA (ΔC)**	**NCCSA (ΔC)**	**NCCSA (ΔC)**	**NCCSA (ΔC)**
Rev Req (\$/yr)	\$121,200,000	\$9,200,000	\$13,400,000	\$12,500,000	\$9,700,000
Emission Cost (\$/yr)	\$9,906,000	\$19,004,000	\$16,624,000	\$16,704,000	\$8,594,000
Rev Req (\$/MWh)	\$40	\$6	\$7	\$4	\$3
Emission Cost (\$/MWh)	\$3	\$6	\$6	\$5	\$4
ΔBenefit vs. ΔCost	**NSPS**	**NCCSA**	**NCCSA**	**NCCSA**	**NCCSA**
High Benefit	Baseline	\$44,753,366	\$40,586,610	\$41,456,454	\$44,292,786
Low Benefit	Baseline	\$11,648,910	\$7,462,115	\$8,350,092	\$11,164,480

TABLE A3
Annual Benefit and Cost Analysis (CAAA to NCCSA)

Regulation	CAAA	NCCSA	NCCSA	NCCSA	NCCSA
SO_2(lb/MBtu)	2.5	0.16	0.16	0.16	0.16
NO_x (lb/MBtu)	0.45	0.07	0.07	0.07	0.07
Pollutant Control (ton/yr)	Base Case	SCR + FGD	SCR + FGD	CuO	CuO
Coal	L/S	M/S	L/S	M/S	L/S
Benefits Change	**CAAA (Total B)**	**NCCSA (Change)**	**NCCSA (Change)**	**NCCSA (Change)**	**NCCSA (Change)**
High Benefit					
SO_2 (\$4700/ton)	\$64,290,078	\$53,457,725	\$53,488,604	\$53,460,813	\$53,494,780
NO_x (\$1200/ton)	\$3,851,334	\$3,035,340	\$3,037,705	\$3,035,340	\$3,037,705
Subtotal	\$68,141,412	\$56,493,065	\$56,526,309	\$56,496,153	\$56,532,485
Low Benefit					
SO_2 (\$1800/ton)	\$24,621,732	\$20,473,171	\$20,484,997	\$20,474,354	\$20,487,362
NO_x (\$700/ton)	\$2,246,612	\$1,770,615	\$1,771,995	\$1,770,615	\$1,771,995
Subtotal	\$26,868,344	\$22,243,786	\$22,256,992	\$22,244,969	\$22,259,357
Cost Change	**CAAA (Total C)**	**NCCSA (Change)**	**NCCSA (Change)**	**NCCSA (Change)**	**NCCSA (Change)**
Rev Req (\$/yr)	\$117,700,000	\$12,700,000	\$13,400,000	\$12,500,000	\$9,700,000
Emission Cost (\$/yr)	\$5,829,000	\$23,081,000	\$16,624,000	\$16,704,000	\$8,594,000
Rev Req (\$/MWh)	\$38	\$7	\$7	\$4	\$3
Emission Cost (\$/MWh)	\$2	\$8	\$6	\$5	\$4
(Benefits − Costs) Change	**CAAA**	**NCCSA**	**NCCSA**	**NCCSA**	**NCCSA**
High Benefit	Base case	\$43,793,065	\$43,126,309	\$43,996,153	\$46,832,485
Low Benefit	Base Case	\$9,543,786	\$8,856,992	\$9,744,969	\$12,559,357

TABLE B1
Default Uncertainty Assumptions in the IECM Model

Control	Technology	Parameters	Nominal Value	Unit	Prob Dist	Normalized Values	Note
Common	Base Plant/Perf	Gross Cycle Heat Rate	7880	Btu/kWh	−1/2 N	(1.0, 0.018)	N-Normal
	Base Plant/Perf	Capacity Factor	75	%	N	(1.0, 0.07)	½ N-Half Normal
	Base Plant/Perf	Excess Air to Boiler	20	%	N	(1.0, 0.025)	−1/2 N-Neg.Half Normal
	Base Plant/Perf	Leakage Across Air Preheater	19	%	N	(1.0, 0.025)	U-Uniform
	Base Plant/Finn	Fixed Charge Factor (FCF)	0.1034	Fraction	U	(0.7, 1.3)	T-Triangular
	Base Plant/Finn	Real Return on Debt	4.60	%	N	(1.0, 0.1)	
	Base Plant/Finn	Real Return on Common Stock	8.70	%	N	(1.0, 0.1)	
	Base Plant/Finn	Real Return on Preferred Stock	5.20	%	N	(1.0, 0.1)	
	Mercury Control	Furnace Removal	7.00	%	T	(0, 1.0, 1.429)	
	PM control/Perf	Specific Collection Area	384.00	acfm/ft2	N	(1.0, 0.05)	
	PM control/Perf	Energy Requirement (Penalty)	0.2185	%MWg	N	(1.0, 0.1)	
	PM control/Capital	General Facilities Capital	1.00	%PFC	N	(1.0, 0.1)	
	PM control/Capital	Engineering & Home Office Fees	5.00	%PFC	N	(1.0, 0.1)	
	PM control/Capital	Process Contingency Cost	20.00	%PFC	N	(1.0, 0.1)	
	PM control/Capital	Project Contingency Cost	0.00	%PFC	N	(1.0, 0.1)	
	PM control/O&M	Waste Disposal Cost	11.3	$/ton	T	(0.8x, 1.0x, 1.2x)	
Conventional	SO2 control/Addi.	Dibasic Acid Makeup	20	n of SO2 rem	N	(1.0, 0.08)	
(Wet FGD)	SO2 control/Perf	Molar Stoichiometry	1.03	mol Ca/S	T	(1.02, 1.03, 1.05)	
	SO2 control/Capital	General Facilities Capital	10	%PFC	L	(1.0, 0.013)	
	SO2 control/Capital	Engineering & Home Office Fees	10	%PFC	½ N	(1.0, 0.17)	
	SO2 control/Capital	Project Contingency Cost	15	%PFC	U	(0.67x, 1.33x)	
	SO2 control/Capital	Process Contingency Cost	2	%PFC	½ N	(1.0, 0.50)	
	SO2 control/O&M	Limestone Cost	16.21	$/ton	U	(0.7x, 1.3x)	
	SO2 control/O&M	Disposal Cost	8.809	$/ton	T	(0.61x, 1x, 1.84x)	
	SO2 control/O&M	Dibasic Acid Cost	389.1	$/ton	N	(1.0, 0.05)	
Conventional	NoX control/Perf	Min Activity	0.5		U	(1x, 1.5x)	
(SCR)	NoX control/Perf	Activity at Reference Time	0.85		N	(1.0, 0.03)	
	NoX control/Perf	Total Pressure Drop	9	in H2O gauge	N	(1.0, 0.05)	
	NoX control/Perf	Ammonia Slip	5	ppmv	T	(1x, 1.001x, 2x)	
	NoX control/Perf	Energy Requirement (Penalty)	0.5183	%MWg	N	(1.0, 0.05)	
	NoX control/Capital	General Facilities Capital	10	%PFC	N	(1.0, 0.1)	
	NoX control/Capital	Engineering & Home Office Fees	10	%PFC	T	(0.7x, 1x, 1.5x)	
	NoX control/Capital	Project Contingency Cost	10	%PFC	N	(1.0, 0.1)	
	NoX control/Capital	Process Contingency Cost	5.054	%PFC	N	(1.0, 0.1)	

	NoX control/Capital	Misc. Capital Costs	2	%TPI	N	(1.0, 0.1)
	NoX control/Capital	Inventory Capital	0.5	%TPC	N	(1.0, 0.1)
	NoX control/O&M	Ammonia Cost	204.9	$/ton	U	(1x, 1.5x)
	NoX control/O&M	Catalyst Cost	324.2	$/ton	T	(0.67x, 1x, 1.33x)
	NoX control/O&M	Total Maintenance Cost	2	%TPC	N	(1.0, 0.1)
	NoX control/O&M	Admin & Support Cost	30	%total labor	N	(1.0, 0.1)
Integrated	CuO control/Perf	Sorbent Stoichiometry	1.387	total Cu/mol	N	(1.0, 0.05)
Copper Oxide	CuO control/Perf	Ammonia Stoichiometry	0.7887	nol N/mol NO	N	(1.0, 0.0625)
	CuO control/Perf	Absorbers	2.00E-02	% of bed inven	T	(0.5x, 0.55x, 1x)
	CuO control/Perf	Circulation System	4.70E-02	% of circulati	T	(0.43x, 1x, 1x)
	CuO control/Absor.	Sprbent Fluidized Bed Density	26.6	lb/cu ft	T	(0.92x, 1x, 1.08x)
	CuO control/Rege.	CuSO3 Regeneration Efficiency	80	%	U	(0.5, 1.0)
	CuO control/Capital	General Facilities Capital	10	%PFC	N	(1.0, 0.1)
	CuO control/Capital	Engineering & Home Office Fees	15	%PFC	N	(1.0, 0.1)
	CuO control/Capital	Project Contingency Cost	20	%PFC	N	(1.0, 0.2)
	CuO control/Capital	Process Contingency Cost	14.10	%PFC	N	(1.0, 0.3)
	CuO control/Capital	Misc. Capital Costs	2	%TPI	N	(1.0, 0.1)
	CuO control/Capital	Inventory Capital	0.5	%TPC	N	(1.0, 0.1)
	CuO control/O&M	Sorbent Cost	5.38	$/lb	T	(0.5x, 1x, 1x)
	CuO control/O&M	Ammonia Cost	204.9	$/ton	U	(1x, 1.5x)
	CuO control/O&M	Natural Gas Cost	3.783	$/mscf	T	(0.5x, 1x, 1x)
	CuO control/O&M	Total Maintenance Cost	4.5	%TPC	N	(1.0, 0.1)

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