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IAPCS: A Computer Model that Evaluates Pollution Control Systems for Utility Boilers

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The IAPCS model, developed by U.S. EPA's Air and Energy Engineering Research Laboratory and made available to the public through the National Technical Information Service, can be used by utility companies, architectural and engineering companies, and regulatory agencies at all levels of government to evaluate commercially available technologies for control of SO_2, NO_x, and particulate matter emissions from coal-fired utility boilers with respect to performance and cost. The model is considered to be a useful tool to compare alternative control strategies to be used by utilities to comply with the requirements of the CAA, and to evaluate the sensitivity of control costs with respect to many of the significant variables affecting costs.

To illustrate the use of the model for site-specific studies, the authors used the model to estimate control costs for SO_2 and NO_x control at Detroit Edison's Monroe plant and two hypothetical plants under consideration and at three plants operated by New York State Electric and Gas Corporation. The economic and technical assumptions used to drive the model were those proposed by the utilities if cited, and if not cited, the model default values were used. The economic format and methodologies for costs cited in the Electric Power Research Institute's Technical Assessment Guide are used in the IAPCS model. Depending on the specific conditions and assumptions for the cases evaluated, SO_2 control costs ranged from \$417 to \$3,159 per ton of SO_2 removed, and NO_x control costs ranged from \$461 to \$3,537 per ton of NO_x removed or reduced.

The Integrated Air Pollution Control System (IAPCS)[1] computer model was developed for the U.S. Environmental Protection Agency's (EPA) Air and Energy Engineering Research Laboratory for analyzing air emission control systems applied to coal-fired utility boilers. The original version of IAPCS, developed about a decade ago, was an internal EPA mainframe model. Version II of the IAPCS, designed for an IBM-compatible personal computer, was published in September 1986.[2] Version II contained the essence of the Shawnee Flue Gas Desulfurization Computer Model,[3] a mainframe model developed by the Tennessee Valley Authority for EPA. Numerous upgrades and additions have been made to the model. The latest version, IAPCS 4.0, was used in a National Acid Precipitation Assessment Program study that estimated the costs of flue gas desulfurization (FGD) systems applied to 200 U.S. utility plants.[4] IAPCS 5.0, currently under development, is expected to be published in 1994.

Implications

The IAPCS model, developed by U.S. EPA's Air and Energy Engineering Research Laboratory can be used by utility companies and regulatory agencies to evaluate commercially available technologies for control of SO_2, NOx and particulate matter emissions from coal-fired utility boilers with respect to performance and cost. Although the model is not referred to in the Clean Air Act (CAA) or endorsed by the EPA, it is considered to be a useful tool to compare alternative control strategies to be used by utilities to comply with the requirements of the CAA.

This article focuses on the model's usefulness to utility companies evaluating pollution control options on utility boilers. In addition, utility companies could use the model for developing regulatory compliance strategies and sensitivity studies, and projecting future costs for planning purposes. Several other groups may find the IAPCS model useful as well. Federal and state legislators and regulators could use the model to estimate the economic, environmental, and energy impacts of different regulatory options. Architectural/engineering firms who design FGD systems, nitrogen oxide (NO_x) control systems, or particulate matter (PM) emission controls could use the model to prepare preliminary budget estimates for prospective clients as well as preliminary control system design. Public utility commissions could use the model for evaluating alternatives for pollution control in power production and, therefore, as a factor in determining electricity rates.

Federal and state regulations require utility boilers to meet limits on sulfur dioxide (SO_2) and NO_x emissions. Title IV of the Clean Air Act Amendments (CAAA) of 1990 targeted a 10 million ton[1] reduction of total utility boiler SO_2 emissions by the year 2000 from their 1980 emission levels. This goal is to be met through a two-phase strategy: Phase I requires 110 utility plants to reduce SO_2 emissions by 1995, and Phase II requires all utility boilers that serve generating units greater than 25 MW to reduce SO_2 emissions by the year 2000. In addition, the CAAA requires that EPA set limits on NO_x emissions for Phase I by May 1992 and Phase II by the year 1997. (The deadline for Phase I was extended; regulations were promulgated on March 22, 1994.)

The variety of SO_2 and NO_x reduction technologies available, coupled with the options of emissions allowance (1 allowance = 1 ton SO_2 emitted) banking and trading, makes choosing the most economical control methods a difficult decision for many utilities. The IAPCS model facilitates this decision-making process for utilities that burn coal. This article discusses the model's capabilities in providing cost and performance estimates for control technologies applied to "real-world" utility boilers.

To meet emission limits, utilities must consider one or more of the following options:

1. Switching to a less-polluting fuel (e.g., lower-sulfur coal or natural gas).
2. Implementing combustion modifications to inhibit pollution formation.
3. Installing post- and in-situ-combustion controls to remove pollutants from or prevent the formation of pollutants in flue gas.
4. Buying or trading emission allowances.
5. Practicing demand side management (DSM), or implementing renewable energy technologies.

The IAPCS model can assist utility companies in sorting out the economics of these options by providing cost and performance estimates for 15 SO_2, NO_x, and PM control technologies. In addition, IAPCS estimates the cost effectiveness (i.e., cost per ton of pollutant removed), which should help utilities make decisions on buying and trading allowances. IAPCS does not assist in evaluating DSM or renewable energy technologies.

Between 1989 and 1991, the IAPCS model was used by EPA and the National Park Service to conduct economic analyses intended to assess the cost to society for potential improvement of the visibility at the Grand Canyon National Park. Reduced visibility at the National Park was attributed to SO_2 emissions from three 750 MW coal-fired boilers at the Navajo Generation Station (NGS). Because each of the control options considered for the NGS represented an annualized cost exceeding $100 million, a Navajo retrofit was considered to be a major regulatory action, necessitating a Regulatory Impact Analysis under Executive Order 12291. The IAPCS model was used as an analytical tool to estimate the costs of SO_2 control at 70, 80, and 90 percent control using wet FGD, lime spray drying, and dry sorbent injection at the NGS.

This article discusses the use of the IAPCS model to evaluate pollution control options for Detroit Edison (DE) and New York State Electric and Gas Corporation (NYSEG). Each utility provided coal and design specifications for three of their existing or proposed generating units that are subject to regulation, and cited the particular control technologies to be evaluated by the IAPCS model. Since each utility specified its own design and economic assumptions, there is no common basis for comparison between them, and the designs are not purported to be optimum.

Description of the Integrated Air Pollution Control System Model

The IAPCS model is an interactive computer program that evaluates 15 SO_2, NO_x, and PM pollution control technologies for utility boilers. Version 4.0 is the current published version of the model;[1] Version 5.0 is under development. A developmental version of the model was used to produce the results shown herein, and are thus still subject to review and modification. Data input to the model reside in a parameter file containing values that the user can either accept or change. The default values in the input parameter file were chosen to reflect typical or average values. The parameter file includes boiler size and characteristics, coal composition, pollution control system design criteria, and economic assumptions. The user can choose one control system or several systems operating in an integrated fashion. If several systems are chosen, IAPCS will integrate the effects of each system into the material and energy balances and overall costs.

The results produced by the model are:

1. Summary of the boiler characteristics, coal composition, economic assumptions, and control system(s) chosen.
2. Description of the control system(s) design specifications, including values calculated by IAPCS;
3. Material and energy balance.
4. Controlled and uncontrolled emission summary.
5. Capital and operation and maintenance (O&M) costs summary using the Electric Power Research Institute's format presented in the Technical Assessment Guide.[5] and
6. The first year and levelized annual revenue requirements (LARR) and levelized cost per ton of pollutant removed.

The IAPCS model provides cost and performance estimates for the following 15 technologies:

Precombustion Controls: 1. Coal supply options (physical coal cleaning, coal switching/blending).

In-Situ Technologies: 2. Low NO_x combustion; 3. Limestone injection multi-stage burner (furnace sorbent injection) and the advanced silicate process (ADVACATE); 4. Natural gas reburning; 5. Integrated gasification combined cycle; 6. Pressurized fluidized bed combustion; 7. Pulverized coal-burning boiler (new powerplant costs); 8. Atmospheric fluidized bed combustion.

Postcombustion Technologies: 9. Lime spray drying; 10. Duct sorbent injection; 11. Gas conditioning; 12. Electrostatic precipitator; 13. Fabric filter; 14. Wet flue gas desulfurization; 15. Selective catalytic reduction.

The model is expected to produce cost estimates that are within 30 percent of the actual cost. A study conducted in 1990[6] indicated that for four of six real utility FGD systems studied, the IAPCS estimated cost was within four percent of the actual reported costs and the fifth system was within 21 percent, while the sixth system was 140 percent high due to abnormalities in the utility's cost estimates.

Generating Units, Coals, and Technologies Evaluated for the Two Utilities

Detroit Edison provided specifications for their Monroe plant and for two hypothetical new units (unspecified DE Units No. 2 and 3) that are under consideration for possible future construction. The NYSEG Corporation provided specifications for Milliken Units No. 1 and 2 and for Greenidge Unit No. 4. Specifications for these units are summarized in Table I.

Detroit Edison's Monroe plant is located in an area of Michigan designated as nonattainment for ozone and subject to regulation by the Michigan Department of Natural Resources (MDNR) as part of Michigan's State Implementation Plan. The plant is currently under consent order with the MDNR to meet an SO_2 limit of 1.6 lb/10^6 Btu. Because the Monroe plant is a Phase II unit, it must meet an average annual SO_2 emission tonnage limit by the year 2000 or obtain allowances to permit emissions above that limit. Monroe is not currently required to reduce NO_x emissions, but will have to meet the CAAA limits set for Phase II dry bottom, cell-wall-fired units in the year 2000. Monroe's NO_x limit may also be affected by the CAAA Title I ozone nonattainment NO_x requirements. The two hypothetical new DE units must meet New Source Performance Standards (NSPS) for both SO_2 and NO_x.

The three existing NYSEG units are located in New York State under the jurisdiction of the New York Department of Environmental Conservation (NYDEC). At the time of the writing of this article, the plants were under review by the NYDEC for possible regulation, but no state requirements had yet been set. The plants are Phase I units that must meet the CAAA SO_2 emission limit of 2.5 lb/10^6 Btu by 1995, unless granted an extension. In the year 2000, the units must meet the Phase II SO_2 tonnage limit.

Coal characteristics for economic analyses were provided by the utilities and are presented in Table II. Detroit Edison requested that control costs be estimated using different types of coal for their existing plant and their proposed new plants. These coals included a high-sulfur eastern (HSE) coal, a coal blend consisting of 50 percent mid-sulfur eastern coal and 50 percent low-sulfur western (LSW) coal. Detroit Edison has been increasing its use of LSW coal over the past 18 years.

The NYSEG Corporation requested that costs be evaluated for high- and low-sulfur coal. The specifications of the low-sulfur coal are not based on a specific coal. The low-sulfur coal price for NYSEG was based on the projected escalation of low sulfur coal costs over the next 25 years. The proposed coal compositions and costs for NYSEG are also presented in Table II.

Sulfur Dioxide Control Systems

Many different types of FGD systems have been developed and are in varying stages of commercial development. The main objectives of an FGD system are high SO_2 removal, high reliability, and low cost. Wet lime and limestone FGD systems are the oldest and most used systems in the United States and Europe. These systems can achieve 95 percent or greater SO_2 removal, and are reliable. However, their capital and operating costs are higher than for some other controls.

Much research and development effort has gone into designing lower cost systems. A promising new technology called the ADVACATE process is expected to achieve 90 percent SO_2 removal at a much lower cost than wet lime or limestone FGD. Although not yet commercially demonstrated, the process is now offered commercially by a major process supplier. The process consists of reacting lime, flyash, and water at about 90°C to produce a calcium silicate sorbent with very high surface area and absorptive capacity for SO_2. This moist sorbent (containing up to 40 percent moisture) has the properties of a dry sand and disperses easily in the flue gas by simply dropping it into the flue gas duct upstream of the PM control device, where it absorbs SO_2 and loses its moisture by evaporation. The dry spent sorbent containing calcium sulfite/sulfate and flyash is then removed by the PM control device.

Both utilities requested evaluation of wet lime or limestone FGD for their units, and specified the basis for the evaluation or used default values in the model. In addition, DE requested evaluation of ADVACATE for the existing DE unit. The NYSEG Corporation requested that one FGD system be applied to the two Milliken units. The specifications for the FGD systems are shown in Table III.

In the wet FGD process, lime or limestone slurry is circulated in spray towers located downstream of the PM control device where it contacts the flue gas stream and absorbs SO_2. Chemical additives can be used to improve the SO_2 absorption capacity of the slurry. Detroit Edison and NYSEG anticipate using adipic acid and formic acid, respectively, for SO_2 absorption enhance-

Table II. Coal characteristics.[a]

	Detroit Edison			New York State Electric and Gas Corp.	
	HSE Coal	Coal Blend	LSW	HSE	LS
HHV (Btu/lb)	12,500	11,050	9,300	12,600	13,000
Sulfur (%)	3.0	0.9	0.4	2.9	0.9
Ash (%)	9.8	4.9	3.9	11.0	11.0
Moisture (%)	5.9	15.0	24.2	5.0	5.0
Volatiles (%)	34.0	35.0	36.0	36.0	36.0
Fixed Carbon (%)	50.3	45.1	35.9	48.0	48.0
Cost ($/ton)b	30.90	26.58	20.75	48.13	65.78
Cost ($/$10^6$ Btu)	1.24	1.20	1.12	1.91	2.53

[a] Key: HSE = high-sulfur eastern; LSW = low-sulfur western; LS = low sulfur; HHV = higher heating value.

[b] Costs are in 1992 dollars for Detroit Edison and 1995 dollars for NYSEG.

Table I. Generating units, coal types, and technologies evaluated.[a]

	Detroit Edison			New York State Electric and Gas Corp.		
	Monroe	DE Unit No. 2	DE Unit No. 3	Milliken Unit No. 1	Milliken Unit No. 2	Greenidge Unit No. 4
Unit Size (MW)	750	600	300	157	161	108
Boiler Firing Method	Cell Wall	Wall	Wall	Tangential	Tangential	Tangential
Bottom Type	Dry	Dry	Dry	Dry	Dry	Dry
Existing or New	Existing	New	New	Existing	Existing	Existing
Capacity Factor (%)	73.9	73.9	73.9	85.0	83.0	79.0
Coal Types	HSE & CB	LSW	LSW	HSE & LS	HSE & LS	HSE
SO_2 Technologies Evaluated	Wet FGD	Wet FGD	Wet FGD	Wet FGD Coal Switch	Wet FGD Coal Switch	NA[b]
NO_x Technologies	LNC SCR	SCR	SCR	LNC	LNC	LNC

[a] Key: DE = Detroit Edison; HSE = high sulfur eastern; CB = coal blend; LSW = low sulfur western; LS = low sulfur; FGD = flue gas desulfurization; LNC = low NO_x combustion; SCR = selective catalytic reduction.

[b] NA = not applicable.

ment. The IAPCS model has provisions for estimating costs only with the optional adipic acid additive but, because the cost of either additive is a relatively small portion of operating costs (< 5 percent), it was assumed that adipic acid costs could be substituted for formic acid costs for the NYSEG estimates. For both utilities' systems, the option of bubbling compressed air through the effluent to oxidize the calcium sulfite to gypsum was assumed. This process, referred to as forced oxidation, allows better dewatering of the waste and with additional processing, makes it salable for use in wallboard manufacture. Even if it is not sold for wallboard manufacture, the lower water content makes the waste more mechanically stable, and thus may be more suitable for landfill.

The simplest option available to utilities for the reduction of SO_2 emissions is to switch to lower-sulfur fuels. This option was considered by both DE and NYSEG. Both utilities provided the specifications for a lower-sulfur coal than the base coal.

Switching to a lower-sulfur coal can require modifications to be made to the coal handling system, pulverizers, electrostatic precipitators, and boiler. The NYSEG Corporation provided the capital cost estimates they had calculated for switching Milliken Units No. 1 and 2 to low-sulfur coal. Detroit Edison has already begun switching its Monroe plant to a lower-sulfur coal blend. The IAPCS model was used to calculate the base coal operating costs and the low-sulfur coal operating costs for NYSEG. The incremental cost of burning the low sulfur coal was levelized and added to the levelized capital cost of boiler and pulverizer modifications to arrive at the LARR for coal switching at NYSEG.

Nitrogen Oxides Control Systems

Less options are available for NO_x control than for SO_2 control in the model. The three main options are:

Table III. Sulfur dioxide control system specifications.[a]

	Detroit Edison			New York State Electric and Gas Corp.
	Monroe	DE Unit No. 2	DE Unit No. 3	Milliken No. 1 & No. 2
User Inputs:				
Size (MW)	750	600	300	318 (combined)
Retrofit Factor (FGD)	1.4	1.0	1.0	1.41
Wet FGD Sorbent	Lime	Limestone	Limestone	Limestone
Wet FGD Additive	Adipic Acid	Adipic Acid	Adipic Acid	Formic Acid
Stoichiometric Ratio	1.15	1.15	1.15	1.04
Forced Oxidation	Yes	Yes	Yes	Yes
Scrubber Type	Spray Tower	Spray Tower	Spray Tower	Spray Tower
No. of Scrubber	2 Operating 1 Spare	2 Operating 1 Spare	1 Operating 1 Spare	1 Operating 0 Spare
Waste Disposal SO_2	Off-site	On-site	On-site	On-site
Removal (%)	98	70	70	95
IAPCS Calculated Values:				
Flue Gas Flow Rate (acfm)	2,562	2,222	1,111	910
L/G Ratio (gal/1000 acfm)	108.4	30.1	30.0	98.0
Pressure Drop (in. H2O)	7.0	5.1	5.1	6.8
Scrubber Outlet Temp (°F)	130	137	137	132

[a]Key: DE = Detroit Edison; FGD = flue gas desulfurization; IAPCS = Integrated Air Pollution Control System; L/G = liquid-to-gas ratio.

1. Low NO_x combustion (LNC)
2. Selective catalytic reduction (SCR)
3. Selective noncatalytic reduction (SNCR)

The combustion process associated with LNC is modified to suppress the formation of NO_x. Low NO_x combustion can be effected by replacing the conventional burners with low NO_x burners alone or in conjunction with overfire air ports installed above the existing air ports. Low NO_x combustion may achieve up to approximately 60 percent reduction of NO_x emissions, depending on site-specific conditions.

In an SCR system, ammonia is injected into the flue gas duct and then the flue gas is passed over a catalyst in a reactor vessel. The NO_x in the flue gas reacts with the ammonia and is reduced to nonpolluting elemental nitrogen. Selective catalytic reduction systems are either hot- or cold-side systems and either high- or low-dust, depending on where the reactor vessels are located in the flue gas stream. In hot-side, high-dust systems, the reactor vessels are upstream of the PM control device, between the economizer and the air heater. In hot-side, low-dust systems, the reactor vessels are downstream of a high temperature electrostatic precipitator, between the economizer and air heater. In cold-side, low-dust systems, the reactor vessels are downstream of the air heater, PM control device, and FGD system if the unit has one. SCR can achieve over 90 percent reduction of NO_x, but is usually designed for 80 percent reduction.

SNCR is similar to SCR with injection of ammonia or urea into the flue gas where the temperature is appropriate (1600-1900°F). The reaction between the ammonia and NO_x takes place at a higher

Table IV. NO_x control system specifications.[a]

	Detroit Edison		New York State Electric and Gas Corp.
	SCR (All Units)	LNC (Monroe)	LNC (All Units)
System Type	Cold-side	LNB + OFA	LNCFS I
NO_x Removal (%)	80	51[b]	25
Retrofit Factor	1.4	1.0[c]	1.0
Pressure Drop (in. H_2O)	7.0[b]	2.0	2.0
Catalyst Life (years)	3	NA[d]	NA
Stoichiometric Ratio (NH_3:NO_x)	0.82[b]	NA	NA
Ammonia Slipe (%)	1.99[b]	NA	NA
Ammonia Slipe (ppm)	4.4 - 5.1f	NA	NA

[a]Key:SCR = selective catalytic reduction; LNC = low NO_x combustion; LNB+OFA = low NO_x burners and overfire air; LNCFS I = Low NO_x Concentric Firing System I.

[b]IAPCS calculated values.

[c]LNC is a retrofit technology. IAPCS includes retrofit costs in its estimates.

[d]NA = not applicable.

[e]Value presented for ammonia slip is to be expected only when the catalyst is spent. With new catalyst, ammonia slip is much lower than values presented.

[f]Range results from the range of uncontrolled NO_x emissions from different coals.

temperature, without the use of a catalyst. SNCR can achieve up to 70 percent NO_x control, albeit with high levels of unreacted ammonia, but is usually designed for 50 percent NO_x reduction.

The current version of the IAPCS model will estimate costs for hot-side high-dust and cold-side low-dust SCR. The model does not currently provide estimates for SNCR; however, this option is planned for inclusion in the next version of IAPCS. Cost estimates for LNC in this paper are based on algorithms to be used in IAPCS version 5.0. These costs are significantly higher than those that would result from use of IAPCS version 4.0 (current published version), since version 5.0 is based on more recent information for burner retrofits.

Specifications for the NO_x control systems evaluated for the two utilities are provided in Table IV. Detroit Edison requested estimates for SCR and LNC applied to their existing Monroe plant and LNC for the new units. The DE Monroe unit has cell burners. The LNC system evaluated for DE uses both low NO_x burners and overfire air (LNB + OFA) to achieve 51 percent NO_x control. However, IAPCS does not distinguish this firing type from circular wall-fired burners when evaluating LNC, but it was used for an evaluation recognizing that costs and projected NO_x removal might not be achievable.

New York State Electric and Gas requested estimates for LNC applied to all three of their units. The system evaluated for NYSEG's tangentially fired boilers is referred to as Low NO_x Concentric Firing System I (LNCFS I). This system uses overfire air to achieve 25 percent NO_x control. More advanced systems of LNCFS (LNCFS II, LNCFS III) may achieve up to approximately 60 percent control.

The economic assumptions and cost rates for consumable items are provided in Table V. The IAPCS model will calculate carrying charge and levelization factors based on other inputs or the user can specify these factors. The model will escalate or deescalate costs to different year dollars based on either inflation or Chemical Engineering cost indices. Costs can be calculated in current or constant (zero inflation rate assumed) dollars.

Table V. Economic factors and cost rates.[a]

	Detroit Edison	New York State Electric & Gas Corp.
Economic Factors		
Current/Constant Dollars	Current	Current
Year of Capital Costs	1992	1992
Year of O&M Costs	1992	1995
Interest Rate (%)	—[b]	12.1[c]
Book Life (years)	—[b]	30
Tax Life (years)	—[b]	20
Inflation Rate (%)	—[b]	4
Depreciation Method	Straight Line/ ACRS[a]	Straight Line/ ACRS[a]
Capital Carrying Charge Factor	0.17296	0.1608[c]
O&M Cost Levelization Factor	1.693	1.44[c]
Cost Rates		
Operating Labor ($/hour)	32.76	33.74
Waste Disposal, Dry ($/ton)	7.57	9.96
Waste Disposal, Wet ($/ton)	8.75	10.94
Adipic Acid ($/ton)	1,774.00	NA[d]
Formic Acid ($/ton)	NA	1,040.00
Water ($/1,000 gal)	0.60	0.11
Steam ($/1,000 lb)	3.55	NA
Electricity ($/kWh)	0.06	0.02
Diesel Fuel ($/gal)	0.99	1.46
Lime ($/ton)	60.00	NA
Limestone ($/ton)	15.00	18.50
Catalyst ($/ft3)	413.88	NA
Ammonia ($/ton)	202.00	NA

[a]Key: ACRS = accelerated cost recovery system; O&M = operation and maintenance.

[b]— = Detroit Edison did not provide these values, but the carrying charge factor and O&M levelization factor result from assumption of these values.

[c]Calculated by IAPCS.

[d]NA = not applicable.

Results

Using input supplied by the two utilities and model default values where no input was supplied, the IAPCS model was used

Table VI. Wet flue gas desulfurization capital costs for Detroit Edison's Monroe plant burning high-sulfur Eastern coal.

Process Area	Capital Costs (1,000 $)
Material Handling	5,177
Feed Preparation	3,719
Gas Handling	9,894
SO_2 Scrubbing	40,039
Oxidation	1,346
Reheat	0
Solids Separation	6,291
Waste Disposal	0
Fan Addition/Modification	9,076
TOTAL PROCESS CAPITAL	**75,542**
General Facilities	7,554
Engineering	7,554
Project Contingency (32% of DC)	24,206
Process Contingency (1.2% of DC)	931
TOTAL PLANT COST	**115,787**
ALLOWANCE FOR FUNDS DURING CONSTRUCTION	**5,167**
TOTAL PLANT INVESTMENT	**120,954**
Royalty	0
Preproduction	4,801
Inventory	3,442
Initial Catalyst	0
Land	7
Demolition	1,511
TOTAL CAPITAL REQUIREMENT	**130,715**
TOTAL CAPITAL REQUIREMENT ($/kW)	**174.3**

to generate cost and performance estimates for the conditions specified. The output from IAPCS includes a breakdown of direct process area capital costs, indirect capital costs, operation and maintenance (O&M) costs, and total annual first year and LARR costs. The direct and indirect costs are shown for DE's 750 MW unit with HSE coal in Table VI and the O&M costs for this unit are shown in Table VII.

Cost estimates provided in this section include the cost of electricity used by the control system. However, the replacement cost of that power is not included. This replacement power may be bought from another utility at a higher cost rate than it costs DE or NYSEG to produce. If DE or NYSEG had to build a power plant to supply the replacement power, part of the cost of that new power plant could be assigned to supplying replacement power for the control systems. The effect of bonus allowances also was not considered in the cost estimates.

Table VII. Wet flue gas desulfurization operation and maintenance costs for Detroit Edison's Monroe unit burning high-sulfur eastern coal.[a]

	Annual Usage or Basis	Rate	Annual Cost[b] (1,000 $/yr)
Fixed O&M Costs			
Operating Labor (labor hrs)	65,200	$32.76	$2,136
Analysis Labor (labor hrs)	6,110	$32.76	$200
Maintenance Labor	1.51% of TPC	NA[c]	$1,746
Maintenance Materials	2.26% of TPC	NA	$2,619
Admin. & Support Labor	30% of O&M Labor	NA	$1,225
Total Fixed O&M Costs			$7,926
Consumables			
Solid Disposal, Wet (tons)	398,000	$8.75	$3,482
Adipic Acid (tons)	269	$1,773.62	$477
Water (1,000 gal)	256,000	$0.60	$154
Electricity (kWh)	67,900,000	$0.06	$4,074
Lime (tons)	118,000	$60.00	$7,080
Total Variable O&M Costs			$15,267
Total 1st Year O&M Costs			$23,193
Levelized Annual Costs		Cost[b]	
Total Levelized O&M Costs (Levelization Factor = 1.69)		$39,266	
Annual Capital Charge (Capital Charge Factor = 0.173)		$22,609	
Levelized Annual Revenue Requirements		$61,875	
Levelized Annual Revenue Requirements (mills/kWh)		12.7	
Levelized Cost Per Ton of SO_2 Removed ($/ton)		$563[d]	

[a]Key: O&M = operation and maintenance; labor hrs = labor hours; TPC = total plant costs.

[b]In thousands of dollars, except where noted. All costs are in 1992 dollars.

[c]NA = not applicable.

[d]Estimate does not include replacement electricity costs.

Some of the many possible SO_2 control alternatives for the two companies are compared in Table VIII without the individual details shown in Tables VI and VII for FGD. For comparison of the different SO_2 control systems with the different coals, Table VIII shows direct costs, indirect costs, O&M costs, LARR, uncontrolled and controlled emissions, total annual costs on a mills/kWh basis, and cost per ton of SO_2 removed. This table shows that for DE's three units, total levelized costs for wet FGD range from 6.6 to 12.7 mills/kWh. The range in costs is attributable to different unit sizes, retrofit difficulty for the existing unit, the difference in sulfur content of the coals, and the different removal efficiencies for the new and existing units. The ADVACATE process offers a much lower cost on the Monroe unit at 4.0 mills/kWh.

Detroit Edison's existing Monroe plant must meet SO_2 limits of 1.6 lb/10^6 Btu set by consent order from the MDNR and an annual tonnage limit by the year 2000 set by the CAAA. The 1.6 lb/10^6 Btu emission rate can be met by burning the coal blend, which yields an uncontrolled emission rate of 1.55 lb/10^6 Btu. The Monroe unit has in fact been converted to burning the coal blend. Modifications to the coal mills and boiler to fire the coal blend have cost an estimated $16.4 million. This cost has been offset by the lower cost of the coal blend. The coal cost situation at DE is very unusual in that the cost of lower sulfur coal blend is cheaper than the high sulfur coal in terms of $/$10^6$ Btu. Thus, there is no logical tradeoff of FGD with HSE coal versus coal switching to a lower sulfur coal.

Wet FGD at 98 percent control and ADVACATE at 90 percent control result in controlled SO_2 emissions lower than the regulatory requirement, although ADVACATE is not a commercially demonstrated process at present. By achieving more control than the regulations require, the utility would have the option of selling or banking the SO_2 allowances created by removing more SO_2 than is required. Knowing the cost per ton of SO_2 removed helps utilities make the most economical choice for control efficiency. Utilities want to achieve the highest efficiency on units where the cost per ton of pollutant removed is lowest, and use the extra tons of SO_2 removed (allowances) to offset emissions at units where the control cost is higher. Alternatively, these extra tons of SO_2 removed (allowances) could be sold to other utilities, under the provisions of the 1990 CAAA.

Detroit Edison would use LSW coal in the new 300 MW and 600 MW units they are considering in future expansion plans. These units would be subject to federal NSPS and the Michigan SIP, thus requiring at least 70 percent SO_2 removal depending on the controlled emission rate. Such new units would not receive SO_2 allowances.

English to Metric Conversions

1 acfm	=	0.0005 m^3/s
1 Btu	=	1,055 joules
1 Btu	=	0.0003 kWh
1 10^6 Btu/hr	=	293.1 kW
1 ft^3	=	0.0283 m^3
1 gal	=	3.7854 liters
1 in.	=	2.54 cm
1 lb	=	0.4536 kg
1 ton	=	0.9072 metric ton
°F	=	1.8°C + 32

For NYSEG's units, wet FGD costs less than switching to the lower-sulfur coal, while at DE's Monroe Unit the reverse is true. For Milliken Units No. 1 and 2, Table VIII shows a LARR of 8.5 mills/kWh for wet FGD versus 9.6 mills/kWh for coal switching. The NYSEG Corporation estimates that $10 million would be required to modify the two units to allow them to burn the low-sulfur coal. This capital cost associated with boiler modifications for the coal switch, in addition to the higher cost of the low-sulfur coal, make the wet FGD system a cheaper alternative for NYSEG. The NYSEG Corporation has begun construction of a wet FGD system at Milliken.

The NYSEG units could meet the Phase I 1995 SO_2 limit of 2.5 lb/10^6 Btu either with wet FGD or by burning low-sulfur coal. The controlled SO_2 emission rate for the LS coal of 1.4 lb/10^6 Btu is not sufficient to meet the Phase II requirements. To meet the Phase II SO_2 emission limit requires a greater than 72 percent reduction, which is more than the low-sulfur coal achieves. If low-sulfur coal were used to meet the Phase I limit, additional scrubbing would be required to meet the Phase II limit unless a lower-sulfur coal than the one evaluated in this study were used.

Costs and emissions for NO_x control technologies for both companies are shown in Table IX. The uncontrolled NO_x rates were estimated by IAPCS. For DE, costs for SCR range from 12.3 to 13.3 mills/kWh. It is expected that Version 5.0 of the model will estimate considerably lower SCR costs than this developmental version. For the Monroe unit, LNC offers a much less costly alternative at 1.1 mills/kWh. For NYSEG, LNC costs range from 0.66 to 0.93 mills/kWh (estimates for SCR were not made for NYSEG). Although not shown here, additional analyses could have been conducted to estimate the cost and performance of combined LNC and SCR.

Detroit Edison's Monroe unit could meet the proposed CAAA NO_x limit of 0.5 lb/10^6 Btu for wall-fired units using either LNC or SCR. However, Monroe is a cell burner unit for which a NO_x limit has not yet been set. The NO_x reduction estimated by IAPCS for LNC applied to Monroe of 51 percent may not be achievable for cell burner units.

At the time of the writing of this paper, Detroit Edison's proposed new units would have had to meet 1979 NSPS NO_x requirements, which were set at 0.6 lb/10^6 Btu for bituminous

Table VIII. Comparison of sulfur dioxide control costs.[a]

	Detroit Edison					New York State Electric and Gas Corp.	
Unit	Monroe	Monroe	Monroe	DE Unit No. 2	DE Unit No. 3	Milliken No. 1 & No. 2	
Coal	HSE Coal	Coal Blend	Coal Blend	LSW Coal	LSW Coal	HSE Coal	LS Coal
Control System	Wet FGD	Wet FGD	ADVACATE	Wet FGD	Wet FGD	Wet FGD	Coal Switch
Size (MW)	750	750	750	600	300	318	318
Direct Process Area Costs (1,000 $)b	75,542	73,045	21,710	39,468	25,037	37,900	NA[c]
Indirect Costs (1,000 $)	55,173	50,541	22,486	25,546	16,755	19,553	NA
Total Capital Requirement (1,000 $)	130,715	123,586	44,196	65,014	41,792	57,453	10,000
Total Capital Requirement ($/kW)	174.3	164.8	58.9	108.4	139.3	180.7	31.4
First Year O&M Costs (1,000 $/year)	23,193	15,816	6,865	8,461	5,179	7,439	14,489
Levelized Annual Revenue Req. (1,000 $/year)	61,875	47,305	19,266	25,569	15,996	19,922	22,472
Levelized Annual Revenue Req. (mills/kWh)	12.74	9.74	3.97	6.58	8.24	8.51	9.60
Coal Rate (ton/hr @ full load)	296.1	335.0	335.0	318.4	159.2	120.9	117.2
Uncontrolled SO_2 Emissions (lb/hr @ full load)	34,644	11,169	11,169	4,470	2,235	13,674	13,674[d]
Capacity Factor (%)	73.9	73.9	73.9	73.9	73.9	85	83
Uncontrolled SO_2 Emissions (tons/yr @ CF)	112,136	36,152	36,152	14,469	7,234	50,309	50,309[d]
Uncontrolled SO_2 Emissions (lb/106 Btu)	4.80	1.55	1.55	0.77	0.77	4.60	4.60d
SO_2 Reduction (%)	98.0	98.0	90.0	70.0	70.0	95.0	69.0
Controlled SO_2 Emissions (ton/yr)	2,243	723	3,615	4,341	2,170	2,515	15,596
Controlled SO_2 Emissions (lb/10^6 Btu)	0.10	0.03	0.15	0.23	0.23	0.23	1.43
SO_2 Reduction (tons/yr)	109,894	35,429	32,537	10,128	5,064	47,794	34,713
Cost Per Ton of SO_2 Removed ($/ton)e	563	1,335	592	2,525	3,159	417	647

[a]Key: HSE = high sulfur eastern; FGD = flue gas desulfurization; DE = Detroit Edison; LSW = low-sulfur western; LS = low sulfur; CF = capacity factor.

[b]All costs are in 1992 dollars except NYSEG O&M costs which are in 1995 dollars.

[c]NA = not available.

[d]Uncontrolled emissions for LS coal are assumed to be equal to uncontrolled HSE coal emissions.

[e]Estimates do not include replacement electricity costs or bonus allowance credits.

Table IX. Comparison of NO_x control costs.[a]

	Detroit Edison				New York State Electric and Gas Corp.		
Unit	Monroe	Monroe	DE Unit No. 2	DE Unit No. 3	Milliken No. 1	Milliken No. 2	Greenidge No. 4
Coal	Coal Blend	Coal Blend	LSW Coal	LSW Coal	HSE Coal	HSE Coal	HSE Coal
Control System	LNC	SCR	SCR	SCR	LNC	LNC	LNC
Size (MW)	750	750	600	300	157	161	108
Direct Process Area Costs (1,000 $)[b]	11,971	46,868	30,774	18,299	2,276	2,300	2,002
Indirect Costs (1,000 $)	8,559	79,954	53,385	30,986	1,125	1,138	1,089
Total Capital Cost (1,000 $)	20,530	126,822	84,159	49,285	3,401	3,438	3,091
Total Capital Cost ($/kW)	27.4	169.1	140.3	164.3	21.7	21.4	28.6
First Year O&M Costs (1,000 $/yr)	1,066	25,101	19,689	10,218	160	161	136
Levelized Annual Revenue Req. (1,000 $/yr)	5,355	64,431	47,893	25,825	776	784	693
Levelized Annual Revenue Req. (mills/kWh)	1.10	13.27	12.33	13.30	0.66	0.67	0.93
Coal Rate (ton/hr @ full load)	296.1	335.0	318.4	159.2	59.7	61.2	41.1
Uncontrolled NO_x Emissions (lb/hr @ full load)	7,034	7,034	6,686	3,343	895	918	616
Capacity Factor (%)	73.9	73.9	73.9	73.9	85	83	79
Uncontrolled NO_x Emissions (tons/yr @ stated CF)	22,768	22,768	21,641	10,821	3,332	3,337	2,239
Uncontrolled NO_x Emissions (lb/10^6 Btu)	0.95	0.95	1.13	1.13	0.60	0.60	0.60
NO_x Reduction (%)	51.0c	80.0	80.0	80.0	25.0	25.0	25.0
Controlled NO_x Emissions (ton/yr)	11,156	4,554	4,328	2,164	2,499	2,503	1,680
Controlled NO_x Emissions (lb/10^6 Btu)	0.47	0.19	0.23	0.23	0.45	0.45	0.45
NO_x Reduction (tons/yr)	11,612	18,241	17,313	8,657	833	834	560
Cost Per Ton of NO_x Removed ($/ton)[d]	461	3,537	2,766	2,983	932	940	1,238

[a]Key:LNC = low NOx combustion; SCR = selective catalytic reduction; LSW = low sulfur western; DE = Detroit Edison; HSE = high-sulfur eastern; FGD = flue gas desulfurization; LSW = low-sulfur western; LS = low sulfur; CF = capacity factor.

[b]1000 $ = in thousands of dollars.

[c]Estimated NOx reduction for wall-fired units with low NO_x burners and overfire air.

[d]Costs do not include replacement electricity costs or bonus allowance credits.

coal. The CAAA requires the NSPS NO_x limit to be revised by 1994. Low NO_x combustion may not achieve the new NO_x limit; therefore, SCR or SNCR may be required for DE's hypothetical new units.

All three of NYSEG's units could meet the proposed (when this paper was written) CAAA NO_x limit of 0.45 lb/10^6 Btu for tangentially fired boilers using LNC to achieve 25 percent control. The uncontrolled NO_x emission rate of 0.6 lb/10^6 Btu was estimated by IAPCS. If NYSEG wanted to achieve greater NO_x reduction, more advanced LNCFS control systems could be installed.

Conclusions

The IAPCS model offers utilities a tool for analyzing different control options to meet SO_2, NO_x, and PM emission regulations. It provides cost and emission estimates for those controls and can help to narrow the choices available for each type of control. It allows the user to obtain estimates of control systems for site-specific boilers and coal types using different economic and control technology parameters. It also allows the user to easily change system parameters to analyze the effects of these changes on system performance and cost and thus conduct sensitivity analyses of costs with respect to any parameter or group of parameters. For example, the model could be used to estimate costs for SO_2 control with coals containing 1.0, 1.5, 2.0, and 2.5 percent sulfur in terms of mills/kWh and $/ton of SO_2 removed. The IAPCS model may prove especially useful to utilities trying to make decisions regarding CAAA requirements because of the large number of boilers that will require SO_2 and NO_x controls, and the potential effect of the market for allowance trading and banking.

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