RETROFIT COSTS OF SO_2 AND NO_x CONTROL AT 200 U.S. COAL-FIRED PLANTS

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ABSTRACT

This paper presents the results of a study conducted under the National Acid Precipitation Assessment Program by the U.S. Environmental Protection Agency's Air and Energy Engineering Research Laboratory. The objective of this research program was to significantly improve engineering applying cost estimates currently being used to evaluate the economic effects of applying sulfur dioxide (SO_2) and nitrogen oxide (NO_x) controls at 200 large SO_2 emitting coal-fired utility plants. To accomplish the objective, procedures were developed and used that account for site-specific retrofit factors. The site-specific information was obtained from aerial photographs, generally available data bases, and input from utility companies. Cost results are presented for the following control technologies: lime/limestone flue gas desulfurization, lime spray drying, coal switching, furnace and duct sorbent injection, low NO_x combustion or natural gas reburn, and selective catalytic reduction. Although the cost estimates provide useful site-specific cost information on retrofitting acid gas controls, the costs are estimated for a specific time period and do not reflect future changes in boiler and coal characteristics (e.g., capacity factors and fuel prices) or significant changes in control technology cost and performance.

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INTRODUCTION

The primary objective of the National Acid Precipitation Assessment Program (NAPAP) study of 200 U.S. coal-fired power plants was to improve cost estimates for retrofitting flue gas desulfurization (FGD) controls at 200 of the largest SO_2 emitting coal-fired power plants in the 31 eastern states. This study is probably the most comprehensive conducted to date that evaluates boiler-specific retrofit factors for large coal-fired power plants in the above cited region. The results may be used for broad analysis of the cost of controlling acid rain precursors.

Figure 1 shows the phases in which the NAPAP study of 200 plants was conducted. In Phase I, detailed, site-specific procedures were developed with input from the technical advisory committee. In Phase II, these procedures were used to evaluate retrofit costs at 12 plants based on data collected from site visits. Based on the results of this effort, simplified procedures were developed to estimate site-specific costs without conducting site visits. In Phase III, the simplified procedures were verified or modified based on utility input by visiting 6 of the 50 plants. The modified procedures were then used to estimate retrofit costs at the remaining 138 plants. In Phase IV, utility comments were incorporated into the final 200-plant study report. Table 1 presents the commercial and developmental SO_2 and NO_x control technologies evaluated under the NAPAP program.

COST METHODOLOGY

For each plant, a boiler profile was developed based either on site visits or from sources of public information; the primary public source was Energy Information Administration (EIA) Form 767. Additionally, boiler design data were obtained from Powerplants Database magazine [1], and aerial photographs were obtained from state and federal agencies. The plant and boiler profile information was used to develop the input data for the performance and cost models. All of the cost estimates were developed using the Integrated Air Pollution Control System (IAPCS) cost model [2]. Figure 2 presents the methodology used to develop IAPCS inputs to estimate site-specific costs of retrofitting SO_2 controls. The site-specific information sources were used to develop process area retrofit multipliers, scope adder costs, and boiler/coal parameters. This information was input to the IAPCS cost model which generated the capital, operating and maintenance (O&M), and levelized annual costs of control and the emission reductions. The use of process area retrofit difficulty multipliers and scope adder costs to adjust generic cost model outputs to reflect site-specific retrofit situations was derived from an EPRI report [3].

COST ESTIMATES FOR U.S PLANTS

Table 2 summarizes the economic bases used to develop the cost estimates. The economic bases used in this study are not necessarily those that would be used currently or by a utility company. This study was conducted between 1985 and 1990. Economic assumptions such as inflation rate, cost of money, cost of consumables, and expected plant life may be expected to vary with time. These parameters are from the 1986 EPRI Technical Assessment Guide [4] escalated to 1988 dollars. The number of boilers varied for each control technology because in some cases technology application was technically not feasible. There were 631 boilers evaluated in the 200 plants.

For each control technology, the following three figures are presented: capital cost (dollars/kilowatt), levelized annual costs (mills/kilowatt hour), and cost per ton of SO_2 removed (dollars/ton) each plotted versus the sum of controlled megawatts. The x-axis (sum of megawatts) is the cumulative sum of the boiler size sorted in order from the lowest to the highest cost to control. Also identified on each curve are the 25, 50, and 75 sum of megawatt percent points for the boilers included in the figure. Each point on the curve represents a specific boiler cost result. The first point represents the boiler that had the lowest capital cost and unit cost. The last point represents the boiler that had the highest cost. The curves turn up sharply because each curve was developed starting with the boiler having the lowest control cost and ended with the boiler having the highest control cost. The cost results <u>do</u> <u>not</u> represent the average or cumulative cost of control.

Costs developed in this report are based on economic assumptions which may not represent a particular utility company's economic guidelines. The cost results are static (not dynamic) and represent a single figure (1985 base year or other figures specified by the individual utility company) with regard to capacity factor, coal sulfur, and pollution control characteristics.

<u>FGD Costs Estimates</u>

Figures 3 through 5 summarize the cost estimates developed for wet lime/limestone (L/LS) FGD for 449 boilers. Two FGD configurations were evaluated: a conventional

New Source Performance Standard (NSPS) design having a single system for each boiler, small absorber size (125 MW or less), and one spare absorber; and a low-cost design that does not have a spare absorber, uses larger absorber sizes when feasible (up to 300 MW), and combined boiler systems when feasible.

Cost estimates for FGD were developed for only 449 of 631 boilers because 46 boilers were already equipped with FGD systems, 130 boilers were burning low sulfur coals (many are 1971 NSPS units), and 6 boilers were too small or about to be retired. The percent increase in capital cost for retrofitting an FGD system over a typical new plant installation ranged from 19 to 100 percent, with the average being 45 percent.

Figures 6 through 8 summarize the cost estimates for lime spray drying (LSD) for all the boilers for which costs were developed. Two control options were considered for the retrofit of this technology: reuse of the existing electrostatic precipitator (ESP) or installation of a new fabric filter (FF). Reuse of the existing ESP was not considered for the following boiler situations: when the specific collection area (SCA) of the existing ESP was small (< 220 ft^2/1000 actual ft^3/min)[1], and when the addition of new plate area was impractical (e.g., roof-mounted ESPs).

In such cases, a new FF was used for particulate matter control with the spray drying system. If a unit is burning high sulfur coal (greater than 3 percent sulfur), LSD with a new FF was not considered because it was assumed that wet FGD would be economically more attractive. Based on the cited criteria, 168 boilers were considered with a new FF option, and 195 boilers were considered with reuse of existing ESPs.

For wet L/LS FGD, the characteristics of the low, mid, and high unit cost boilers are:

	Low $/ton	Mid $/ton	High $/ton
Size, MW	496	194	100
Coal Sulfur, percent	2.4	2.4	1.0
Capacity Factor	33.0	56	6
Retrofit Difficulty	1.38	1.54	1.84

[1]It is EPA policy to use metric units. English units are used in this paper because they are familiar to readers. Metric conversion factors are given at the end of this paper.

For LSD FGD, the boiler characteristics of the low, mid, and high unit cost boilers are:

	Low $/ton	Mid $/ton	High $/ton
Size, MW	280	176	100
Coal Sulfur, percent	4.2	1.9	1.0
Capacity Factor	76	75	6
Retrofit Difficulty	1.23	1.55	1.87
Existing ESP or New Fabric Filter	ESP	ESP	FF

Coal Switching Cost Estimates

For coal switching (CS), two fuel price differentials (FPDs) were evaluated: $5/ton and $15/ton. The $5 to $15/ton FPD was assumed to represent an estimated range for the FPD after passage of acid rain legislation. The CS cost estimates are highly dependent upon the FPD. The impacts of particulate matter control upgrades and coal handling upgrades are generally small by comparison. Figures 9 through 11 summarize the costs for 329 boilers in the 200 plants for which costs were developed for CS. CS was not considered for some units because the units either already burn a low sulfur coal or have wet bottom boilers that can burn only coals with special ash fusion properties. Capital costs for coal switching are predominantly from coal inventory capital costs (30- to 60-day coal inventory cost difference).

For coal switching, assuming a $15 per ton FPD, the low, mid, and high cost boilers are:

	Low $/ton	Mid $/ton	High $/ton
Size, MW	496	900	497
Coal Sulfur, percent	2.4	1.9	1.1
Capacity Factor	33	76.2	43

Sorbent Injection Cost Estimates

Two sorbent injection technologies in active research and development were evaluated in this study: 1) duct spray drying (DSD) and 2) furnace sorbent injection (FSI) with humidification. Figures 12 through 17 summarize the cost estimates developed for these technologies.

Some boilers were not considered good candidates for these technologies because:

- FSI and DSD were not considered practical for boilers having an ESP SCA of <220 ft^2/1000 acfm,[2]
- DSD was not considered if the duct residence time from the injection point after the air heater to the ESP inlet was less than 2 sec (<100 ft of duct length), and
- FSI was not considered feasible for wet bottom and down-fired boilers.

Only 321 boilers were considered appropriate for DSD, and 289 were considered for FSI applications. The costs presented for FSI assume 50 and 70 percent SO_2 control with humidification to bracket the expected removal rate. No design parameter changes were assumed to achieve either 50 or 70 percent SO_2 removal. Costs presented for DSD assume 50 percent SO_2 reduction.

For sorbent injection, the boiler characteristics of the low, mid, and high unit cost boilers are:

	Low $/ton	Mid $/ton	High $/ton
Size, MW	496	585	23
Coal Sulfur, percent	2.4	1.2	1.3
Capacity Factor	33	56	20
Existing ESP or New Fabric Filter	ESP	ESP	ESP

Low NO_x Combustion Cost Estimates

Figures 18 through 20 summarize cost estimates for application of low NO_x burner (LNB) technology on dry bottom wall-fired boilers (20-55 percent NO_x reduction), overfire air (OFA) on tangential-fired boilers (10-35 percent NO_x reduction), and natural gas reburn (NGR) on all other boiler firing types (60 percent NO_x reduction). However, for boilers where NGR is applied, the unit costs are \$400 to \$1100 per ton of NO_x removed. This is due to the cost of natural gas relative to coal (assumed to be \$2 per million Btu in 1988 dollars). For this study, 228 boilers were candidates for LNB, 214 boilers for OFA, and 81 boilers for NGR. Some of the boilers were not considered for low NO_x combustion technologies because of the reservations of plant personnel regarding applicability of these technologies.

For low NO_x combustion, the boiler characteristics of the low, mid, and high unit cost boilers are:

	Low \$/ton	Mid \$/ton	High \$/ton
Size, MW	865	626	30
Capacity Factor	79	65	5
LNC Type	OFA	OFA	LNB

Selective Catalytic Reduction (SCR) Cost Estimates

Figures 21 through 23 summarize the cost estimates for application of SCR. For most of the units, cold-side, tail-end systems were assumed (the reactor downstream of the particulate control or scrubber). In some instances, due to space availability limitations or the unit's being equipped with a hot-side ESP, a hot-side, high-dust system configuration was used (the reactor between the economizer and the air heater). Use of the tail-end system minimizes unit downtime, which reduces the uncertainty of estimating the cost of replacement power, and maximizes the catalyst life. However, a significant energy penalty is associated with flue gas reheating, compared to a hot-side system (equivalent to $120^{o}F$ reheat). This cost was not included in this study because the early version of IAPCS model did not estimate this cost. Reheat costs estimated by the most recent version of IAPCS increase the annual cost of control by 20 to 30 percent for cold-side systems. For this study, 624 boilers were evaluated for SCR retrofit.

For SCR, the boiler characteristics of the low, mid, and high unit cost boilers are:

	Low $/ton	Mid $/ton	High $/ton
Size, MW	217	543	25
Capacity Factor	94	49	2
Retrofit Difficulty	1.34	1.34	1.52
Hot-Side/Cold-Side	Cold-Side	Cold-Side	Cold-Side

CONCLUSION

For each SO_2 and NO_x control technology evaluated under this study, different factors affected control cost and performance estimates for retrofit applications at coal-fired boilers. Table 3 identifies those factors found to have the most significant effects.

The cost and performance information presented is a realistic guide regarding the degree of retrofit difficulty for each control option evaluated. However, as noted in Table 1, the technologies evaluated in this study are at various stages of commercial development. There is a higher degree of uncertainty regarding the cost and performance of those technologies that do not have extensive commercial application in the U.S. Therefore, no attempt has been made in this study to identify a best option for each plant/boiler.

Additionally, a utility company's decision concerning which retrofit control to apply to a given boiler is very complex. The data contained in this report can provide guidance in selecting the least-cost control options for specific plants/boilers for various planning scenarios. The information can also be used by technology developers to identify market niche and cost and performance goals. Studies are currently ongoing to evaluate the market niche for two advanced sorbent injection technologies and several advanced combustion technologies.

REFERENCES

1. Elliot, T. C., ed. Powerplants Database, Details of the Equipment and Systems in Utility and Industrial Powerplants, 1950-1984. McGraw-Hill, Inc., New York, New York, 1985.

2. Palmisano, P. J., and B. A. Laseke. User's Manual for the Integrated Air Pollution Control System Design and Cost-Estimating Model, Version II, Volume I. EPA-600/8-86-031a (NTIS PB87-127767), U.S. Environmental Protection Agency, Research Triangle Park, North Carolina, September 1986.

3. Shattuck, D. M., et al. Retrofit FGD Cost Estimating Guidelines. EPRI Report CS-3696, Electric Power Research Institute (EPRI), Palo Alto, California, 1984.

4. Electric Power Research Institute. Technical Assessment Guide (TAG), Volume 1. Electricity Supply--1986. EPRI Report P-4463-SR, Palo Alto, California, 1986.

CONVERSION FACTORS:

1 acfm = 0.000472 actual m^3/sec

1 acre = 4046.9 m^2

1 Btu = 0.2520 kg-cal

^oF = ^oC x 9/5 + 32

1 ft = 0.3048 m

1 ft^2 = 0.0929 m^2

1 gal. = 3.785 liters

1 ton = 907 kg

TABLE 1. EMISSION CONTROL TECHNOLOGIES EVALUATED

	Species Controlled		Development Status		
	SO_2	NO_x	Commercial	Limited Commercial Experience	Ongoing Or Near Demonstration
Lime/limestone (L/LS) flue gas desulfurization (FGD)	X		X		
Additive enhanced L/LS FGD	X		X		
Lime spray drying (LSD) FGD[a]	X		X		X
Physical coal cleaning (PCC)	X		X		
Coal switching and blending (CS/B)	X		X		
Low-NO_x combustion (LNC)		X		X	
Furnace sorbent injection (FSI) with humidification	X				X
Duct spray drying (DSD)	X				X
Natural gas reburning (NGR)[b]	X	X			X
Selective catalytic reduction (SCR)		X		X	
Fluidized bed combustion (FBC) or coal gasification (CG) retrofit[c]	X	X		X	

[a]Commercial on low-sulfur coals; demonstrated at pilot scale on high sulfur coals.

[b]For wet bottom boilers and other boilers where LNC is not applicable.

[c]Evaluated qualitatively as combined life extension and SO_2/NO_x control option. No costs were developed.

TABLE 2

ECONOMIC BASES USED TO DEVELOP THE COST ESTIMATES

Item	Value	
Operating labor	19.7	\$/person-hour
Water	0.60	\$/1000 gallons
Lime	65	\$/ton
Limestone	15	\$/ton
Land	6,500	\$/acre
Waste disposal	9.25	\$/ton
Electric power	0.05	\$/kWh
Catalyst cost	20,290	\$/ton
1988 constant dollar factors		
Operating and maintenance	1.0	
Capital carrying charges[a]	0.105	

[a]Book life - 30 years; Tax life - 20 years; Depreciation Method - Straight Line; and Discount Rate - 6.1%.

TABLE 3. RETROFIT FACTORS AFFECTING COST/PERFORMANCE

Control Technology	Access and Congestion	Ducting Distance	Additional Particulate Control	Boiler Type
Lime/Limestone Flue Gas Desulfurization	X	X		
Lime Spray Drying	X	X	X	
Coal Switching			X	X
Furnace Sorbent Injection			X	
Duct Spray Drying		X	X	
Low NO_x Combustion				X
Natural Gas Reburning				X
Selective Catalytic Reduction	X	X		X

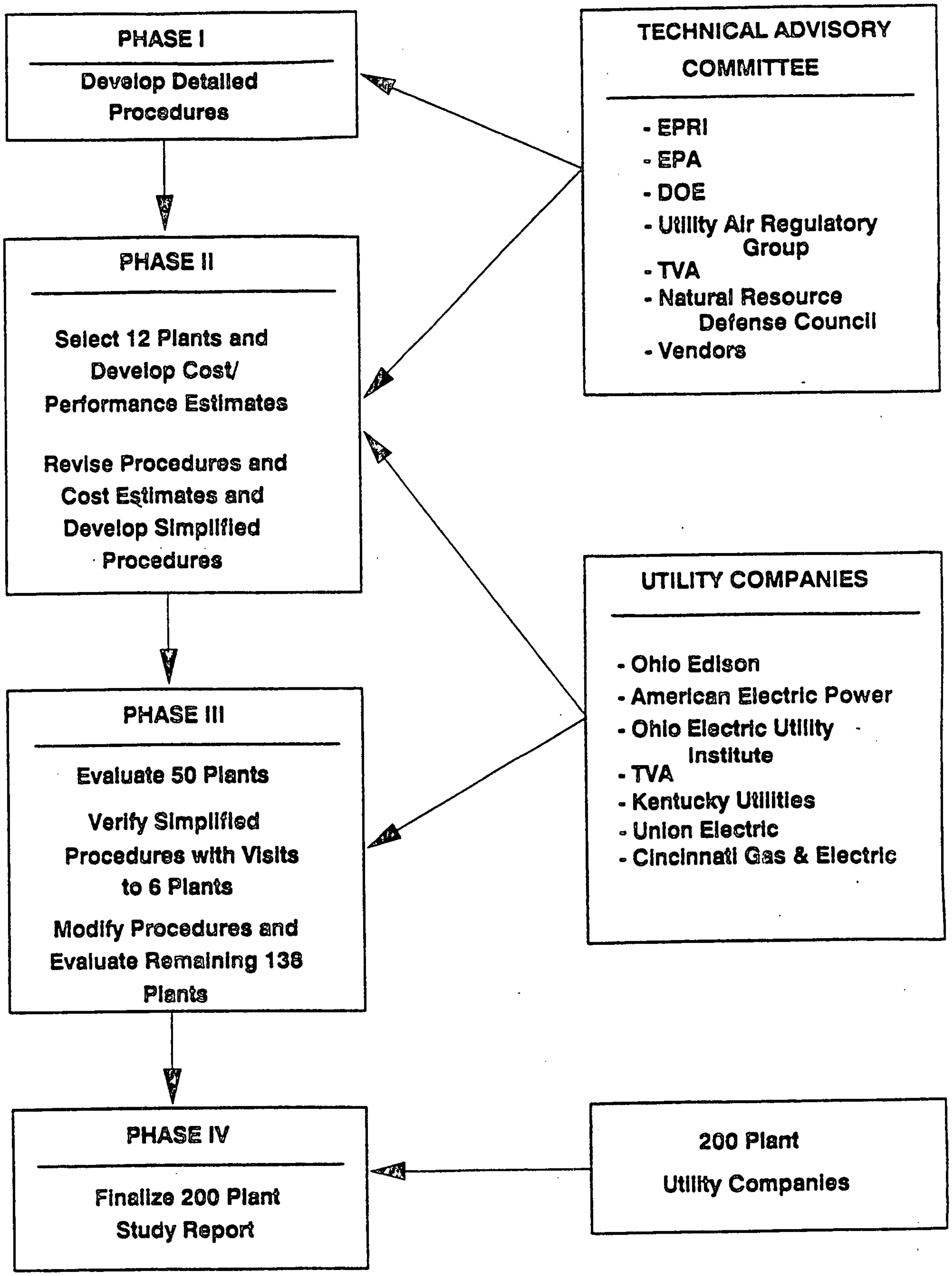

Figure 1. 200 Plant study technical approach.

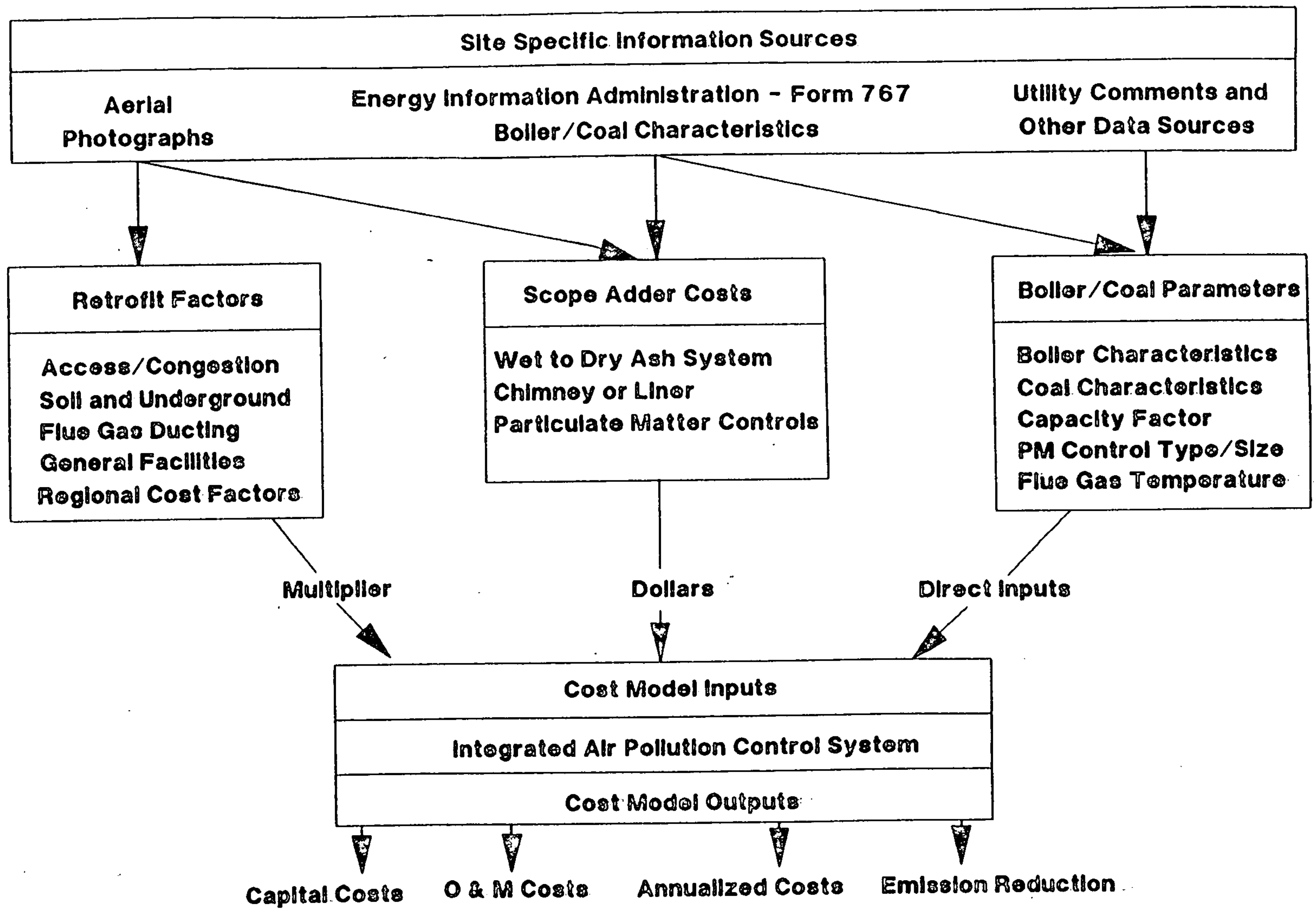

Figure 2. Site-specific cost estimation methodology.

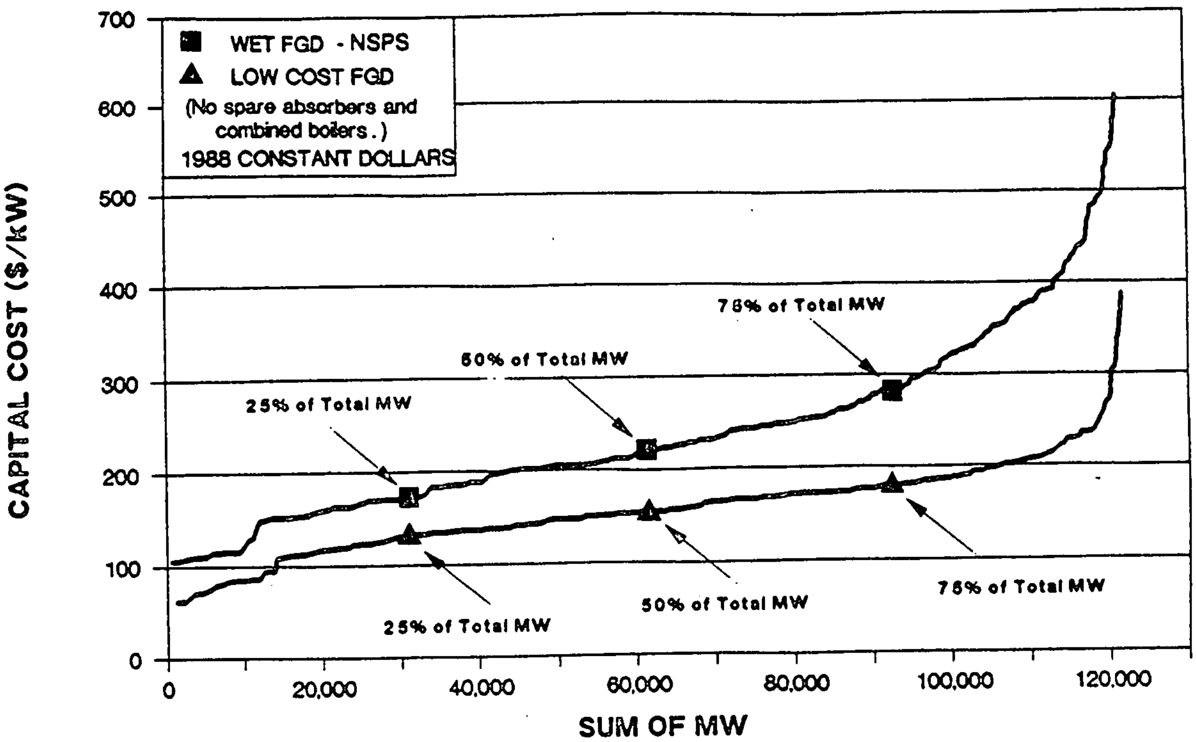

Figure 3. Summary of capital cost results for lime/limestone flue gas desulfurization.

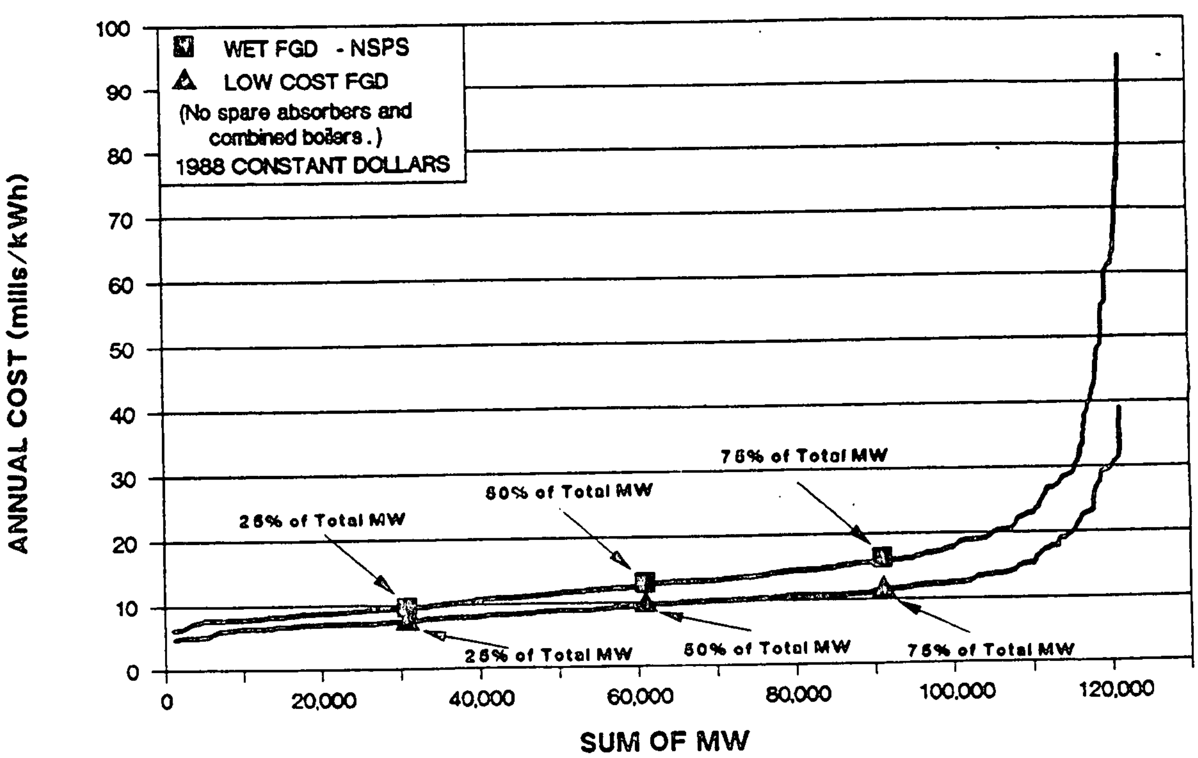

Figure 4. Summary of annual cost results for lime/limestone flue gas desulfurization.

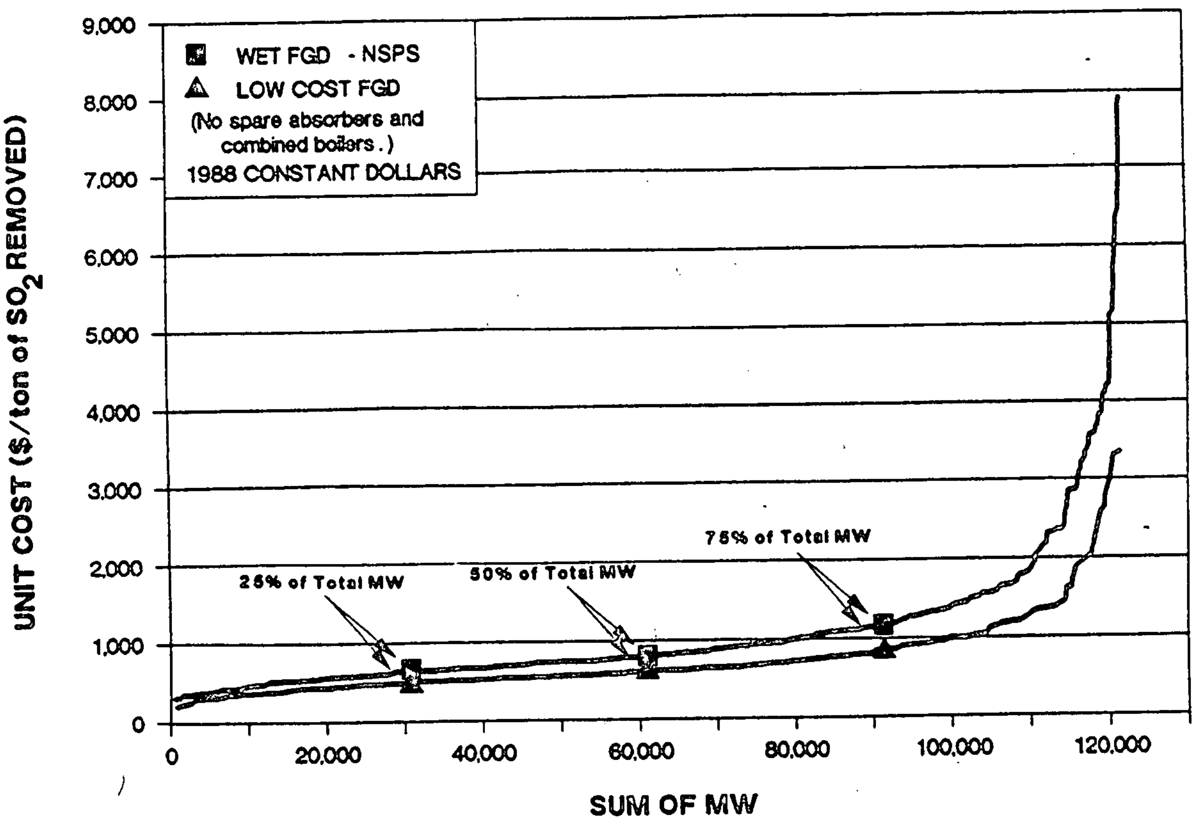

Figure 5. Summary of cost per ton of SO_2 removed results for lime/limestone flue gas desulfurization.

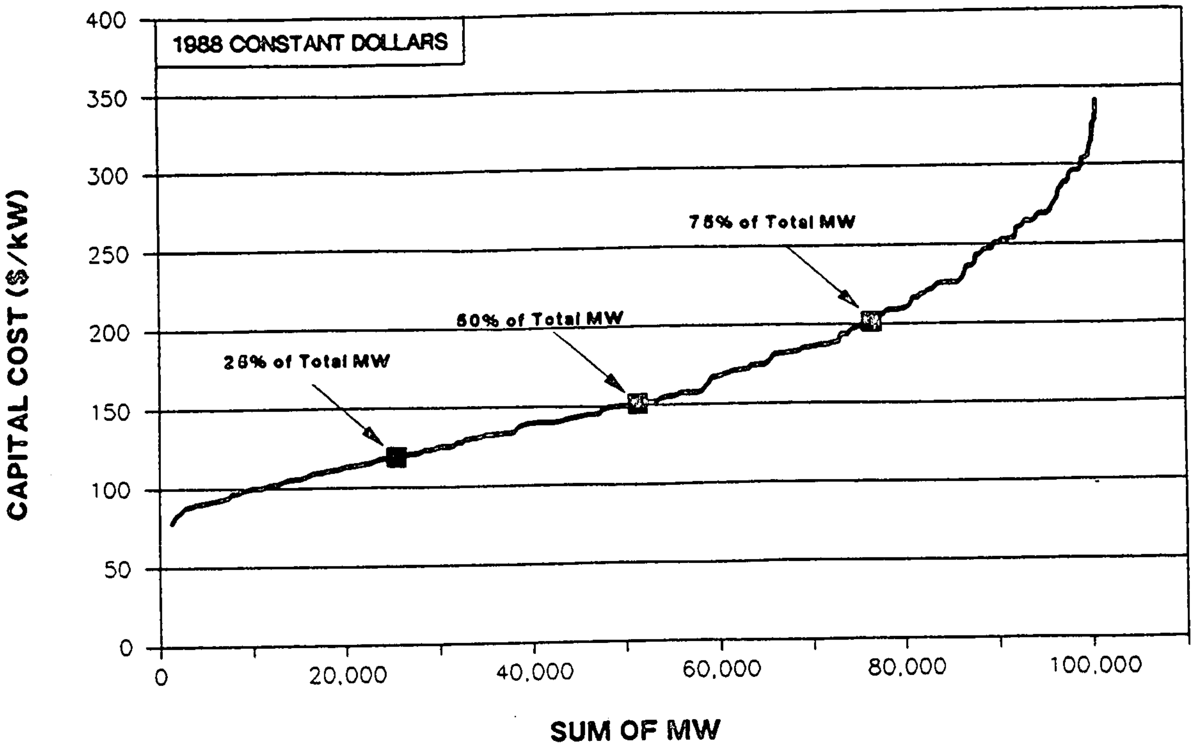

Figure 6. Summary of capital cost results for lime spray drying.

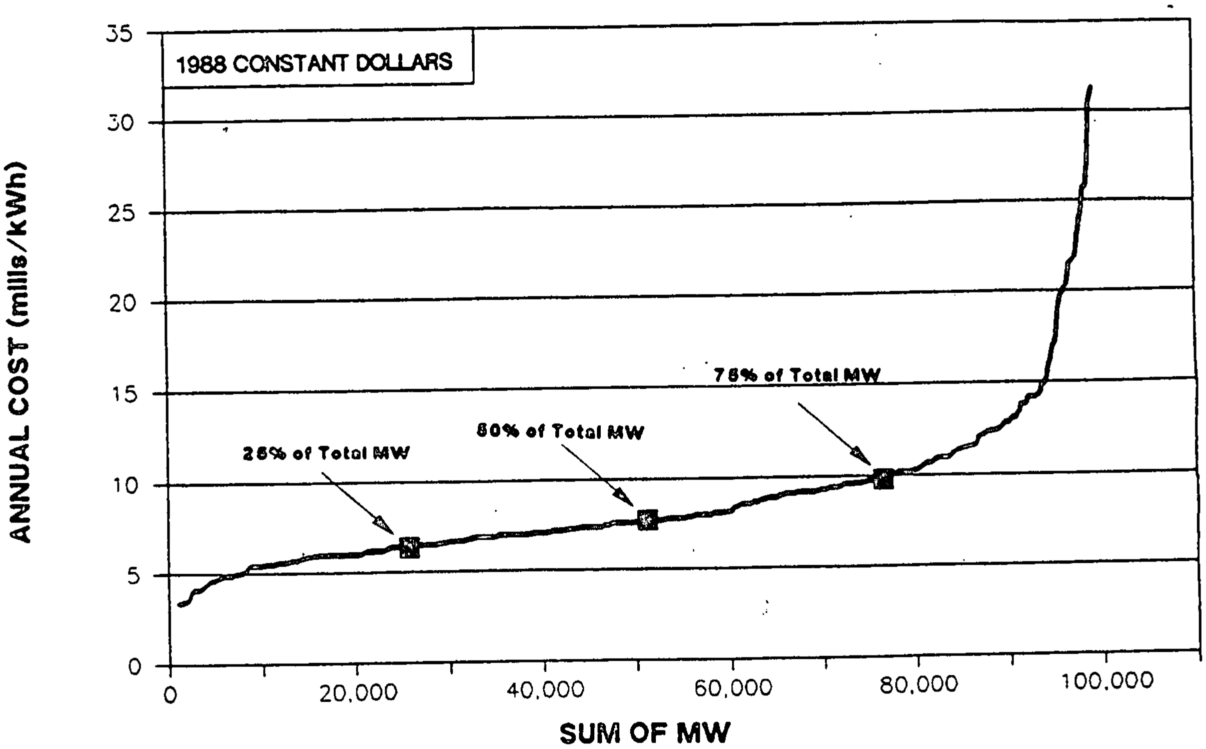

Figure 7. Summary of annual cost results for lime spray drying.

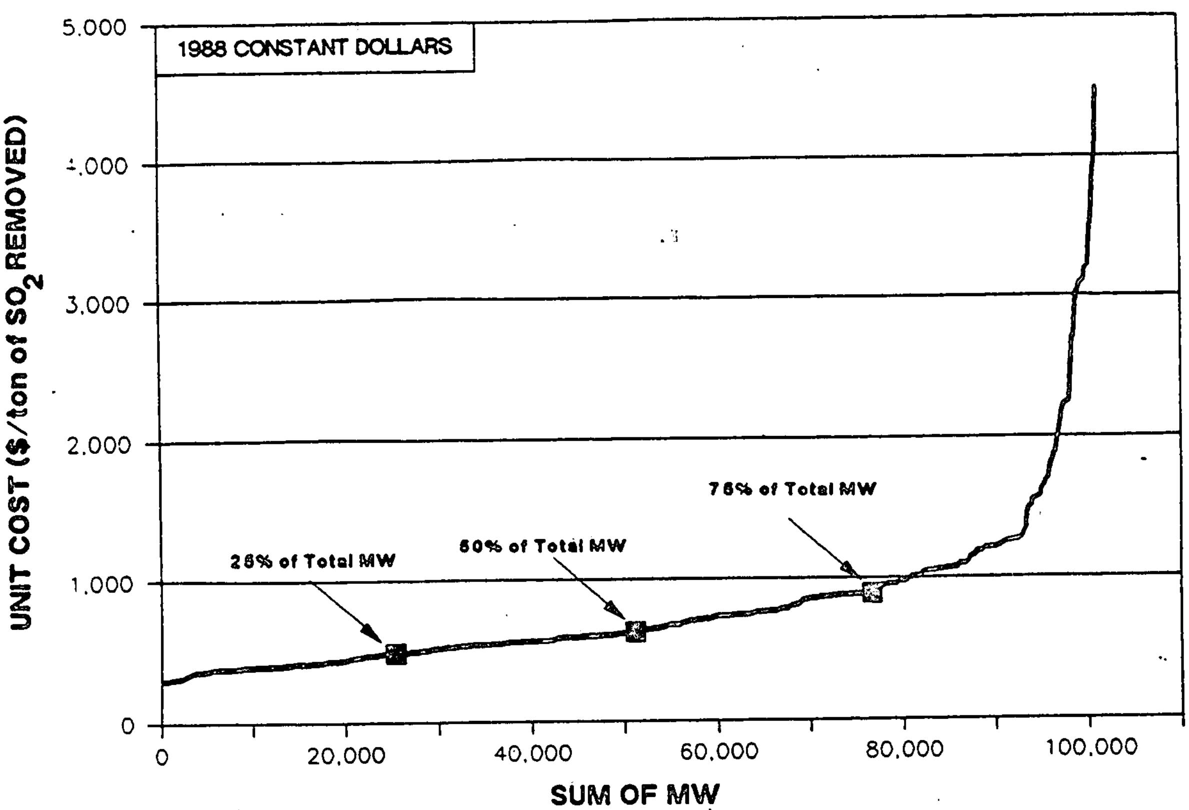

Figure 8. Summary of cost per ton of SO_2 removed results for lime spray drying.

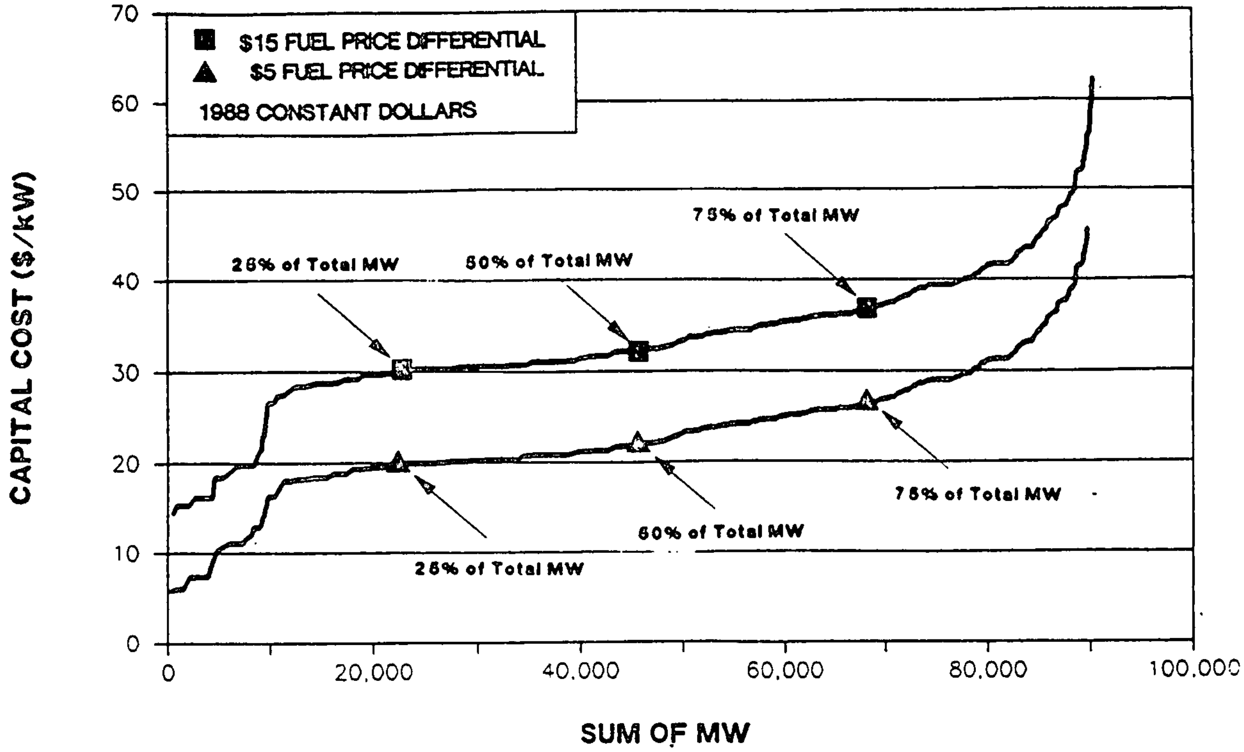

Figure 9. Summary of capital cost results for coal switching.

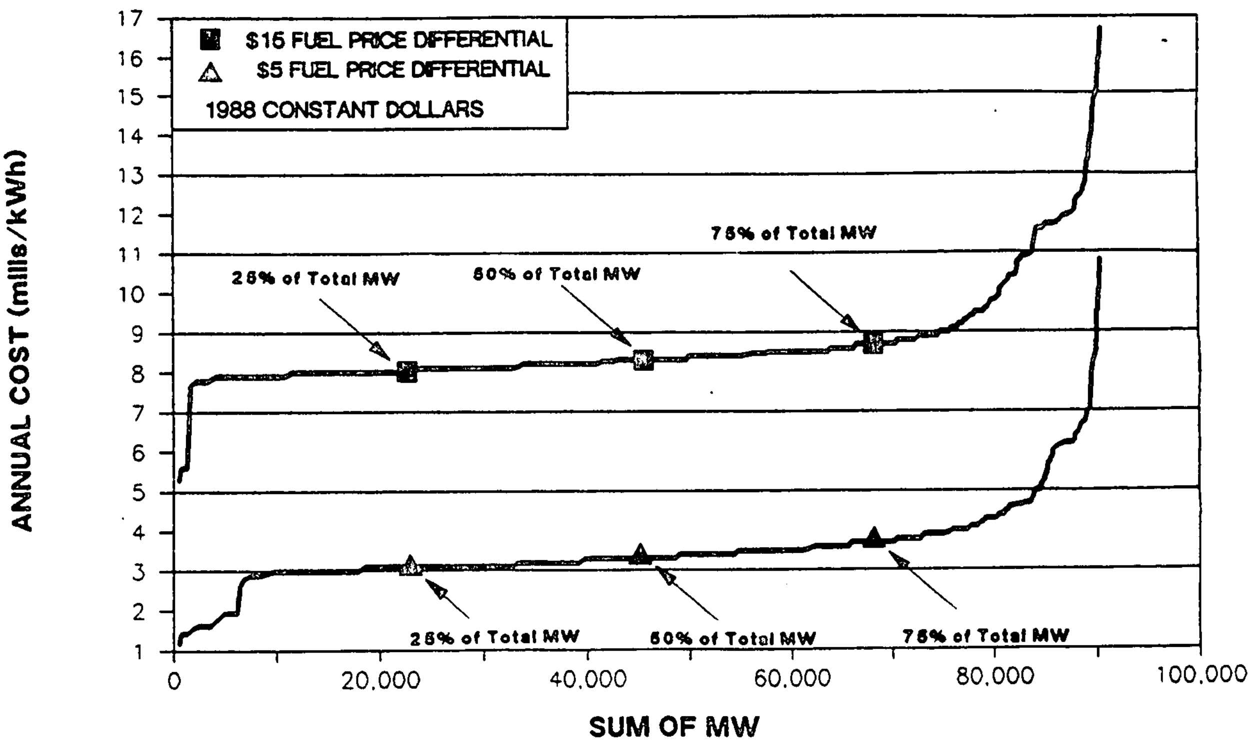

Figure 10. Summary of annual cost results for coal switching.

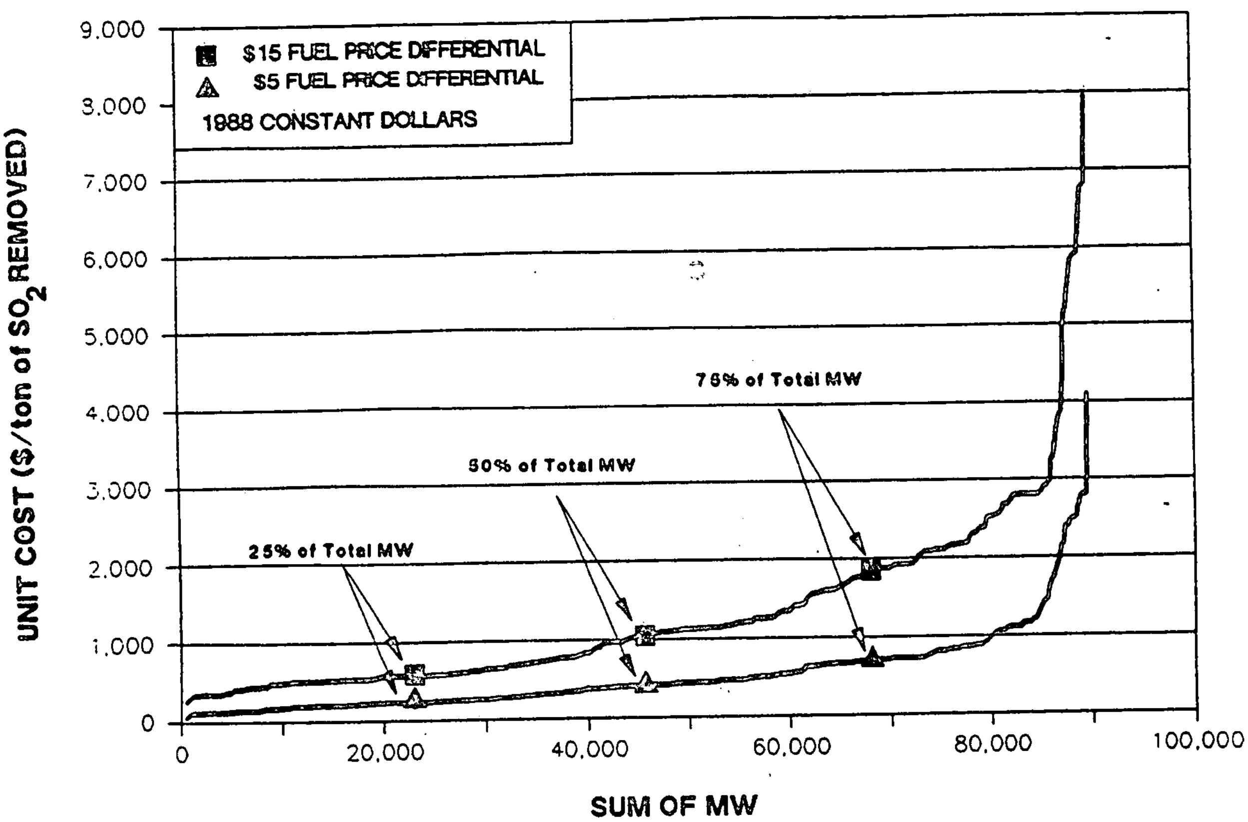

Figure 11. Summary of cost per ton of SO_2 removed results for coal switching.

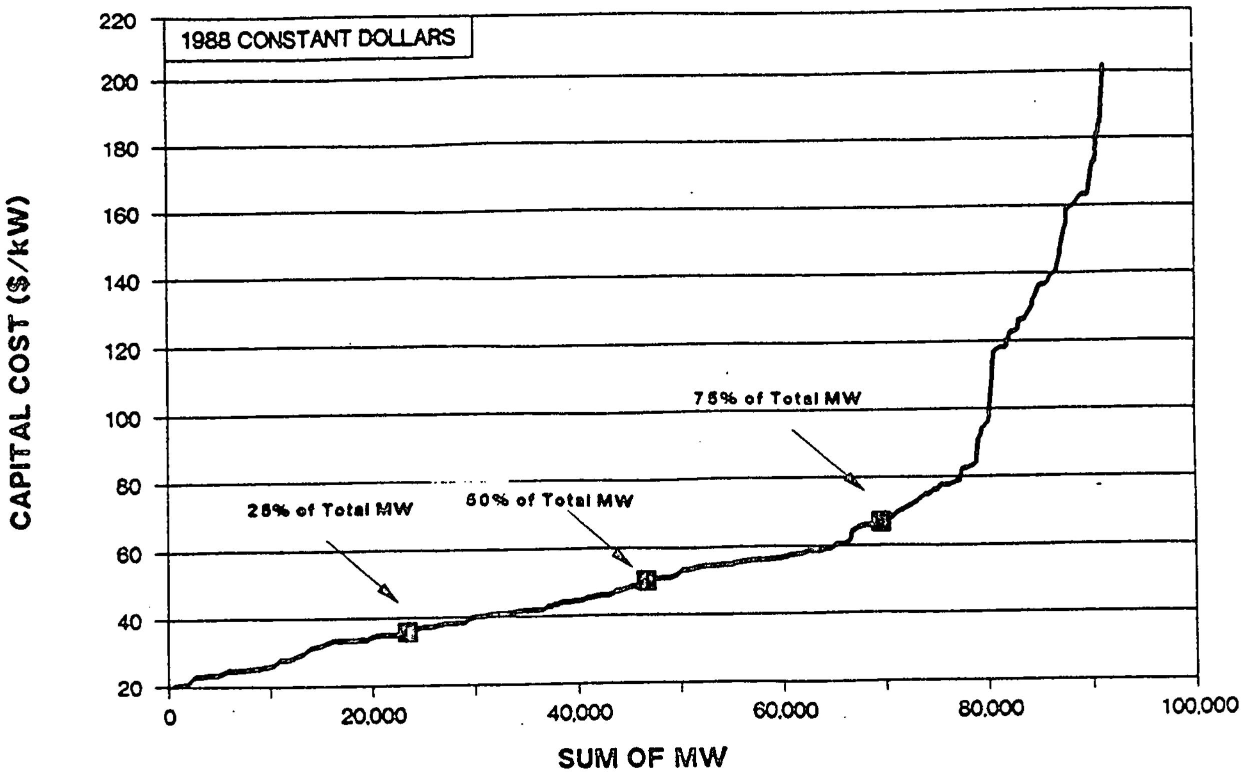

Figure 12. Summary of capital cost results for duct spray drying.

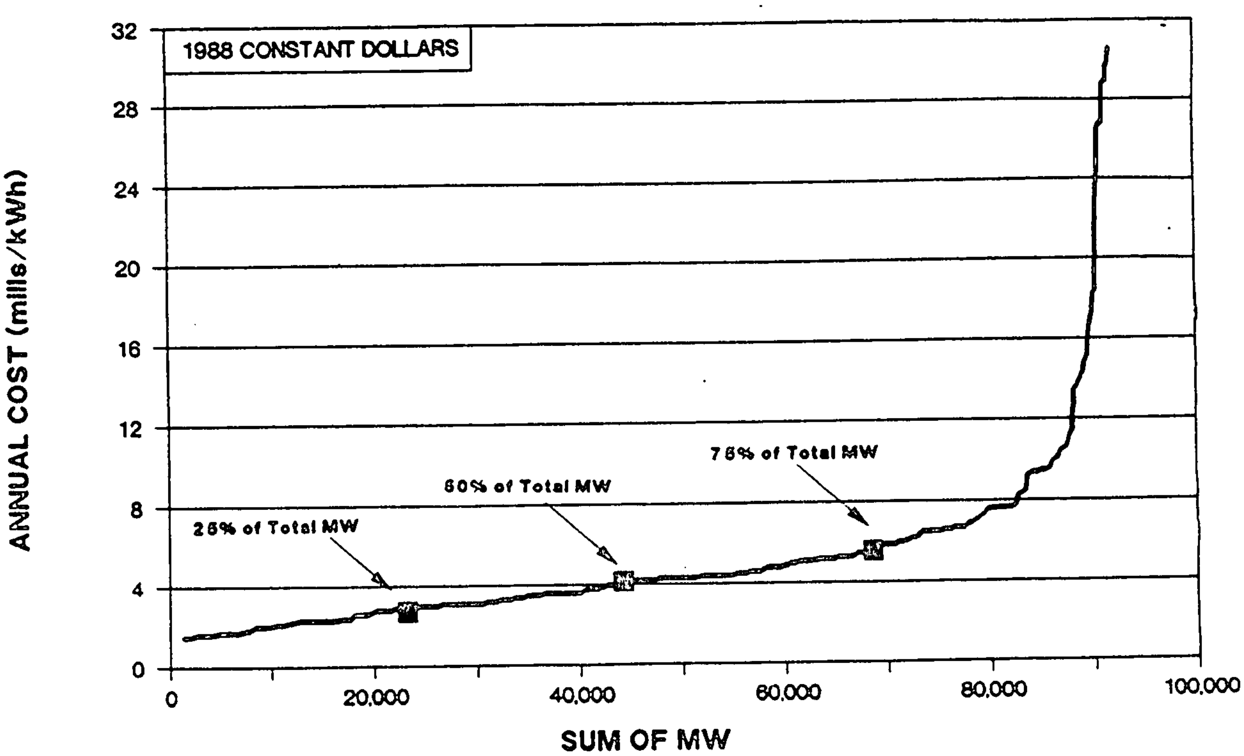

Figure 13. Summary of annual cost results for duct spray drying.

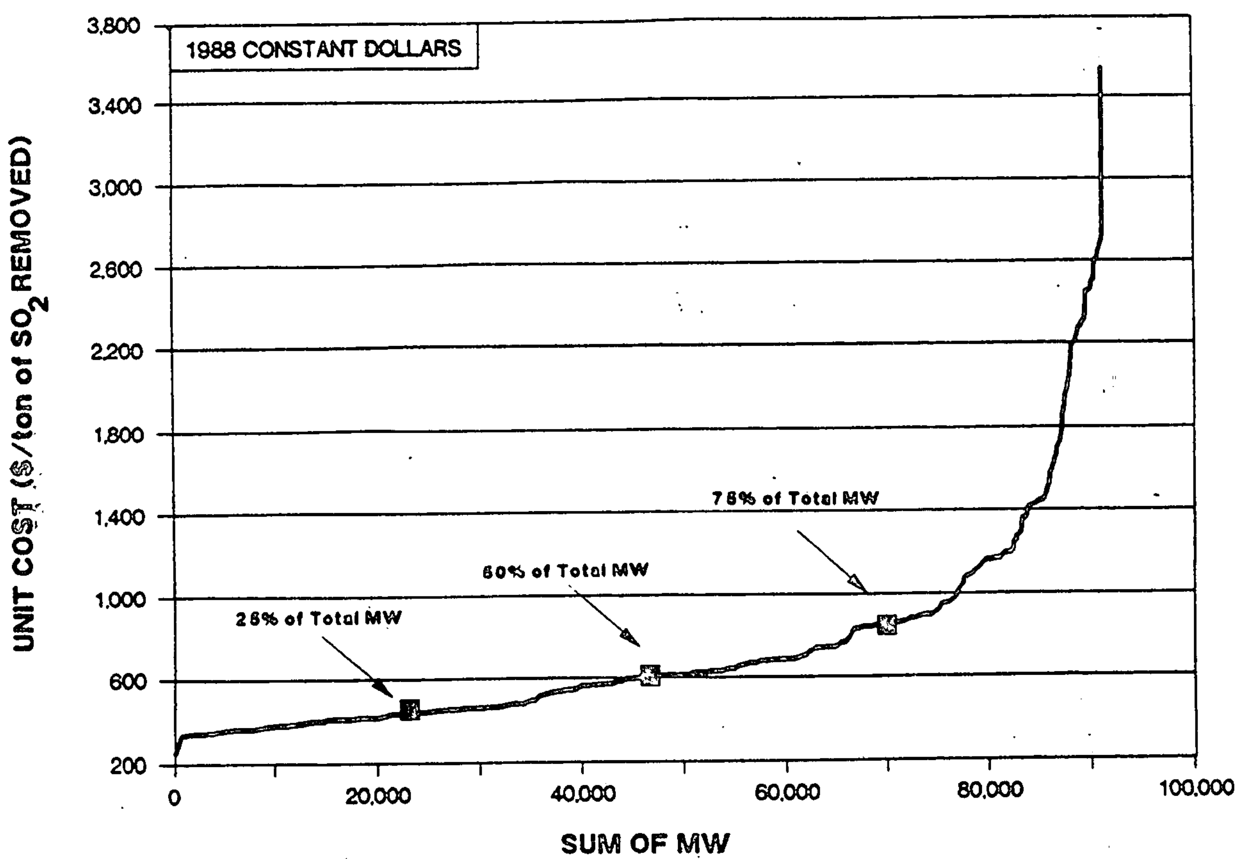

Figure 14. Summary of cost per ton of SO_2 removed results for duct spray drying.

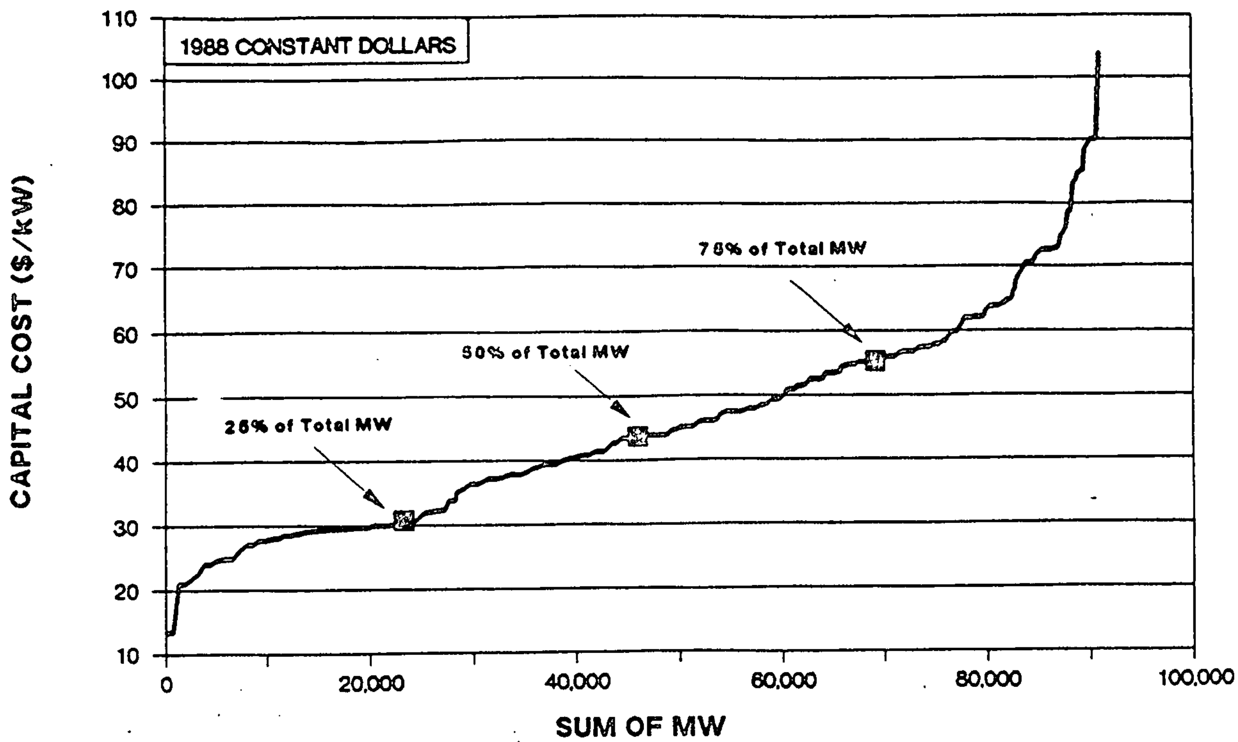

Figure 15. Summary of capital cost results for furnace sorbent injection.

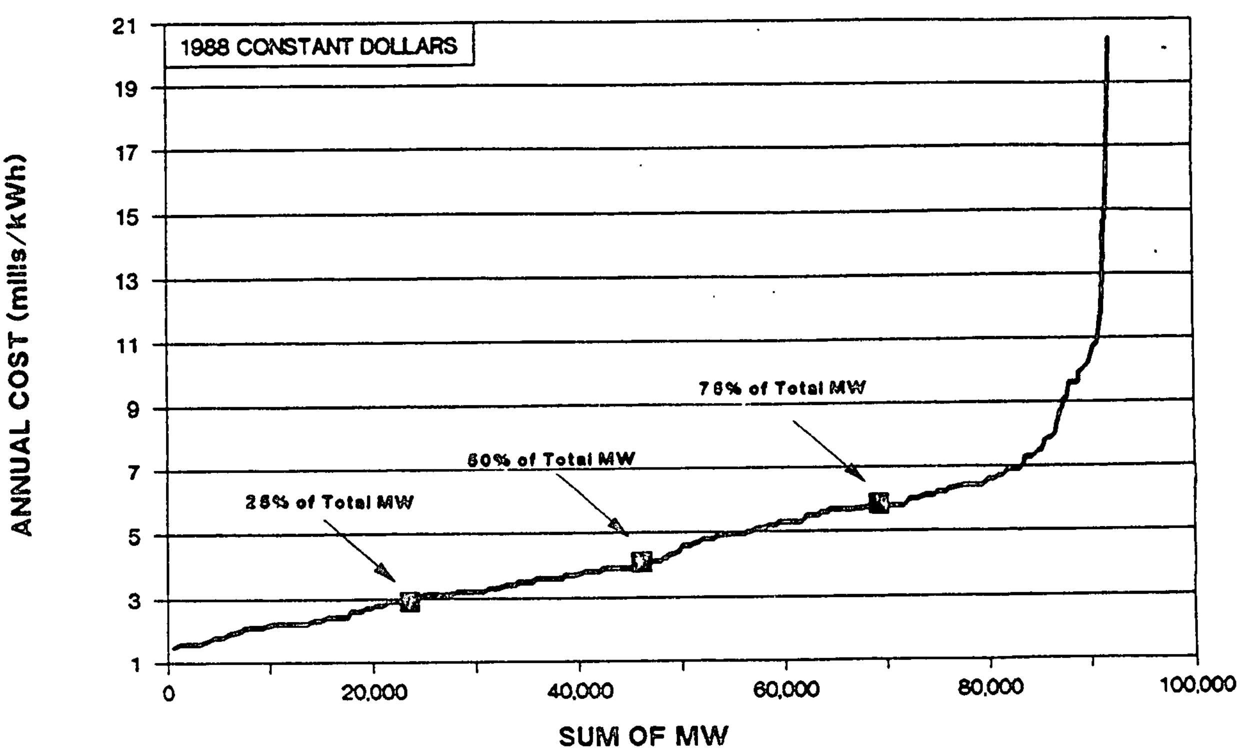

Figure 16. Summary of annual cost results for furnace sorbent injection.

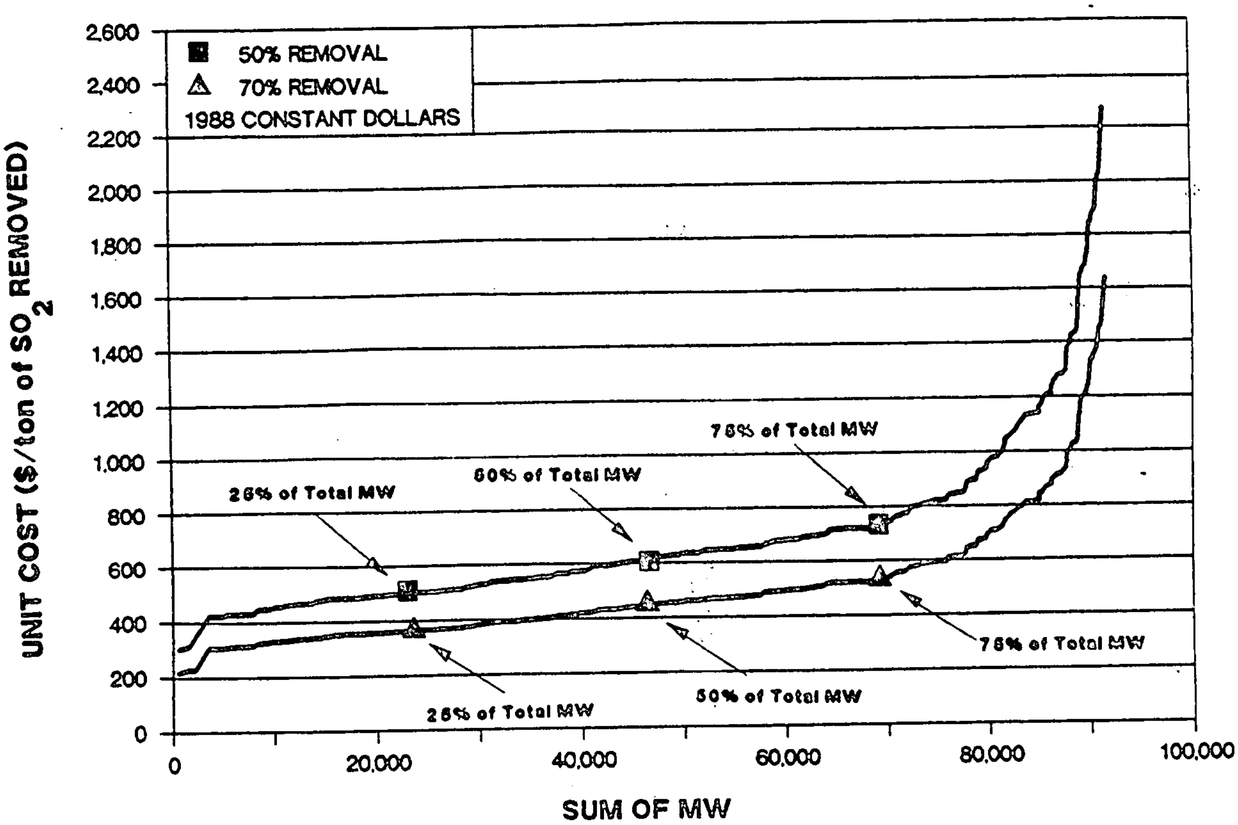

Figure 17. Summary of cost per ton of SO_2 removed results for furnace sorbent injection.

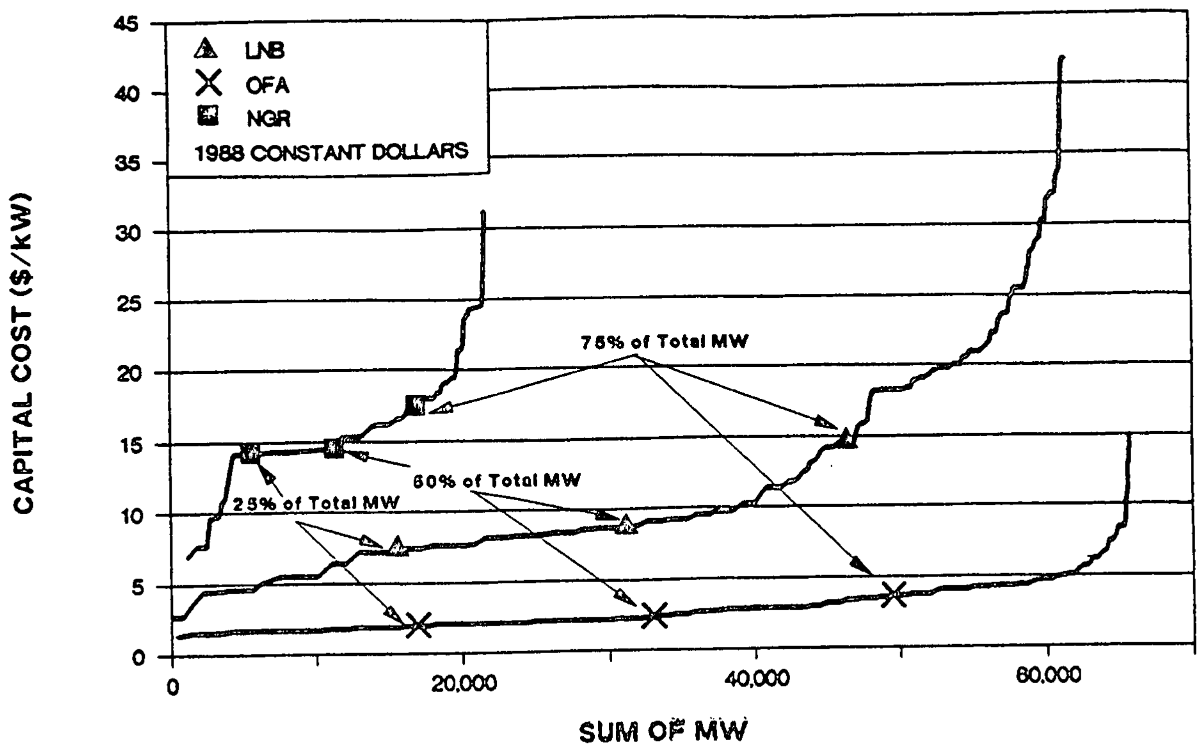

Figure 18. Summary of capital cost results for low NO_x combustion.

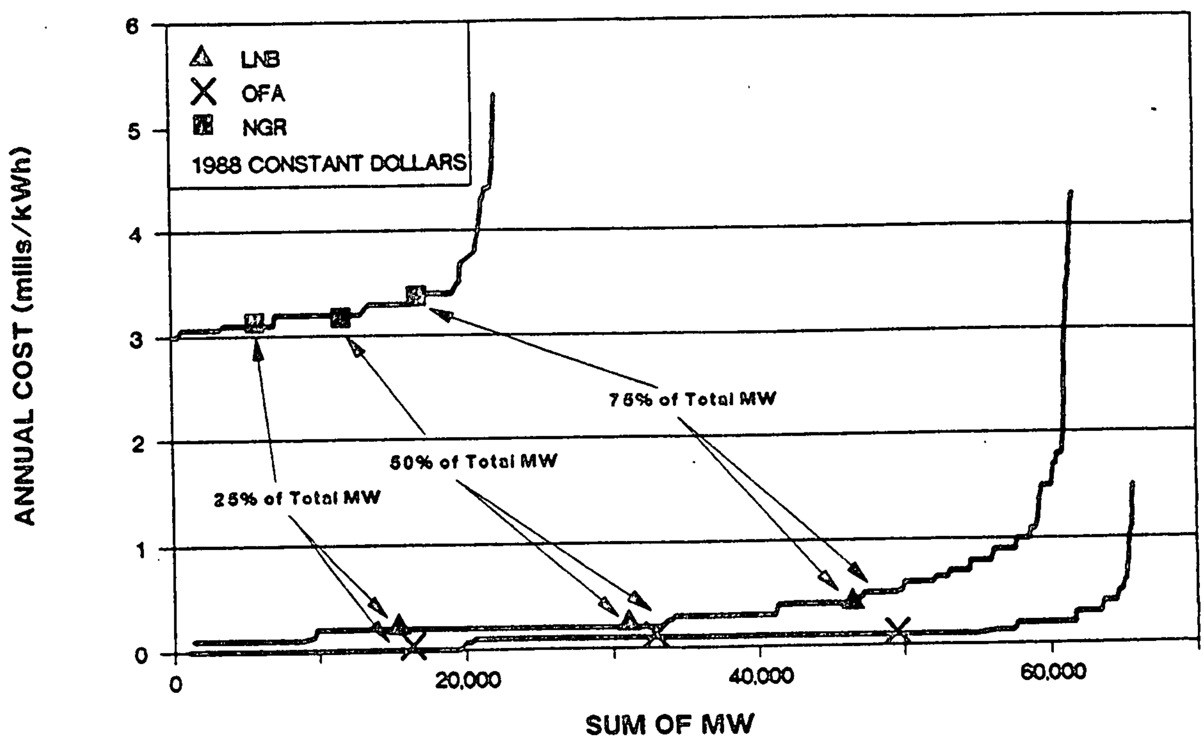

Figure 19. Summary of annual cost results for low NO_x combustion.

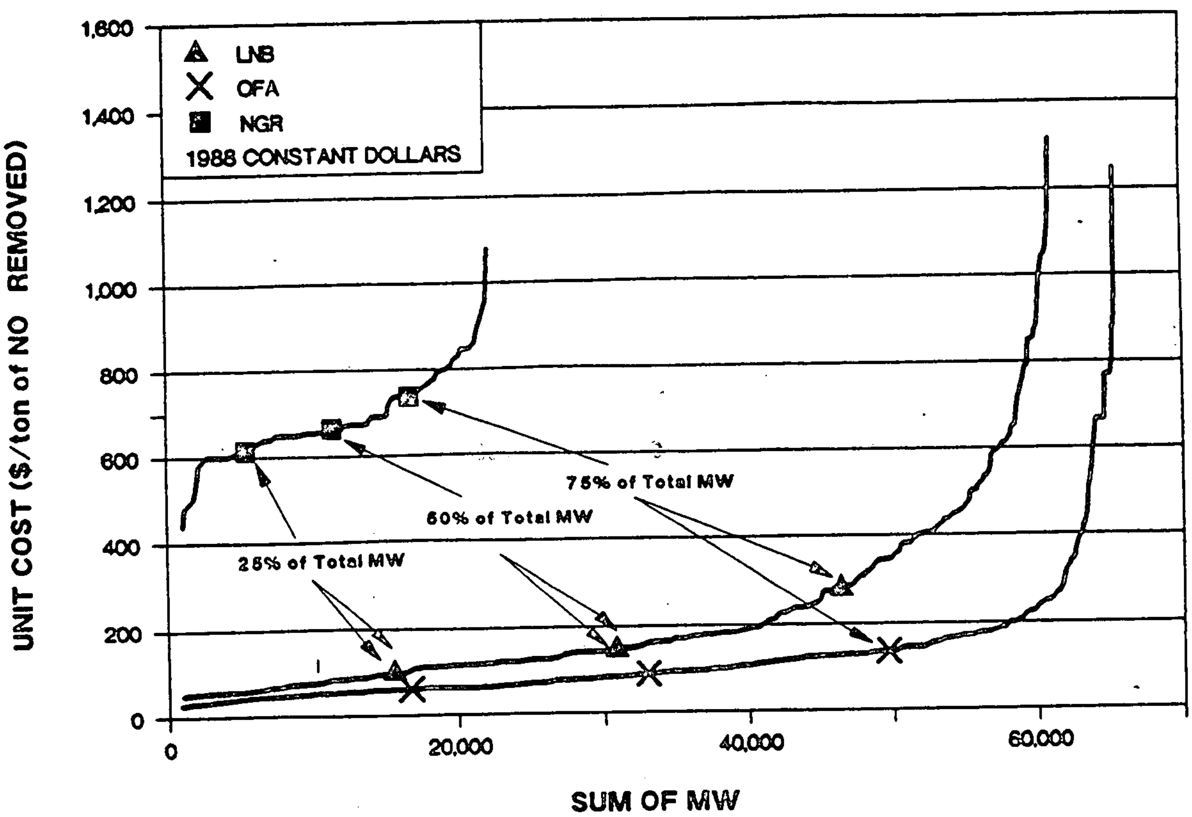

Figure 20. Summary of cost per ton of NO_x removed results for low NO_x combustion.

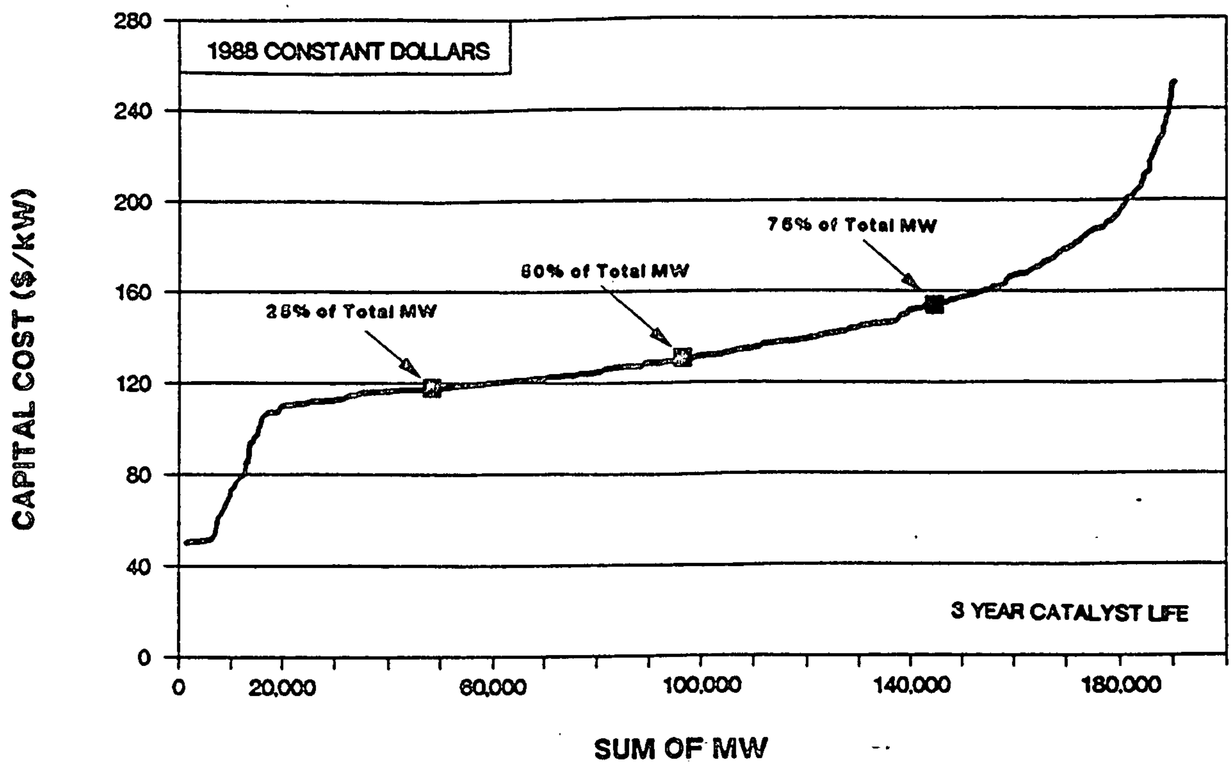

Figure 21. Summary of capital cost results for selective catalytic reduction.

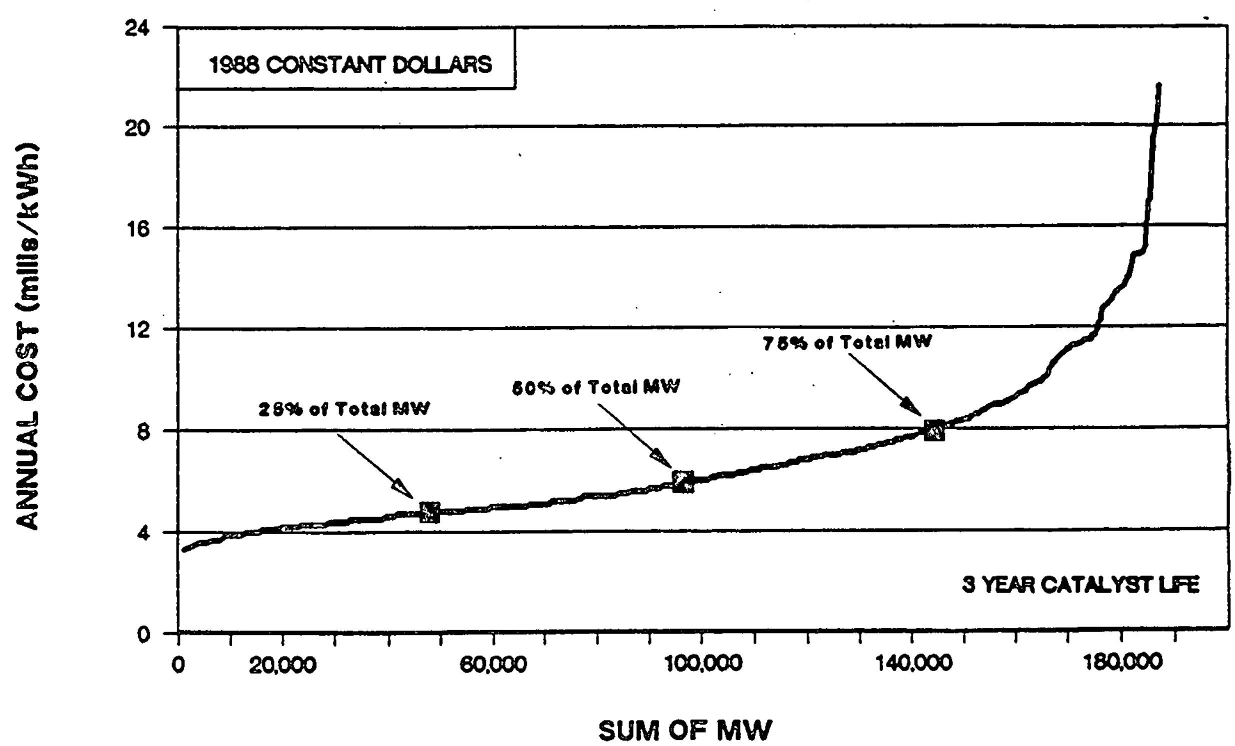

Figure 22. Summary of annual cost results for selective catalytic reduction.

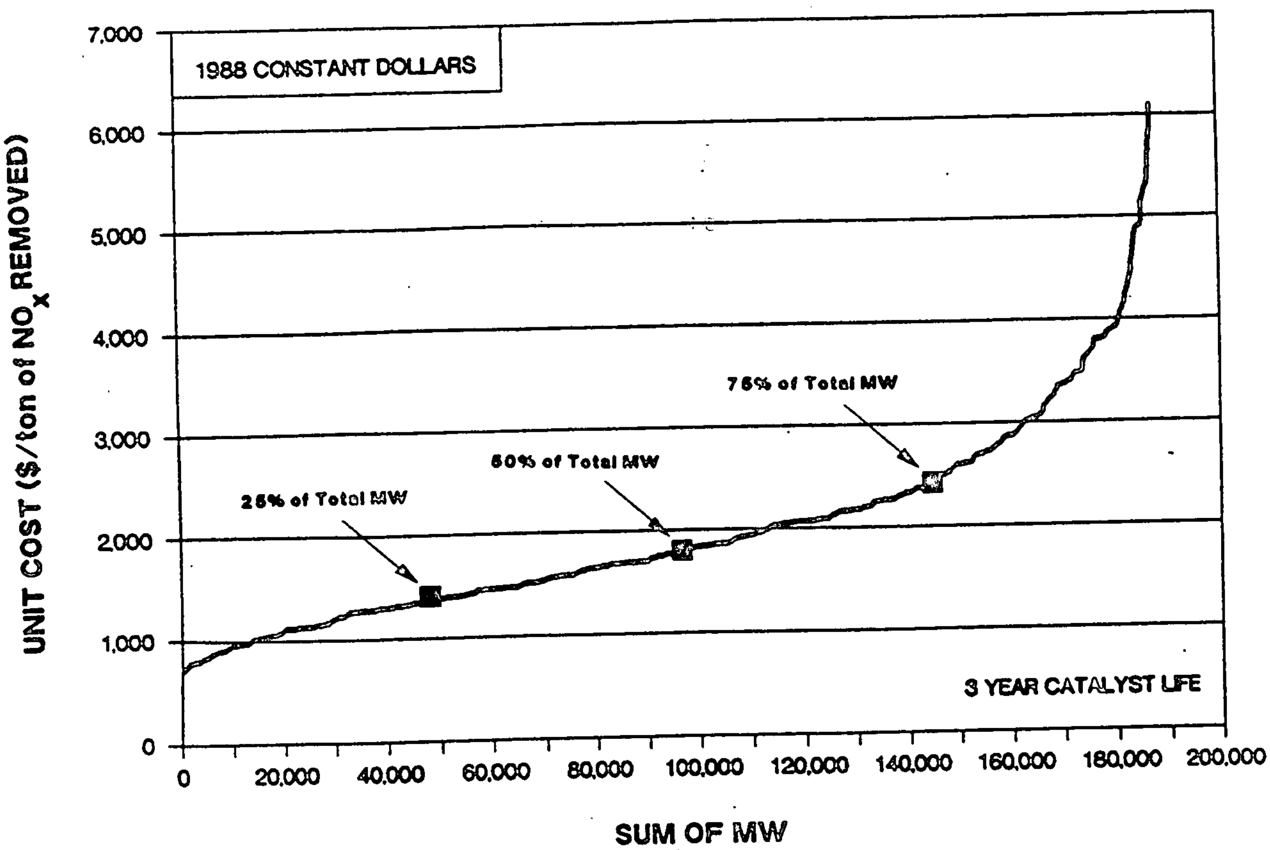

Figure 23. Summary of cost per ton of NO_x removed results for selective catalytic reduction.