INTEGRATED ENVIRONMENTAL CONTROL CONCEPTS FOR COAL-FIRED POWER SYSTEMS

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Implications

Estimating the performance and cost of advanced technologies still under development is one of the most difficult tasks facing decision makers, policy analysts and research managers in the public and private sectors. The modeling framework described in this paper offers an approach to help minimize technological risks by explicitly considering uncertainties in the development of performance and cost estimates for integrated environmental control options applicable to modern coal-based power generation systems.

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ABSTRACT

The capability to estimate the performance and cost of advanced environmental control systems for coal-fired power plants is critical to a variety of planning and analysis requirements faced by utilities, regulators, researchers and analysts in the public and private sectors. This paper describes a computer model developed for the U.S. Department of Energy (USDOE) to provide an up-to-date capability for analyzing a variety of pre-combustion, combustion, and post-combustion options in an integrated framework. A unique feature of the model allows performance and costs of integrated environmental control concepts to be modeled probabilistically as a means of characterizing uncertainties and risks. Examples are presented of model applications comparing conventional and advanced emission control designs. The magnitude of technology risks associated with advanced technologies now under development are seen to vary markedly across applications. In general, however, integrated environmental control concepts show significant potential for more cost-effective methods of emissions control.

INTRODUCTION

Over the past two decades, new environmental control requirements have substantially altered the design of fossil fuel power plants, especially for coal-fired plants, which supply nearly 60 percent of U.S. electricity demand. For the most part, the response to environmental regulations has been a largely piecemeal approach, wherein new technologies have been added to address each new problem that arises. The result of this approach has been high cost and often unsatisfactory performance.

More recently, the concept of integrated environmental control has emerged as an important new paradigm for the design of electric power systems. This concept has a number of dimensions. One involves the integration of pollution control functions currently carried out in separate devices or unit operations, for example the replacement of separate processes for SO_2 and NO_x control by a single system for combined removal of both pollutants. Integration also includes the consideration of methods to control air pollutants, water pollutants and solid wastes simultaneously, as opposed to separate solutions for each environmental medium. Finally, the concept of integrated control includes an examination of environmental control options at different stages of the fuel cycle, for example, control methods that can be applied before, during and after the combustion process, as opposed to a focus on one area alone.

This paper describes a computerized modeling framework developed for the U.S. Department of Energy (USDOE) to provide the capability to analyze the performance and cost of integrated emission control concepts for coal-fired electric power plants. This capability is critical to a variety of planning, analysis, and design requirements faced by utility companies, regulators, researchers, and analysts. A unique capability of the model is that it allows performance and costs to be characterized probabilistically, using Monte Carlo methods to quantify performance and cost uncertainties and risks.

MODELING FRAMEWORK

The Integrated Environmental Control Model (IECM) allows systematic analysis of emission control options for coal-fired power plants employing a variety of pre-combustion, combustion and post-combustion control methods. The model was developed to provide preliminary performance and cost estimates for new baseload power plants as well as existing plants considering technology retrofits. Of particular interest are a number of advanced environmental control technologies being developed with support from USDOE. For comparative purposes, however, a set of "baseline" technologies representing current commercial systems also is part of the IECM framework.

Table 1 lists the technologies currently included in the model. For each technology, a process performance model accounts for all energy and mass flows (including air pollutants and solid wastes) associated with that process. Coupled to each performance model, an economic model estimates the capital cost, annual operating and maintenance (O&M) costs, and total levelized cost of each technology. The technology models developed for the IECM in the mid-tolate 1980s recently have been updated and enhanced to reflect current design criteria and associated performance and costs. The status of major IECM components is briefly reviewed below. Additional details are provided elsewhere.[1,2]

Coal Cleaning Processes

The IECM includes models of both conventional and advanced coal cleaning processes. The conventional processes include four plant designs of increasing complexity, which provide increasing capability for sulfur as well as ash removal.[3] Each of these plant designs (referred to as cleaning levels 2, 3, 4 and 5) can be optimized to achieve a target sulfur or ash reduction while maximizing overall yield (thus minimizing costs). Data requirements for these models includes coal-specific washability data plus cleaning circuit design parameters such as top size and bottom size for different coal fractions.

Models of several advanced physical coal cleaning processes also have been developed based on limited data for several U.S. coals.[1,2] While these processes are capable of achieving higher levels of sulfur and ash reduction than conventional processes, their costs also are higher. Several of these processes have been developed to provide “super-clean” coal for use in coal-liquid mixture fuels, which compete with other premium fuels such as oil or gas.

Base Power Plant

Performance and cost models of a base power plant are needed to accurately characterize the cost of integrated emission control systems, particularly when coal cleaning is employed. The IECM base plant performance model includes detailed mass and energy balances, fuel combustion equations, and thermodynamic relationships to calculate flue gas flow rates, plant efficiency, and net power generation. The environmental performance of the furnace also is determined from mass and energy balances where possible, or from empirical relationships where necessary, as in the case of NO_x emissions. A detailed model of the air preheater also has been developed[2] to properly account for energy credits for advanced environmental control processes.

Revised cost models for the base power plant have been developed based on recent data from the Electric Power Research Institute (EPRI) for furnace designs appropriate for different coal ranks (bituminous, subbituminous and lignites).[4] The new cost algorithms estimate capital costs and annual O&M costs as a function of key plant design and operating parameters.[5] A feature of all the IECM cost models is that each technology is disaggregated into a number of different process areas, typically four to eight areas per technology, depending on its complexity. The direct cost of each process area is calculated based on appropriate flowsheet parameters such as a mass or volume flow rate, species concentration, temperature, pressure, etc.. Additional indirect costs are estimated based on the total process facilities costs, following standard EPRI accounting methods.[4] In this way, the IECM captures important linkages between process design, performance and cost.

NO_X Controls

The IECM includes both in-furnace and post-combustion NO_X control options. Currently, the in-furnace combustion controls include low NO_X burners for a new power plant meeting or exceeding U.S. federal New Source Performance Standards. Additional combustion options suitable for NO_X retrofits currently are being developed.

Post-combustion control methods include both “hot-side” and “cold-side” selective catalytic reduction (SCR) systems. New SCR performance and cost models incorporate recent data and experience from SCR units worldwide. The revised models contain a larger number of system design parameters, a more detailed characterization of catalyst activity, and additional details related to capital cost and O&M cost parameters.[6] While SCR systems on coal-fired plants are only now emerging commercially in the United States, their widespread use in Europe and Japan represents the benchmark design for comparisons with advanced emissions control systems being developed by DOE.

Particulate Emission Controls

The IECM includes performance and cost models for cold-side electrostatic precipitators (ESP) and fabric filters. Cost models for both technologies recently have been updated to reflect current applications.[7,8] The revised ESP performance model calculates total flyash removal as a function of ash composition and flue gas properties, while fabric filter performance is related primarily to the air-to-cloth ratio. The latter models also have been expanded to include both reverse gas and pulse jet fabric filter designs. Recent EPRI design studies have been used to update the economic models for all particulate collectors.[7,8]

Flue Gas Desulfurization Systems

Substantial improvements in FGD system design, accompanied by reductions in cost, have been seen over the past decade, and recent enhancements to the IECM modules now reflect these changes.[9] New FGD performance and cost models have been developed for the IECM for four common types of FGD systems: (1) wet limestone with forced oxidation; (2) wet limestone with dibasic acid additive; (3) magnesium-enhanced wet lime system; and (4) a lime spray dryer system. The new cost models reflect the results of recent studies for EPRI, while the new performance models represent the capabilities of modern commercial systems.[10]

Combined SO_2/NO_x Removal Processes

A key element of USDOE's Clean Coal Technology program focuses on advanced processes for combined SO_2 and NO_x removal to achieve high environmental performance goals at lower cost than the conventional combination of SCR plus FGD. Models of three SO_2/NO_x control systems have been developed for the IECM: the fluidized-bed copper oxide process, the electron beam process and the NOXSO process. The copper oxide and NOXSO processes are of continuing interest to USDOE, and earlier versions of the performance and cost models for these two processes have been refined and updated based on recent proof-of-concept testing.[11,12]

Waste Disposal and By-Product Recovery Systems

The IECM treats solid waste disposal as a variable cost item associated with a particular control technology, consistent with the costing method used by EPRI and others. Thus, boiler bottom ash disposal is included in the base plant model, fly ash disposal costs are incorporated in the ESP or fabric filter models, and FGD wastes or by-product credits are treated in the FGD cost models.

Advanced processes employing combined SO_2/NO_x removal produce by-product sulfur or sulfuric acid rather than a solid waste. Because the sulfur or sulfuric acid plant is a significant part of the overall plant cost, separate engineering models have been developed for these two components.[2] These models are sensitive to input gas composition and other parameters affecting overall process economics.

PROBABILISTIC CAPABILITY

A unique feature of the IECM is its ability to characterize input parameters and output results probabilistically, in contrast to conventional deterministic (point estimate) models. This method of analysis offers a number of important advantages over the traditional approach of examining uncertainties only through sensitivity analysis. Probabilistic analysis allows the interactive effects of variations in many different parameters to be considered simultaneously, in contrast to sensitivity analysis where only one or two parameters at a time are varied, with all other parameters held constant. In addition, probabilistic analysis provides quantitative insights about the *likelihood* of various outcomes, and the probability that one result may be more significant than another. This type of information on technical and economic risks often is of greater value than simple bounding or “worst case” analyses obtained from sensitivity studies, which contain no information on the likelihood of worst case occurrences.

The ability to perform probabilistic analysis comes from the use of a software system which uses a non-procedural modeling environment designed to facilitate model building and probabilistic analysis.[13] In addition to a number of standard probability distributions (e.g., normal, lognormal, uniform, chance), the IECM can accommodate any arbitrarily specified distribution for input parameters. Given a specified set of input uncertainties, the resulting uncertainties induced in model outputs are calculated using median Latin Hypercube sampling, an efficient variant of Monte Carlo simulation. Results typically are displayed in the form of a cumulative probability distribution showing the likelihood of reaching or exceeding various levels of a particular parameter of interest (e.g., efficiency, emissions or cost).

MODEL APPLICATIONS

The IECM is intended to support a variety of applications related to technology assessment, process design, and research management. Examples of questions that can be addressed with the model include the following:

- What uncertainties most affect the overall costs of a particular technology?
- What are the key design trade-offs for a particular process?
- What are the potential payoffs and risks of advanced processes vis-a-vis conventional technology?
- Which technologies appear most promising for further process development?
- What conditions or markets favor the selection of one system design (or technology) over another?
- How can technical and/or economic uncertainties be reduced most effectively through further research and development?

The IECM recently has been modified to allow estimation of retrofit costs as well as new plant costs. A series of user-specified retrofit factors may be applied at the process area level for a particular system to estimate the higher costs of retrofit facilities. To use the model, a graphical interface has been developed which provides an extremely user-friendly mode of operation.[14]

Here we present results illustrating the capabilities of the IECM to evaluate and compare conventional and advanced emissions control system. The base case plant shown in Figure 1 achieves 90% SO_2 removal employing a wet limestone FGD system with forced oxidation, and 90% NO_x removal using low-NO_x burners plus a hot-side SCR system. A cold-side ESP is used for flyash collection to meet the federal New Source Performance Standard of 0.03 lbs/10^6 Btu. The base plant produces solid wastes (gypsum and ash) that are disposed of in a landfill.

The advanced process modeled in this illustration is the fluidized bed copper oxide process, being developed with support from USDOE. A brief overview of this process provides background for the comparative analysis that follows.

Copper Oxide Process Overview

The fluidized-bed copper oxide process is designed to achieve at least 90 percent removal of both SO_2 and NO_x from power plant flue gases in a single reactor vessel. The process is regenerative, producing a marketable sulfur or sulfuric acid byproduct in lieu of a solid waste containing spent sorbent. A simple schematic of a power plant with the copper oxide process is shown in Figure 2.

In a commercial-scale process, a bed of copper-impregnated sorbent, consisting of small diameter alumina spheres, is fluidized by the power plant flue gas. Removal of SO_2 and SO_3 in the flue gas occurs by reaction with copper oxide in the sorbent, while NO_x is removed by reaction with ammonia injected into the flue gas upstream of the absorber. The reaction is catalyzed by copper sulfate and promoted by mixing within the fluidized bed. The absorber reactions are exothermic, and this incremental thermal energy can be recovered in the power plant air preheater, resulting in an energy credit. The sulfated sorbent is transported from the fluidized bed absorber to a solids heater and then to a regenerator. Regeneration of the sorbent occurs by reaction with methane, converting the copper sulfate and unreacted copper oxide to elemental copper. An off-gas containing sulfur dioxide is further processed to recover elemental sulfur in a modified Claus plant. The regenerated sorbent is then transported back to the absorber.

The copper oxide process performance model includes the fluidized bed absorber, sorbent heater, regenerator, solids transport system, and ammonia injection system. The IECM also characterizes the performance of an integrated sulfur recovery plant and the power plant air preheater. In previous studies, the performance and cost of the fluidized bed copper oxide process were analyzed extensively, and compared to a conventional plant meeting the same emission standards with FGD and SCR.[15] Previous studies also examined the potential of targeted research and development to lower costs and improve process competitiveness.[16] Earlier studies, however, were based on models of conventional FGD and SCR systems reflecting experience and designs of the early 1980s, and on limited bench-scale data for the copper oxide process performance. The earlier copper oxide data now have been supplemented by more recent data from a life cycle test unit (LCTU), additional bench-scale data on regeneration, and a detailed conceptual design of a commercial-scale plant.[11]

In this paper we employ the newly revised performance and cost models of both the "conventional" emission control systems and the fluidized bed copper oxide process. Integrated systems employing physical coal cleaning in addition to post-combustion controls also are considered. Table 2 shows the properties of two coals used for the analysis. A gross power plant size of 522 MW with an annual capacity factor of 65 percent is assumed. In-plant energy requirements are calculated by the model. Assumptions regarding the uncertainties in model parameters are shown in Table 3 for the base plant environmental control system and Table 4 for the advanced emission control system using copper oxide. Table 5 shows additional uncertainties common to both designs, including base power plant operating parameters, and financial parameters that determine the fixed charge factor used to amortize capital costs. All costs are reported in constant 1993 dollars and normalized on net plant output.

Case Study Results

Figure 3 shows the total capital cost of emission control systems for SO_2, NO_x and particulates for the two power plant designs, based on 100 iterations of the model. For the case of the Pittsburgh No. 8 coal, the copper oxide system cost is generally lower, but shows greater uncertainty than the base plant with SCR/FGD. For the higher sulfur Illinois coal, however, the base plant costs are generally lower than the copper oxide plant. Figure 4 shows a similar comparison for the total levelized cost of emissions control. For the two coals modeled, these costs range from about 8 to 15 mills/kWh for the base plant, and 7 to 17 mills/kWh for the advanced plant. In both cases, the high end of the range corresponds to the high sulfur coal plants, whose average cost is 2.5 to 3.8 mills/kWh higher than for the medium sulfur plants. Both the mean and variance of the costs for each plant configuration increase with increasing sulfur content. Table 6 summarizes the mean values of cost results for the two plants, along with the 90 percent confidence interval from the stochastic simulations.

Because of the considerable overlap in cost for the two processes, a more insightful comparison comes from examining the *difference* in costs between the two processes. A probabilistic representation of cost differences can be obtained by a numerical procedure that insures that parameters common to the two systems (such as the fixed charge factor, reagent costs, labor costs, etc.) have identical values when those parameters are sampled in the stochastic simulation.

The results of such an analysis are displayed in Figure 5, which shows the levelized cost *savings* of the copper oxide system over the base plant design for the two coals. A negative value on this graph thus indicates that the advanced plant design is actually *more* costly than the base plant design. Indeed, for the high sulfur Illinois No. 6 coal, the likelihood of the copper oxide system producing a net cost savings is only about 20 percent. For the medium sulfur Pittsburgh coal, however, there is a much higher probability — around 70 percent — that the advanced system design will be less costly than the conventional plant with SCR and FGD. Thus, the copper oxide system is most attractive for medium and lower sulfur coal applications. This is largely because of the strong link between sorbent flow rate and the size of process equipment: process sorbent requirements increase rapidly with increasing coal sulfur content, adding considerably to both capital and operating costs.

Other variations of these plant configurations also were modeled to determine their cost implications. One integrated plant design explored the use of physical coal cleaning to reduce the sulfur and ash content of coal prior combustion, thus reducing the capital and operating costs of environmental control equipment at the power plant. Previous studies[15] had shown that reducing the coal sulfur content by approximately 30 percent using a modern (Level 4) cleaning plant could lower the expected cost of the base plant design for the high-sulfur Illinois coal. However, with the updated cost and performance models described in this paper, the small cost advantage found in the previous study was no longer realized. This is primarily because the lower cost of modern FGD systems yielded much smaller post-combustion control equipment cost savings which were insufficient to offset the cost of coal cleaning. Cost results for integrated system designs employing pre-combustion cleanup of coal, however, tend to be highly site-specific, so that the results of these particular case studies cannot be generalized to other situations.

Additional studies were performed to explore other process integration issues and cost advantages that may not be apparent when environmental control technologies are examined individually. One such advantage for the conventional power plant design is the gas conditioning effect from the use of an SCR system upstream of an electrostatic precipitator. The SCR performance model converts some of the sulfur dioxide in the flue gas stream to SO_3 which, in turn, affects the performance of the cold-side ESP, reducing the plate collector area needed to achieve a given flyash removal efficiency. The presence of an SCR system thus reduces the capital cost of the ESP, in this case by approximately $5/kW.

For the copper oxide system, a key integration issue involves tradeoffs regarding the air preheater and downstream particulate collector. In order to fully recover the energy released in exothermic chemical reactions associated with sulfur removal, a larger (more expensive) air preheater is required. If the preheater is not re-sized, the higher flue gas temperature generated by the copper oxide system increases the capital cost of downstream particulate equipment, whose cost depends on the actual volumetric gas flow rate. Thus, an integrated analysis is required to determine the least-cost solution for a particular application.

Another integration issue for the advanced plant design is the choice of particulate collector downstream of the SO_2/NO_x removal system. In the examples above, a conventional reverse gas fabric filter was assumed. In this application, a fabric filter is preferable to an ESP because of the low sulfur content of the flue gas. However, advanced fabric filter technology employing a pulse jet system instead of current reverse gas cleaning offers the potential to reduce the capital cost of the advanced plant design by at least $25/kW, according to the results of additional analysis. On a levelized cost basis, this improves the likelihood of the copper oxide plant design being less costly than the conventional system. For example, for the Pittsburgh No. 8 coal the probability of a cost savings increases to approximately 90 percent with a pulse jet fabric filter, as compared to 70 percent with the conventional reverse gas system (Figure 6). The absolute value of expected cost savings also increases as the cumulative probability distributions in Figure 5 shift toward the right.

DISCUSSION

The results presented here can be a starting point for further analyses to explore the primary sources of uncertainty, and the potential for R&D to improve performance and lower costs by reducing the uncertainties that matter most. Other recent papers[9,16] illustrate how results from the IECM can be used in conjunction with statistical and decision analysis methods to explore such issues. For example, partial rank correlation coefficients (PRCC) can be used to identify the key process variables and uncertainties that most affect system cost. Research efforts can then concentrate on those areas that offer the greatest potential payoff for process improvements. Decision analysis methods can be used to quantify the expected benefits of a targeted program of process development.

Improvements in conventional technologies such as FGD and SCR also put downward pressure on the level of allowable emissions. For example, SO_2 removal efficiencies of 95% to 98% or more are now available with commercial guarantees, as compared to no more than 90% less than a decade ago. Regulatory requirements reflecting best available technology thus can be expected to grow more stringent over time, imposing new requirements for advanced technology

In the case of the copper oxide process, for instance, the performance limits of the fluidized bed design modeled in this paper may be inadequate to economically achieve combined SO_2/NO_x removal efficiencies of 95% or more, as may be required by the end of this decade. Thus, the USDOE is currently pursuing a new design involving a moving bed reactor to achieve higher efficiencies. Future enhancements to the IECM will incorporate the results of this on-going research to reflect updated assessments of process, performance and cost in a stochastic framework.

CONCLUSION

This paper has described an integrated modeling framework for evaluating the cost and performance of conventional and advanced power plant emission control systems. The IECM framework also facilitates comparisons between alternative systems, particularly advanced technologies that may offer improved performance and/or cost characteristics. In such cases, the probabilistic capability of the models described here can be especially helpful in quantifying the risks as well as potential payoffs of advanced technologies, investment strategies, and R&D priorities.

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Table 1. Emissions control technology options for the IECM

Plant Area	**Baseline Processes**	**Advanced Processes**
Physical Coal Cleaning	• Level 2 Plant • Level 3 Plant • Level 4 Plant • Froth Flotation	• Selective Heavy Liquid Cyclones • Coal-Pyrite Flotation • Magnetic Separation
Combustion Controls	• Low NO_x Burners	• Reburning (gas)[a] • Slagging Combustors[a]
Post-Combustion Controls	• Selective Catalytic Reduction (Hot-side and Cold-Side) • Wet Limestone FGD • Wet Limestone with Additives • Wet Lime FGD • Lime Spray Dryer • Electrostatic Precipitator (Cold-side) • Reverse Gas Fabric Filter • Pulse Jet Fabric Filter	• NOXSO • Copper Oxide • Electron Beam • Advanced SO_2/NO_x Removal[a]
Waste Disposal & By-Product Recovery	• Landfill • Ponding	• Sulfur Recovery • Sulfuric Acid Recovery • Gypsum

[a] Planned for future model versions.

Table 2. Coal properties for case studies

Property	Illinois #6 Coal	Pittsburgh #8 Coal
Heating Value, Btu/lb	10,190	13,400
Sulfur, wt%	4.36	2.15
Carbon, wt%	57.0	74.8
Hydrogen, wt%	3.7	4.6
Oxygen, wt%	7.2	5.3
Nitrogen, wt%	1.1	1.4
Moisture, wt%	12.3	2.7
Ash, wt%	14.34	9.05
Coal Cost (at mine), $/ton	26.10	33.40
Transport Cost, $/ton	7.90	7.90
Delivered Cost, $/ton	34.00	41.30

Table 3. Uncertainties for baseline system environmental control design

Model Parameter	Deterministic (Nominal) Value[a]	Prob Dist[b]	Values (or σ as % of mean)[c]
Selective Catalytic Reduction			
Minimum Activity	0.5	U	(1x - 1.5x)
Relative Activity	0.90	N	(2.9%)
Activity at Reference Time	0.85	N	(3%)
Total Pressure Drop	9 in H2O g	N	(5%)
Ammonia Slip	5 ppmv	T	(1x, 1.001x, 2x)
Energy Requirement	(calc)% MWg	N	(5%)
Process Facility Capital	(calc) M$	N	(10%)
General Facilities Capital	10% PFC	N	(10%)
Eng. & Home Office Fees	10% PFC	T	(0.7x, 1x, 1.5x)
Project Contingency Cost	10% PFC	N	(20%)
Process Contingency Cost	(calc)% PFC	N	(30%)
Misc. Capital Costs	2% TPI	N	(10%)
Inventory Capital	0.5% TPC	N	(10%)
Ammonia Cost	150 $/ton	U	(1x - 1.5x)
Catalyst Cost	300 $/ton	T	(0.67x, 1x, 1.33x)
Total Maintenance Cost	2% TPC	N	(10%)
Admin. & Support Cost	(calc)% PFC	N	(10%)
Cold-Side Electrostatic Precipitator			
Specific Collection Area	(calc) acfm/ft2	N	(5%)
Energy Requirement	(calc)% MWg	N	(10%)
Process Facility Capital	(calc) M$	N	(10%)
General Facility Capital	1% PFC	N	(10%)
Eng. & Home Office Fees	5% PFC	N	(10%)
Project Contingency Cost	20% PFC	N	(10%)
Process Contingency Cost	(calc)% PFC	N	(10%)
Disposal Cost	10.24$/ton	T	(0.8x, 1x, 1.2x)
Total O&M Costs	(calc) M$/yr	N	(10%)
Wet FGD System			
No. Operating Trains	2 @50% ea.		
No. Spare Trains	0		
Molar Stoichiometry	.103 mol Ca/S	T	(1.02, 1.03, 1.05)
Energy Requirement	(calc) % MWg	N	(calc)
Reagent Feed System	(calc) M$	N	(calc)
SO_2 Removal System	(calc) M$	N	(calc)
Flue Gas System	(calc) M$	N	(calc)
Solids Handling System	(calc) M$	N	(calc)
General Support Area	(calc) M$	N	(calc)
Miscellaneous Equipment	(calc) M$	N	(calc)
Process Facility Capital	(calc) M$	N	(10%)
General Facilities Capital	10% PFC	L	(1.3 %)
Eng. & Home Office Fees	10% PFC	1/2 N	(17%)
Project Contingency Cost	15% PFC	U	(0.67x - 1.33x)
Process Contingency Cost	2% PFC	1/2 N	(50%)
Limestone Cost	15 $/ton	U	(0.7x - 1.3x)
Disposal Cost	8.15 $/ton	T	(0.61, 1, 1.84)
Total O&M Costs	(calc) M$/yr	N	(10%)

a Values labeled “calc” are calculated within the model
b L = Lognormal, N = Normal, U = Uniform
c x denotes the deterministic value.

Table 4. Uncertainties for advanced system environmental control design

Model Parameter	Deterministic (Nominal) Value[a]	Prob Dist[b]	Values (or σ as % of mean)[c]
Copper Oxide Process			
No. Operating Trains	2 @50% ea.		
No. Spare Trains	0		
Regenerator Residence Time	(calc) min	N	(10%)
Ratio of Avail. Cu to SOx	(calc) mol CuO/SOx	N	(5%)
Ammonia Stoichiometry	(calc) mol NH3/NOx	N	(6.25%)
Sorbent Attrition			
Circ. System	0.047 wt-% Circ.	T	(0.43x, 1x, 1x)
Fluidized Bed	0.02 wt-% Bed Inv.	T	(0.5x, 0.55x, 1x)
Sorbent Fluid. Bed Density	26.6 lb/cu ft	T	(0.92x, 1x, 1.08x)
Installation Cost Factor	45%	N	(10%)
Process Facility Capital	(calc) M$	N	(10%)
General Facilities Capital	10% PFC	N	(10%)
Eng. & Home Office Fees	15% PFC	N	(10%)
Project Contingency Cost	20% PFC	N	(20%)
Process Contingency Cost	(calc)% PFC	N	(30%)
Misc. Capital Costs	2% TPI	N	(10%)
Inventory Capital	0.5% TPC	N	(10%)
Sorbent Cost	5.00 $/lb	T	(.0.5x, 1x, 1x)
Natural Gas Cost	3.50 $/mscf	T	(0.7x, 1x, 1.3x)
Ammonia Cost	150 $/ton	U	(1x - 1.5x)
Sulfur Credit	(calc) $/ton	T	(0.5x, 1x, 1x)
Sulfuric Acid	53 $/ton	-1/2 N	(10%)
Maintenance Cost	4.5 % TPC	N	(10%)
Total O&M Cost	(calc) M$/yr	N	(10%)
Fabric Filter			
Gross Air to Cloth Ratio	2.0 acfm/sq ft	N	(5%)
Bag Life	4 yrs	N	(30%)
Process Facility Capital	(calc) M$	N	(10%)
General Facility Capital	1% PFC	N	(10%)
Eng. & Home Office Fees	5% PFC	N	(10%)
Project Contingency Cost	20% PFC	N	(10%)
Process Contingency Cost	(calc)% PFC	N	(10%)
Fabric Filter Bag Cost	80 $/bag	N	(5%)
Disposal Cost	10.24 $/ton	T	(0.8x, 1x, 1.2x)
Total O&M Cost	(calc) M$/yr	N	(10%)

a Values labeled “calc” are calculated within the model
b L = Lognormal, N = Normal, U = Uniform
c x denotes the deterministic value.

Table 5. Uncertainties for base power plant system

Model Parameter	Deterministic (Nominal) Value	Probability Distribution	Values (or σ as % of mean)
Power Plant			
Gross Cycle Heat Rate	9500 Btu/kWh	-1/2 Normal	(1.8%)
Capacity Factor	65%	Normal	(7%)
Excess Air to Boiler	20%	Normal	(2.5%)
Leakage Across Air Preheater	19%	Normal	(2.5%)
Financial Parameters			
Real Return on Debt	4.6%	Normal	(10%)
Real Return on Common Stock	8.7%	Normal	(10%)
Real Return on Preferred Stock	5.2%	Normal	(10%)
Real Escalation Rate	0%	1/2 Normal	(0.06%)

Table 6. Summary of case study cost results
(Mean values and 90% CI of emission control costs constant $1993)[a]

Case	Illinois #6 Coal		Pittsburgh #8 Coal	
	$/kW	**mills/kWh**	**$/kW**	**mills/kWh**
Base Plant (SCR/ESP/FGD)	233 (207-258)	12.0 (10.3-13.7)	207 (184-230)	9.5 (8.2-10.8)
Advanced Plant (CuO/FF)	262 (227-298)	13.0 (11.1-15.1)	192 (169-217)	9.2 (8.1-10.5)
Advanced Plant w/Pulse Jet FF	237 (201-270)	12.3 (10.5-14.3)	167 (143-191)	8.6 (7.5-10.0)

[a] Range in parenthesis is the 90 percent confidence interval (CI).

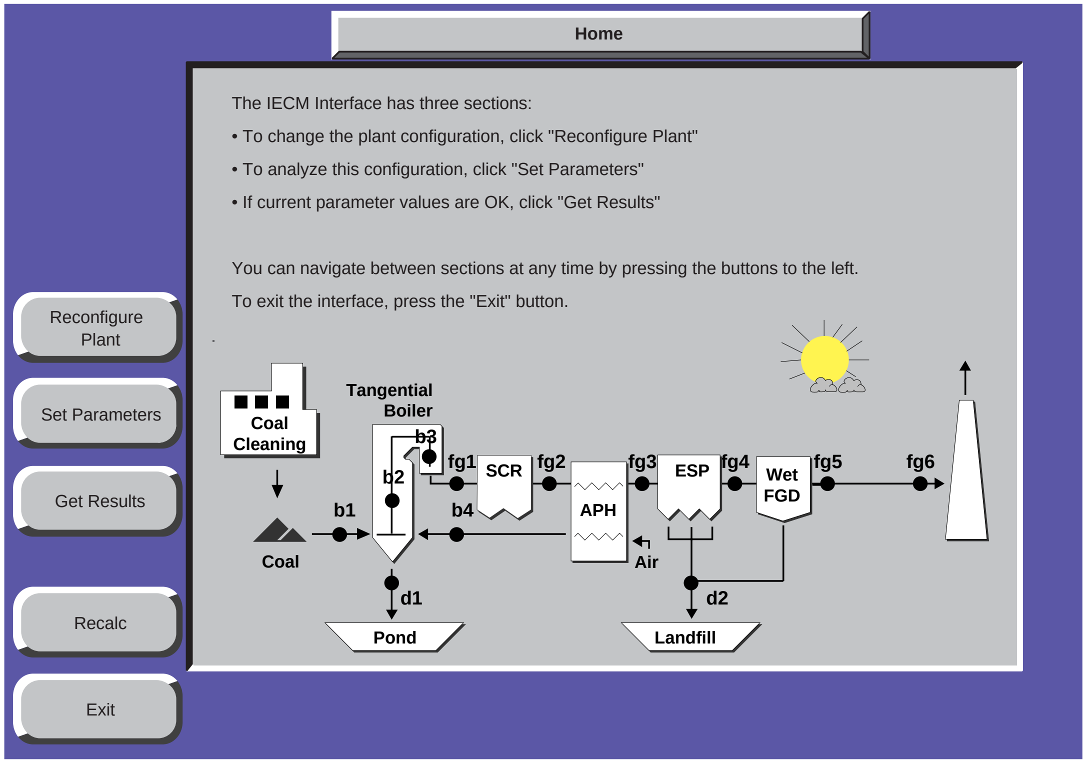

Figure 1. User interface screen showing the base case plant configuration

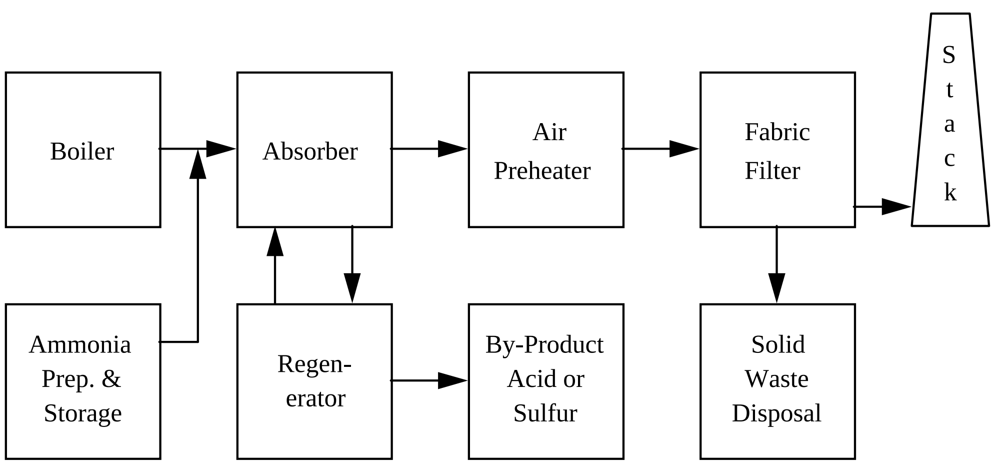

Figure 2. Coal-fired power plant design with a copper oxide emission control system

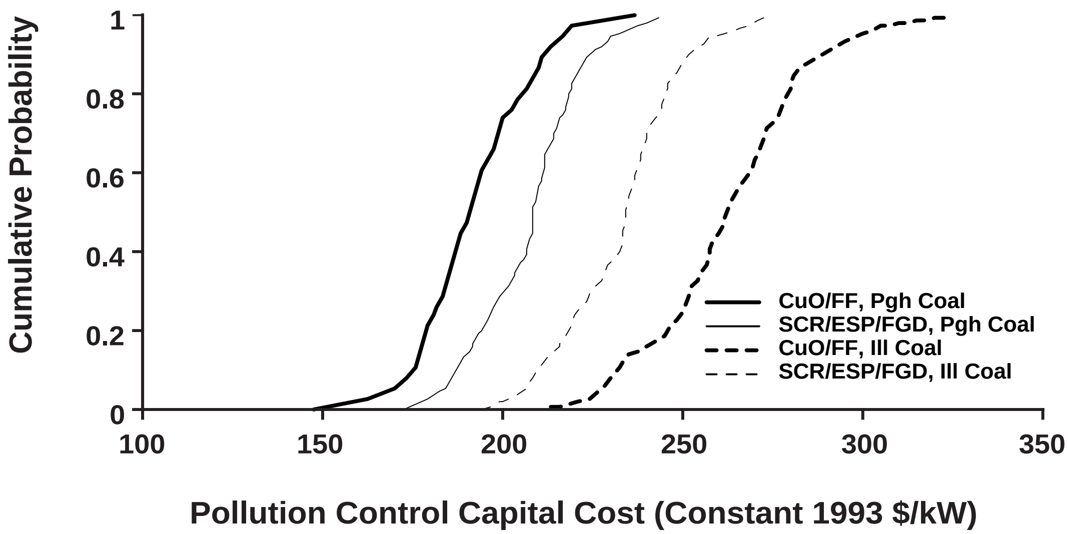

Figure 3. Total capital cost of conventional and advanced emission controls

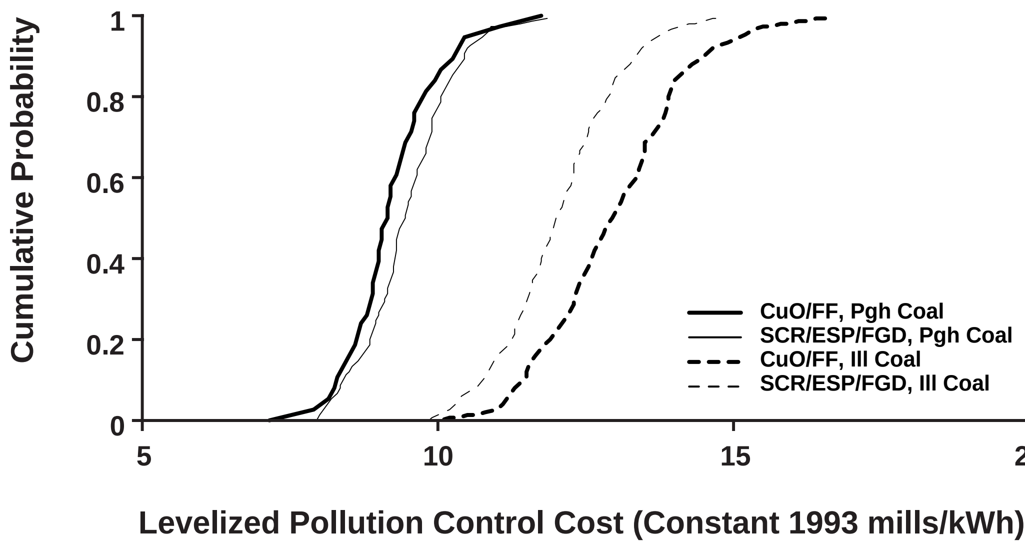

Figure 4. Total levelized cost of conventional and advanced emission controls

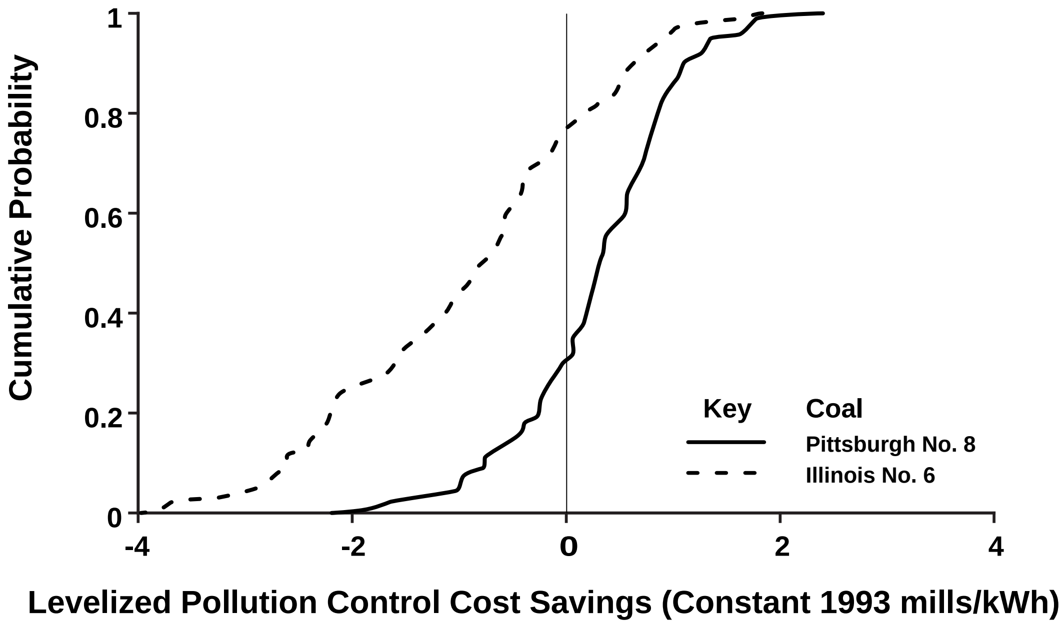

Figure 5. Savings of copper oxide system over base plant with SCR/ESP/FGD

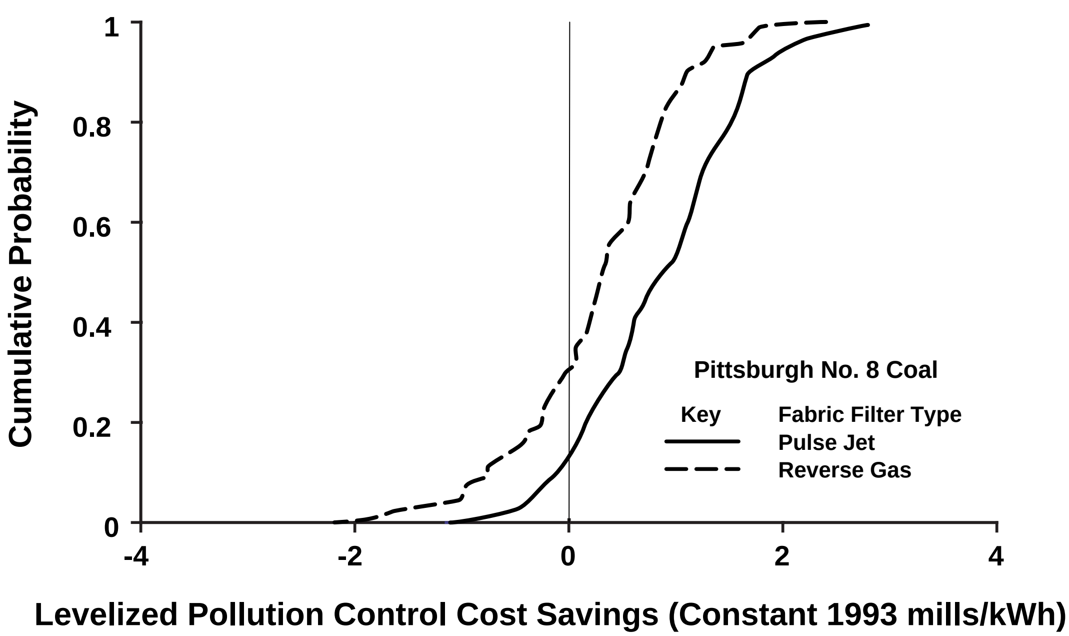

Figure 6. Effect of fabric filter choice on cost savings for copper oxide system