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An Analysis of Costs And Cost Effectiveness Of SO_2 Control For Mixed-Fuel-Fired Steam Generating Units

NSPS

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An Analysis of Costs and Cost Effectiveness of SO_2 Control for Mixed-Fuel-Fired Steam Generating Units

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1.0 INTRODUCTION

The analysis described herein was undertaken in conjunction with efforts to develop new source performance standards (NSPS) for industrial-commercial-institutional steam generating units with heat input capacities greater than 100 million Btu/hour. Industrial-commercial-institutional steam generating units classified as mixed fuel-fired steam generating units include any unit firing a mixture of nonsulfur-bearing fuels (e.g., wood, solid waste, municipal refuse, natural gas, etc.) with sulfur-bearing fossil fuels (e.g., coal, oil).

Mixed fuel-fired steam generating units are economically attractive in many cases because the nonsulfur-bearing fuel is generally a nonfossil fuel which is replacing a more costly fossil fuel. Such units maintain the flexibility to fire 100 percent capacity of either fuel should the need arise.

Although mixed fuel-fired steam generating units may be found at a wide variety of industrial-commercial-institutional sites, the principal users of mixed fuel-fired steam generating units are industries that have a low sulfur gaseous fuel or a nonfossil fuel available on site as a byproduct of the plant's processes. By using the waste products from their processes as fuel, these industries are reducing their waste disposal costs.

Many mixed fuel combinations exist. The most common fuel combinations fired in mixed fuel-fired steam generating units are wood/coal and municipal waste/coal mixtures. Hence, the major users of mixed fuel-fired steam generating units are the forest products and the paper and allied products industries.

The objective of this report is to estimate the potential national impacts associated with possible NSPS limiting sulfur dioxide (SO_2) emissions from new, modified, or reconstructed mixed fuel-fired steam generating units. These impacts are based on an examination of the annual SO_2 control costs, SO_2 emissions, and the cost effectiveness of SO_2 control on model mixed fuel-fired steam generating units. In addition, the cost effectiveness of including versus not including an "emission credit" in possible NSPS for mixed fuel-fired steam generating units is also examined.

Projections of the number of new mixed fuel-fired steam generating units and the development of model steam generating units are discussed in Section 2.0. Section 3.0 presents the results of the model mixed fuel-fired steam generating unit cost analysis. The results of the national impacts analysis are presented in Section 4.0. Section 5.0 discusses the consideration of emission credits for mixed fuel-fired steam generating units.

2.0 PROJECTIONS OF NEW MIXED FUEL-FIRED STEAM GENERATING UNITS

A wide variety of nonsulfur-bearing fuels may be co-fired with sulfur-bearing fossil fuels in mixed fuel-fired industrial-commercial-institutional steam generating units. Little data or information are readily available, however, concerning the existing population of mixed fuel-fired steam generating units, current fuel firing practices (i.e., relative amounts of nonsulfur-bearing fuels and sulfur-bearing fossil fuels typically co-fired), or the projected growth in the number of new mixed fuel-fired steam generating units. From the data and information that are available, it appears that the major users of mixed fuel-fired steam generating units are the forest products and paper industries. Wood is the predominant nonsulfur-bearing fuel fired in these steam generating units. The growth of mixed fuel-fired steam generating units firing nonsulfur-bearing fuels other than wood is also expected to be small in comparison to wood/fossil fuel-fired steam generating units. Therefore, although the results discussed in this report are based on projections for new steam generating units firing mixtures of sulfur-bearing fossil fuels and wood, these results are considered representative of the impacts on all new mixed fuel-fired steam generating units.

Model mixed fuel-fired steam generating units were developed based on information obtained from a survey of the pulp and paper and forest products industries by the National Council of the Paper Industry for Air and Stream Improvement (NCASI).[1] This report provided information on the fuel mix, population projections, and size distribution of mixed fuel-fired steam generating units.[2]

During the five-year period from 1980 through 1984, 35 mixed fuel-fired steam generating units having a total heat input capacity of 20.1 billion Btu/hour were installed in the pulp and paper industry.[2] It is anticipated that about the same number of new mixed fuel-fired steam generating units having the same total capacity will be built over the five-year period ending in 1990. Consequently, the information provided by NCASI was used to project the population of new mixed fuel-fired steam generating units anticipated in the time frame of 1985 through 1990.

Table 1 presents the size distribution of these projected mixed fuel-fired steam generating units. Three model steam generating units were selected to represent the size range presented in Table 1. The small mixed fuel-fired steam generating units (100-250 million Btu/hour) are represented by a 150 million Btu/hour model unit, the medium sized units (250-500 million Btu/hour) are represented by a 400 million Btu/hour model unit, and large units (>500 million Btu/hour) are represented by an 800 million Btu/hour model unit.

Table 2 presents the projected fuel mix distribution of mixed fuel-fired steam generating units.[1] Three model fuel mixtures were selected to represent those presented in Table 2. Fuel mixtures of 20 percent nonsulfur-bearing fuel/80 percent sulfur-bearing fossil fuel, 50 percent nonsulfur-bearing fuel/50 percent sulfur-bearing fossil fuel, and 80 percent nonsulfur-bearing fuel/20 percent sulfur-bearing fossil fuel were chosen to represent mixed fuel steam generating units firing 0 to 49 percent nonsulfur-bearing fuel, 50 to 75 percent nonsulfur-bearing fuel, and greater than 75 percent nonsulfur-bearing fuel, respectively.

Table 2 shows that all five 150 million Btu/hour mixed fuel-fired steam generating units fire a fuel mixture near 80 percent nonsulfur-bearing fuel/20 percent sulfur-bearing fossil fuel. Table 2 also shows that 11 of the projected medium sized mixed fuel-fired steam generating units will burn a 20 percent sulfur-bearing fossil fuel mixture, 2 units will fire a 50 percent sulfur-bearing fossil fuel mixture, and 2 units will fire an 80 percent sulfur-bearing fossil fuel mixture. Of the large mixed fuel-fired steam generating units, four units will fire 20 percent sulfur-bearing fossil fuel, two units will fire 50 percent sulfur-bearing fossil fuel, and nine units will fire 80 percent sulfur-bearing fossil fuel.

Regions I, IV, and X were selected for analysis of the potential impacts of SO_2 control on new mixed fuel-fired steam generating units. These three regions were selected because they have a high concentration of pulp and paper and forest product industries.[3] Thus, most new mixed

TABLE 1. PROJECTED SIZE DISTRIBUTION OF NEW MIXED FUEL-FIRED STEAM GENERATING UNITS FOR THE PERIOD 1985 TO 1990

Heat Input Capacity (million Btu/hr)	Model Unit Size (million Btu/hr)	Number of Units
100 - 250	150	5
250 - 500	400	15
>500	800	15

TABLE 2. POPULATION PROJECTIONS OF NEW MODEL MIXED FUEL-FIRED STEAM GENERATING UNITS FOR THE PERIOD 1985 TO 1990 (NUMBER OF UNITS)

Model Unit Size (million Btu/hr)	Fuel Mix		
	20% Fossil/80% Nonfossil	50% Fossil/50% Nonfossil	80% Fossil/20% Nonfossil
150	5	-	-
400	11	2	2
800	4	2	9

fuel-fired steam generating units are expected to be installed in these regions. Based on historical data, 23 percent of mixed fuel-fired steam generating units in the paper and allied products industry are in Region I, 45 percent of the units are in Region IV, and 32 percent of the units are in Region X.[3] It is assumed that new mixed fuel-fired units will follow this same regional distribution. Within each region, mixed fuel-fired steam generating units are distributed according to size and fuel mixture as discussed above. On this basis, Table 3 presents the regional distribution of the projected model mixed fuel-fired steam generating units.

TABLE 3. REGIONAL DISTRIBUTION OF MODEL MIXED FUEL-FIRED STEAM GENERATING UNITS
(NUMBER OF UNITS)

Model Unit Size (million Btu/hr)	Region I			Region IV			Region X		
	20% Fossil Fuel	50% Fossil Fuel	80% Fossil Fuel	20% Fossil Fuel	50% Fossil Fuel	80% Fossil Fuel	20% Fossil Fuel	50% Fossil Fuel	80% Fossil Fuel
150	1	0	0	2	0	0	2	0	0
400	2	0	0	5	1	1	4	1	1
800	1	0	2	2	1	4	1	1	3

3.0 MIXED FUEL-FIRED STEAM GENERATING UNIT SO_2 CONTROL COST

This section presents the results of an analysis of SO_2 control costs for mixed fuel-fired steam generating units. This analysis considers two alternative control levels:

(1) The use of low sulfur fuels containing less than 1.2 lb SO_2/million Btu for coal and less than 0.8 lb SO_2/million Btu for oil.

(2) The use of flue gas desulfurization (FGD) systems to achieve a 90 percent reduction in SO_2 emissions.

All costs presented in this analysis are in January 1983 dollars. Appendix A summarizes the general procedure and major assumptions used to develop the cost estimates. The analysis is consistent with that contained in the Industrial Boiler SO_2 Cost Report.[4] The regulatory baseline is the same (i.e., existing State implementation plans [SIP's]) and, as in the Industrial Boiler SO_2 Cost Report, the costs of sodium FGD systems have been used to represent the costs of FGD systems in general.[4] For the 800 million Btu/hour units, the FGD cost is represented by two shop fabricated 400 million Btu/hour units. Sodium FGD systems larger than about 400 million Btu/hour are not available on a "packaged" basis. Because it costs less to install two packaged FGD systems and increase overall reliability, two 400 million Btu/hour packaged FGD units were selected over a field erected 800 million Btu/hour FGD unit.

This analysis also assumes an overall annual capacity factor of 0.6. As discussed in the Industrial Boiler SO_2 Cost Report, this annual capacity factor is considered representative of industrial-commercial-institutional steam generating units in general.

Fossil fuel prices (Table 4) have also been assumed to be the same as those used in the Industrial Boiler SO_2 Cost Report. Data are generally unavailable, however, on the cost of nonfossil fuel. In some cases the nonfossil fuel may be a byproduct of the plant's processes that could not be

TABLE 4. REGIONAL FUEL PRICES IN \$/MILLION BTU (JANUARY 1983 \$)[a,b,c]

Fuel Type	Sulfur Content ($lb\ SO_2/10^6$ Btu)[d]	REGION I	II	III	IV	V	VI	VII	VIII	IX	X
COAL											
Bituminous											
B	0.95	3.76	3.52	3.14	3.19	3.32	3.34	3.14	1.99	2.80	3.18
D	1.45	3.71	3.45	2.94	2.98	3.18	3.21	3.08	1.86	2.82	2.97
E	2.10	3.65	3.30	2.85	2.96	3.08	3.20	3.04	1.87	2.77	2.84
F	2.85	3.46	3.13	2.75	2.88	2.93	3.19	2.92	N/A[f]	N/A	N/A
G	4.15	3.16	2.82	2.42	2.80	2.67	3.09	2.62	N/A	N/A	N/A
H	5.54	3.26	2.85	2.39	2.62	2.50	2.96	2.47	N/A	N/A	N/A
Subbituminous											
B	0.95	N/A	N/A	N/A	N/A	3.38	3.49	2.74	1.40	2.84	2.66
D	1.45	N/A	N/A	N/A	N/A	3.34	3.39	2.69	1.39	2.74	2.60
E	2.10	N/A	N/A	N/A	N/A	3.30	3.32	2.72	1.28	2.65	2.09
RESIDUAL OIL 0.8 lb $SO_2/10^6$ Btu[e]	0.80	5.50	5.49	5.49	5.46	5.63	5.49	5.60	5.29	5.11	5.07
NATURAL GAS	-	5.83	5.79	5.73	6.02	5.88	5.41	5.45	4.91	5.44	5.57

[a] Reference 4.

[b] 1990 levelized fuel prices in January 1983 dollars.

[c] To convert $\$/10^6$ Btu to \$/kJ, multiply by 0.947.

[d] To convert $lb/10^6$ Btu to ng/J, multiply by 430.

[e] Subtract $\$0.70/10^6$ Btu for 3.0 lb $SO_2/10^6$ Btu oil; subtract $\$0.38/10^6$ Btu for 1.6 lb $SO_2/10^6$ Btu oil; add $\$0.37/10^6$ Btu for 0.3 lb $SO_2/10^6$ Btu oil.

[f] N/A = Not Available.

sold and which has a negligible cost associated with its use as a fuel. In other cases, however, the nonfossil fuel is purchased much as are fossil fuels. In general, there is some cost associated with the use of nonfossil fuel, although it is unlikely that the cost of nonfossil fuel would be higher than that of available coal on a heating value basis. Thus, this analysis considers two cost scenarios for nonfossil fuel: (1) nonfossil fuel has zero cost, and (2) nonfossil fuel has the same cost as the least expensive coal available (on a $/million Btu basis).

Coal/Nonfossil Mixed Fuel-Fired Steam Generating Units

Tables 5, 6, and 7 present the results of the cost analysis for coal/nonfossil mixed fuel-fired steam generating units in Regions I, IV, and X, respectively. As mentioned previously, these three regions are expected to have the majority of new installations of mixed fuel-fired steam generating units due to the high concentration of pulp and paper and forest products industries. The average cost effectiveness of SO_2 control of an alternative control level based on the use of low sulfur coal is less than $380/ton in Region I, $325/ton in Region IV, and $1,000/ton in Region X.

The average cost effectiveness of SO_2 control associated with an alternative control level based on the use of low sulfur coal is significantly higher in Region X than in Regions I and IV. This is due to the much lower emission reductions achieved between a medium and low sulfur coal in Region X compared to the SO_2 emission reductions achieved between a high and low sulfur coal in Regions I and IV.

As expected, the average cost effectiveness of SO_2 control associated with an alternative control level based on the use of low sulfur coal does not vary with the size of the mixed fuel-fired steam generating unit. As shown, however, it does vary with the proportion of coal present in the fuel mixture fired.

This results from the assumption of "emission credits" under the regulatory baseline for mixed fuel-fired steam generating units. Currently, under the existing new source performance standard for industrial-

TABLE 5. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR COAL/NONFOSSIL MIXED FUEL-FIRED STEAM GENERATING UNITS IN REGION I

Unit Size/ Control Alternative	20 Percent Coal/80 Percent Nonfossil Fuel					50 Percent Coal/50 Percent Nonfossil Fuel					80 Percent Coal/20 Percent Nonfossil Fuel				
	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Q = 150 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	G-Bit	3,671	328	-	-	G-Bit	4,562	818	-	-	F-Bit	5,619	899	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Bit	3,766	75	375	-	B-Bit	4,799	187	375	-	B-Bit	5,809	300	317	-
Percent Reduction (FGD)[e] (90% Reduction)	G-Bit	4,075	26	1,338	6,306	G-Bit	5,111	65	729	2,579	G-Bit	6,112	105	621	1,554
Q = 400 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	G-Bit	7,985	872	-	-	G-Bit	10,331	2,181	-	-	F-Bit	13,148	2,397	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Bit	8,238	200	375	-	B-Bit	10,963	499	376	-	B-Bit	13,648	799	313	-
Percent Reduction (FGD)[e] (90% Reduction)	G-Bit	8,741	70	940	3,869	G-Bit	11,447	175	556	1,494	G-Bit	14,121	279	459	910
Q = 800 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	G-Bit	13,592	1,745	-	-	G-Bit	18,218	4,362	-	-	F-Bit	23,785	4,793	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Bit	14,097	400	375	-	B-Bit	19,486	999	377	-	B-Bit	24,784	1,598	313	-
Percent Reduction (FGD)[e] (90% Reduction)	G-Bit	15,104	140	940	3,873	G-Bit	20,450	349	556	1,483	G-Bit	25,730	588	462	937

[a]Based on a capacity factor of 0.6 and zero cost for nonfossil fuel.

[b]Allowing dilution at baseline results in a 12.5 lb SO_2/million Btu limit. Since this type of coal is not available, emissions are based on the lowest cost coal available.

[c]Compared to Regulatory Baseline.

[d]Compared to less stringent alternative.

[e]The annual emissions are based on a 92% removal efficiency. The additional 2% accounts for FGD variability.

TABLE 6. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR COAL/NONFOSSIL MIXED FUEL-FIRED STEAM GENERATING UNITS IN REGION IV

Unit Size/ Control Alternative	20 Percent Coal/80 Percent Nonfossil Fuel					50 Percent Coal/50 Percent Nonfossil Fuel					80 Percent Coal/20 Percent Nonfossil Fuel				
	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Q = 150 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	H-Bit	3,587	437	-	-	G-Bit	4,419	818	-	-	F-Bit	5,251	899	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Bit	3,677	75	248	-	B-Bit	4,573	187	244	-	B-Bit	5,446	300	325	-
Percent Reduction (FGD)[e] (90% Reduction)	H-Bit	4,026	35	1,092	8,725	H-Bit	4,972	87	756	3,990	H-Bit	5,888	140	839	2,763
Q = 400 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	H-Bit	7,759	1,165	-	-	G-Bit	9,914	2,181	-	-	F-Bit	12,159	2,397	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Bit	7,999	200	249	-	B-Bit	10,325	499	244	-	B-Bit	12,678	799	325	-
Percent Reduction (FGD)[e] (90% Reduction)	H-Bit	8,601	93	785	5,626	H-Bit	11,018	233	567	2,605	H-Bit	13,541	373	682	2,026
Q = 800 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	H-Bit	13,165	2,329	-	-	G-Bit	17,459	4,362	-	-	F-Bit	21,760	4,793	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Bit	13,645	400	249	-	B-Bit	18,274	999	242	-	B-Bit	22,798	1,598	325	-
Percent Reduction (FGD)[e] (90% Reduction)	H-Bit	14,849	186	786	5,626	H-Bit	19,666	466	566	2,612	H-Bit	24,523	745	683	2,022

[a]Based on a capacity factor of 0.6 and zero cost for nonfossil fuel.

[b]Allowing dilution at baseline results in a 12.5 lb SO_2/million Btu limit. Since this type of coal is not available, emissions are based on the lowest cost coal available.

[c]Compared to Regulatory Baseline.

[d]Compared to less stringent alternative.

[e]The annual emissions are based on a 92% removal efficiency. The additional 2% accounts for FGD variability.

TABLE 7. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR COAL/NONFOSSIL MIXED FUEL-FIRED STEAM GENERATING UNITS IN REGION X

Unit Size/ Control Alternative	20 Percent Coal/80 Percent Nonfossil Fuel					50 Percent Coal/50 Percent Nonfossil Fuel					80 Percent Coal/20 Percent Nonfossil Fuel				
	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[a] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Q = 150 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	E-Sub	3,587	166	-	-	E-Sub	4,268	414	-	-	E-Sub	4,910	662	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Sub	3,677	75	989	-	B-Sub	4,495	187	1,000	-	B-Sub	5,273	300	1,003	-
Percent Reduction (FGD)[e] (90% Reduction)	E-Sub	3,944	13	2,333	4,306	E-Sub	4,713	33	1,168	1,416	E-Sub	5,445	53	878	696
Q = 400 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	E-Sub	7,658	442	-	-	E-Sub	9,374	1,104	-	-	E-Sub	11,015	1,766	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Sub	7,898	200	992	-	B-Sub	9,978	499	998	-	B-Sub	11,982	799	1,000	-
Percent Reduction (FGD)[e] (90% Reduction)	E-Sub	8,304	35	1,587	2,461	E-Sub	10,271	88	883	713	E-Sub	12,153	141	700	260
Q = 800 Million Btu/hr															
Regulatory Baseline (2.5 lb/Million Btu)	E-Sub	12,876	884	-	-	E-Sub	16,147	2,208	-	-	E-Sub	19,300	3,532	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	B-Sub	13,359	400	998	-	B-Sub	17,354	999	998	-	B-Sub	21,234	1,598	1,000	-
Percent Reduction (FGD)[e] (90% Reduction)	E-Sub	14,168	70	1,587	2,452	E-Sub	17,941	177	883	714	E-Sub	21,576	263	701	260

[a]Based on a capacity factor of 0.6 and zero cost for nonfossil fuel.

[b]Allowing dilution at baseline results in a 12.5 lb SO_2/million Btu limit. Since this type of coal is not available, emissions are based on the lowest cost coal available.

[c]Compared to Regulatory Baseline.

[d]Compared to less stringent alternative.

[e]The annual emissions are based on a 92% removal efficiency. The additional 2% accounts for FGD variability.

commercial-institutional steam generating units of more than 250 million Btu/hour heat input capacity (i.e., 40 CFR Part 60 Subpart D) and regulatory requirements contained in SIP's, dilution of the SO_2 emissions resulting from combustion of fossil fuel with the gases resulting from combustion of nonfossil fuel is permitted.

Existing regulations permit one to add the heat input supplied to a mixed fuel-fired steam generating unit supplied by a nonfossil fuel to that supplied by a fossil fuel in determining compliance. Since existing regulations are generally written in terms of grams (or pounds) of SO_2 per unit of heat input to the steam generating unit, including the heat input supplied by the nonfossil fuel inherently provides an emission credit for a mixed fuel-fired steam generating unit.

Typically, for example, many existing regulations limit SO_2 emissions from coal-fired steam generating units to 1.2 lb SO_2/million Btu. To achieve this emission limit, a coal-fired steam generating unit is essentially required to fire a low sulfur coal or install an FGD system. Because of the emission credit inherently provided by this type of regulation, however, mixed fuel-fired steam generating units are not required to fire a low sulfur coal or install an FGD system, but are permitted to fire medium or even high sulfur coals.

A mixed fuel-fired steam generating unit firing a fuel mixture of 20 percent coal and 80 percent nonfossil fuel, for example, would only be required to fire a coal containing 6.0 lb SO_2/million Btu or less. As illustrated below, however, as the proportion of coal in the fuel mixture increases, the sulfur content of the coal that can be fired decreases:

Fossil/Nonfossil Fuel Mixture	Maximum Coal Sulfur Content (lb SO_2/million Btu)
20% Fossil/80% Nonfossil	6.0
40% Fossil/60% Nonfossil	3.0
50% Fossil/50% Nonfossil	2.4
60% Fossil/40% Nonfossil	2.0
80% Fossil/20% Nonfossil	1.5

The reasonableness of emission credits for mixed fuel-fired steam generating units are examined in Section 5.0. Except under the regulatory baseline, however, the analysis discussed in this section assumes no emission credits.

As a result, regardless of the proportion of coal fired in the fuel mixture, mixed fuel-fired steam generating units must fire low sulfur coal or install an FGD system to meet the requirements of an alternative control level based on the use of low sulfur coal. As mentioned, however, this is not the case under the regulatory baseline. As illustrated above, as the proportion of coal in the fuel mixture increases, a mixed fuel-fired steam generating unit must fire a lower sulfur coal to meet the regulatory baseline of 2.5 lb SO_2/million Btu.

Consequently, as the proportion of coal fired in the fuel mixture varies, the incremental costs and SO_2 emission reductions between the regulatory baseline and an alternative control level based on the use of low sulfur fuel can also vary. As a result, the average cost effectiveness of SO_2 control for a low sulfur fuel alternative can vary as the proportion of coal fired in the fuel mixture changes.

Tables 5, 6, and 7 also present the average and incremental cost effectiveness of SO_2 control associated with an alternative control level requiring a 90 percent reduction in SO_2 emissions. The average cost effectiveness of SO_2 control ranges from as low as $462/ton for the largest mixed fuel-fired steam generating unit firing a fuel mixture of 80 percent coal and 20 percent nonfossil fuel in Region I, to as high as $2,333/ton for the smallest mixed fuel-fired steam generating unit firing a fuel mixture of 20 percent coal and 80 percent nonfossil fuel in Region X. As expected, the average cost effectiveness of a percent reduction in SO_2 emissions generally becomes more favorable as the size of a mixed fuel-fired steam generating unit increases. This is due to the economies of scale of the FGD system. Because the analysis for the 800 million Btu/hour steam generating unit is based on the use of two shop fabricated 400 million Btu/hour FGD units, the average cost effectiveness is essentially the same for steam generating units of 400 and 800 million Btu/hour heat input capacity.

The average cost effectiveness of SO_2 control associated with an alternative control level requiring a percent reduction in SO_2 emissions also varies as the amount of coal fired in the fuel mixture varies. Generally, the average cost effectiveness improves as the amount of coal fired in the fuel mixture increases.

This is not always the case, however, as shown in Region IV in progressing from a fuel mixture of 50 percent coal and 50 percent nonfossil fuel to a fuel mixture of 80 percent coal and 20 percent nonfossil fuel. In this case, the average cost effectiveness of SO_2 control associated with an alternative control level requiring a percent reduction in SO_2 emissions deteriorates rather than improves.

In this particular case, a lower sulfur coal is required under the regulatory baseline in a fuel mixture consisting of 80 percent coal and 20 percent nonfossil fuel than in a fuel mixture consisting of 50 percent coal and 50 percent nonfossil fuel. Consequently, the SO_2 emission reduction achieved by an alternative control level requiring a 90 percent reduction in SO_2 emissions is less for the 80 percent coal/20 percent nonfossil fuel mixture than for the 50 percent coal/50 percent nonfossil fuel mixture. As a result, the average cost effectiveness of SO_2 control deteriorates in progressing from the 50 percent coal/50 percent nonfossil fuel mixture to the 80 percent coal/20 percent nonfossil fuel mixture.

As shown in the tables, the incremental cost effectiveness of achieving a 90 percent reduction in SO_2 emissions over meeting an emission limit of 1.2 lb SO_2/million Btu is almost identical for units with heat input capacities of 400 and 800 million Btu/hour. This is primarily due to the fact, discussed above, that for an 800 million Btu/hour unit, the FGD cost is represented by two 400 million Btu/hour FGD units. The incremental cost effectiveness of SO_2 control for a 150 million Btu/hour steam generating unit, however, is higher in all cases than those associated with larger steam generating units.

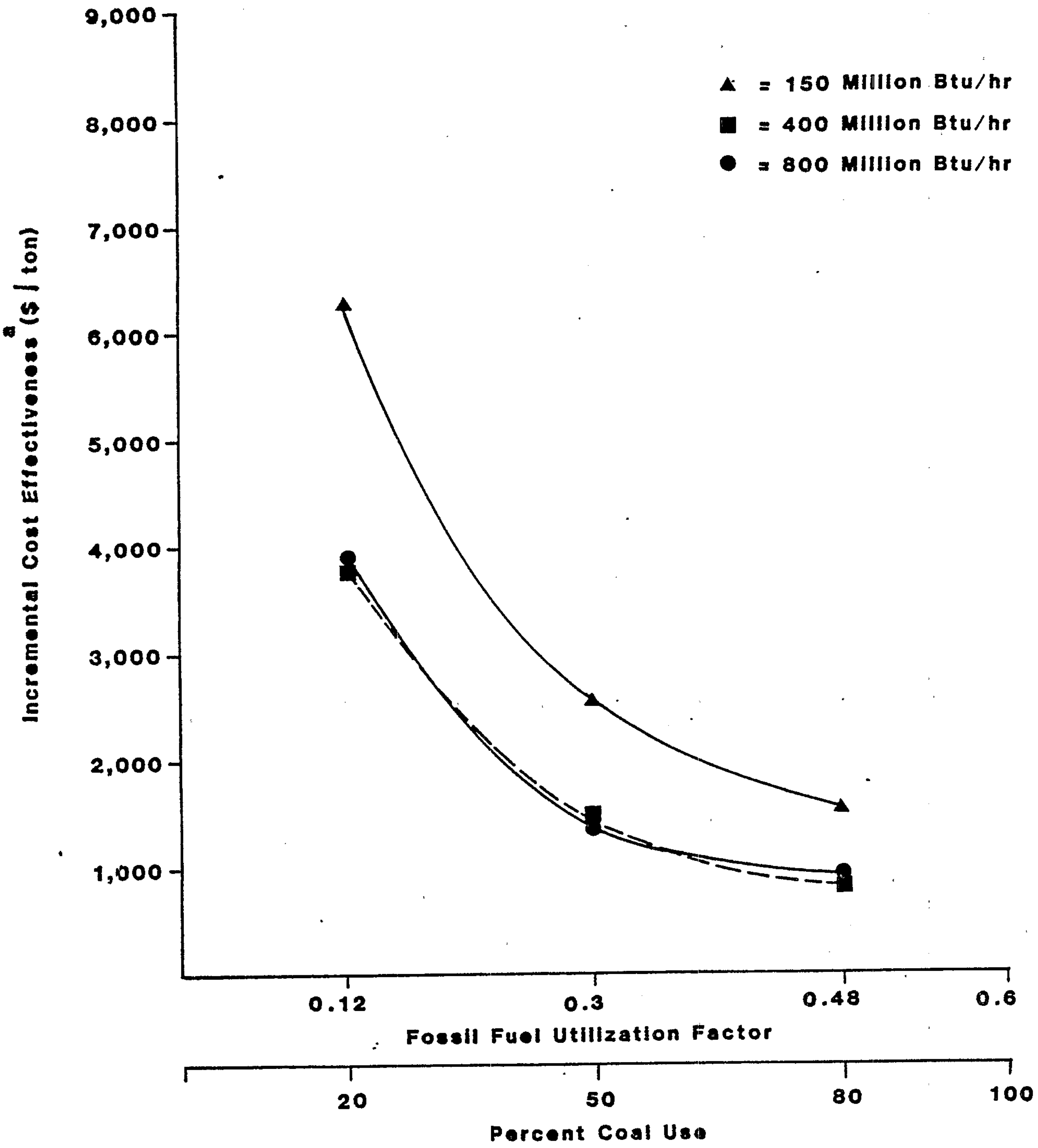
The incremental cost effectiveness also improves as the percentage of coal fired increases. This is as one would expect, because without an emission credit an alternative control level based on the use of low sulfur fuel always requires the combustion of a low sulfur fuel or the use of an FGD system. Thus, in examining the incremental differences between an alternative control level based on the use of low sulfur coal and an alternative control level requiring a percent reduction in SO_2 emissions, one is always comparing the costs and emissions associated with firing a low sulfur fuel with the costs and emissions associated with an FGD system. In addition, FGD systems installed on mixed fuel-fired steam generating units would be designed to accommodate firing of fossil fuel at full load to provide maximum fuel use flexibility. Thus, the costs of FGD systems installed on units firing small amounts of fossil fuel would be similar to those installed on mixed fuel-fired units that fire large amounts of fossil fuel relative to nonfossil fuel. However, the potential SO_2 emission reductions obtainable from units burning relatively larger amounts of fossil fuel relative to nonfossil fuel are much greater than for units burning mostly nonfossil fuel. As a result, for mixed fuel-fired steam generating units that fire only small amounts of fossil fuel, the costs of achieving a percent reduction in SO_2 emissions are relatively high in proportion to the resulting emission reductions. Conversely, as the amount of coal fired in the fuel mixture increases, the FGD system costs demonstrate economies of scale and the SO_2 emission reductions achieved increase. The incremental cost effectiveness of SO_2 control, therefore, improves.

The amount of fossil fuel fired in a steam generating unit can be expressed in terms of a fossil fuel utilization factor. This represents the percentage of the rated steam generating unit heat input capacity that is supplied by fossil fuel. The fossil fuel utilization factor is, therefore, calculated on the basis of the amount of fossil fuel that is actually fired compared to the maximum amount of fuel that could be fired in the steam generating unit. For example, a 400 million Btu/hour mixed fuel-fired steam generating unit operating at an annual capacity factor of 0.6 is firing 240 million Btu/hour heat input on an annual basis. If this unit fires 20 percent fossil fuel and 80 percent nonfossil fuel, the heat input supplied from fossil fuel is 48 million Btu/hour on an annual basis. This represents 12 percent of the potential total annual heat input to the steam generating unit, or a fossil fuel utilization factor of 0.12. Similarly, a mixed fuel-fired steam generating unit operating at an annual capacity factor of 0.6 and firing 50 percent fossil fuel/50 percent nonfossil fuel mixture would have a fossil fuel utilization factor of 0.3, and a unit firing 80 percent fossil fuel and 20 percent nonfossil fuel would have a fossil fuel utilization factor of 0.48.

Figures 1, 2, and 3 illustrate the incremental cost effectiveness of an alternative control level requiring a 90 percent reduction in SO_2 emissions over an alternative control level based on the use of low sulfur fuel as a function of the fossil fuel utilization factor for mixed fuel-fired steam generating units operating at an annual capacity utilization factor of 0.6. Fossil fuel utilization factors of 0.12, 0.3, and 0.48 were examined and are shown in the figures.

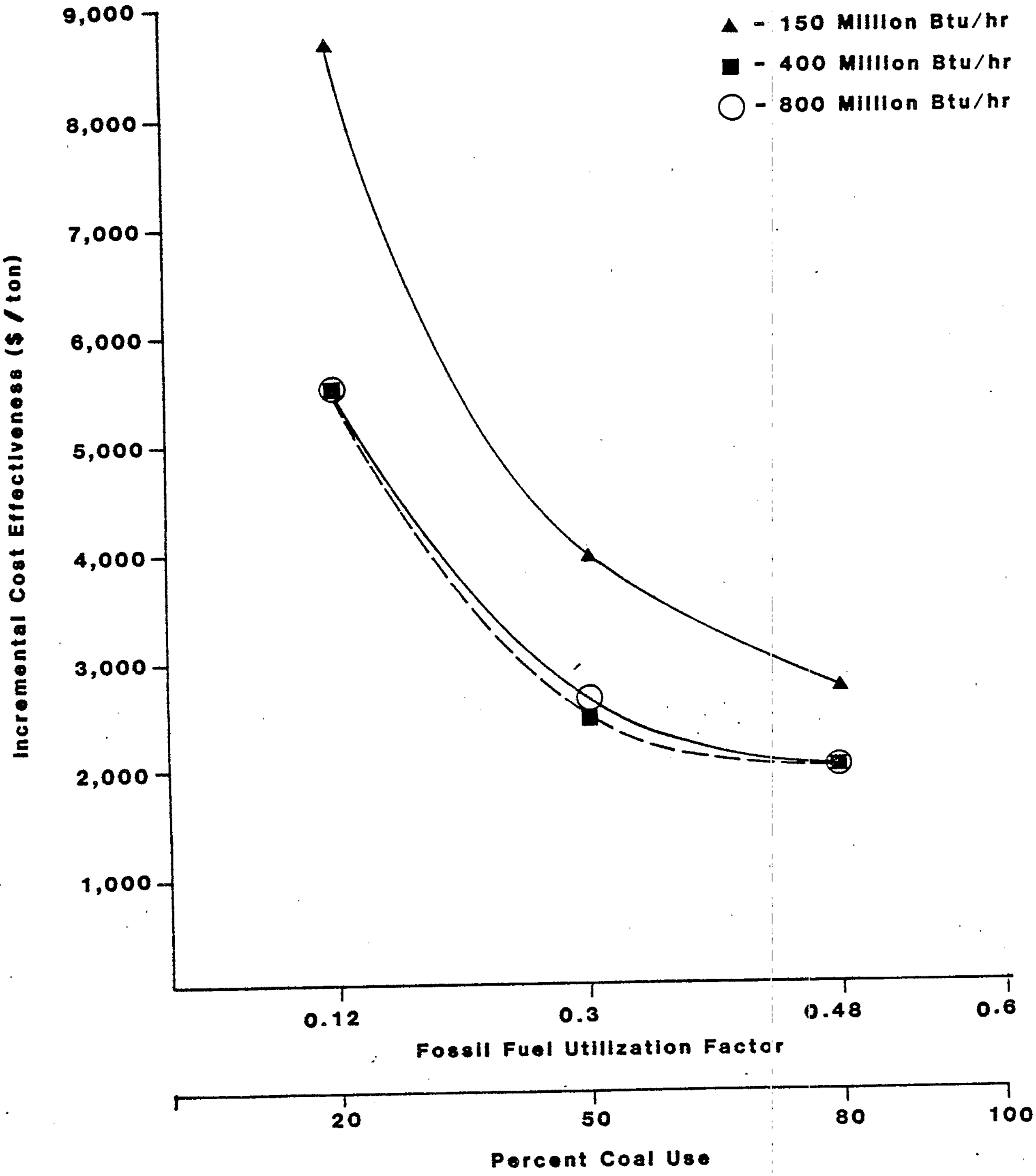
The incremental cost effectiveness of achieving a percent reduction in SO_2 emissions varies considerably with varying amounts of coal fired in the steam generating unit. As shown in the figures, as the fossil fuel utilization factor increases, the incremental cost effectiveness decreases. A more rapid decrease in incremental cost effectiveness occurs in progressing from a fossil fuel utilization factor of 0.12 to a fossil fuel utilization factor of 0.3 than in progressing from a fossil fuel utilization factor of 0.3 to a fossil fuel utilization factor of 0.6. Thus, the fossil fuel utilization factor exerts an important influence on the costs of achieving a percent reduction in SO_2 emissions.

Figure 4 illustrates the regional differences in the incremental cost effectiveness associated with an alternative control level requiring a 90 percent reduction in SO_2 emissions for a 400 million Btu/hour steam generating unit. This figure shows that the incremental cost effectiveness of an alternative control level requiring a 90 percent reduction in SO_2 emissions over an alternative based on the use of low sulfur fuel in Region IV is about 30 percent higher than in Region I and about 60 percent higher than in Region X. These differences are due to regional variations in coal sulfur contents and prices. The high incremental costs associated with achieving a percent reduction in SO_2 emissions in Region IV can be



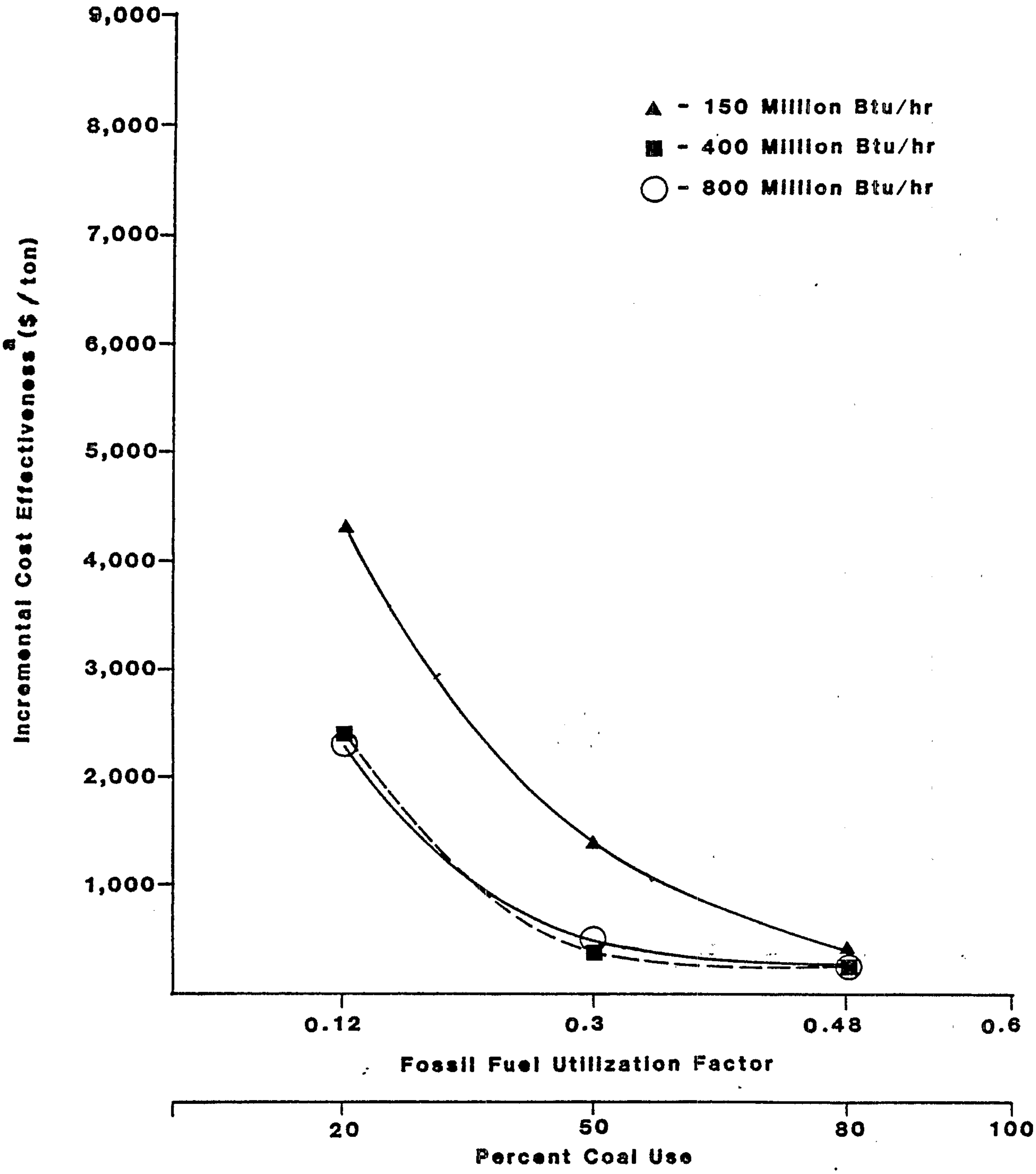
[a]Over alternative control level based on the use of low sulfur coal.

Figure 1. Incremental Cost Effectiveness of a Percent Reduction Requirement for Mixed Fuel-Fired Steam Generating Units Firing Coal in Region I.



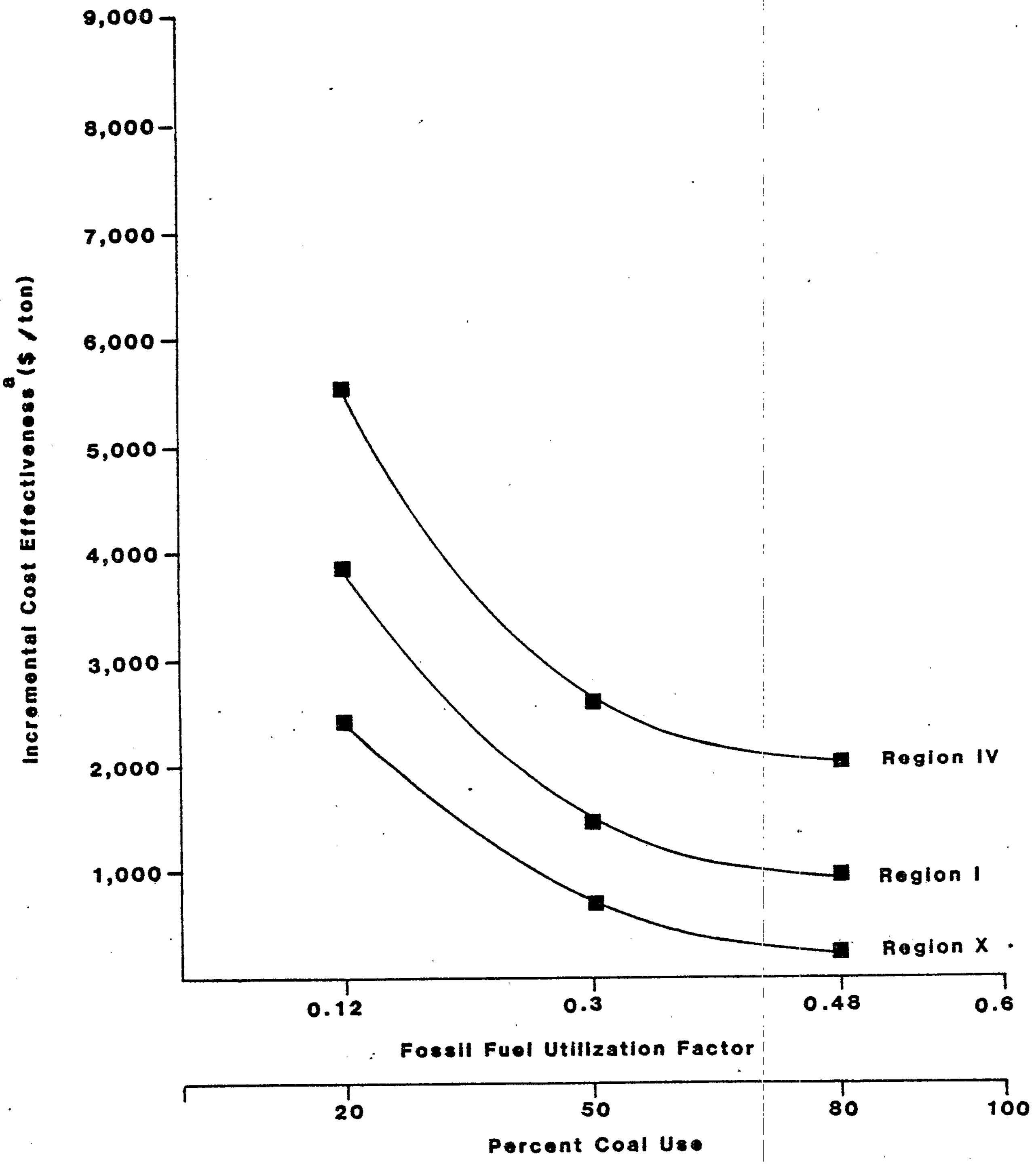
[a]Over alternative control level based on the use of low sulfur coal.

Figure 2. Incremental Cost Effectiveness of a Percent Reduction Requirement for Mixed Fuel-Fired Steam Generating Units Firing Coal in Region IV.



[a]Over alternative control level based on the use of low sulfur coal.

Figure 3. Incremental Cost Effectiveness of a Percent Reduction Requirement for Mixed Fuel-Fired Steam Generating Units Firing Coal in Region X.



[a]Over alternative control level based on the use of low sulfur coal.

Figure 4. Incremental Cost Effectiveness of a Percent Reduction Requirement for a 400 million Btu/hour Mixed Fuel-Fired Steam Generating Unit Firing Coal.

attributed to the fact that a higher sulfur coal is typically fired in this region. Under a standard requiring a 90 percent reduction in SO_2 emissions, steam generating units in Region IV will likely fire a Type H bituminous coal having typical uncontrolled SO_2 emissions of about 5.5 lb/million Btu. A 90 percent reduction would reduce these emissions to 0.55 lb SO_2/million Btu. In contrast, steam generating units in Region I will likely fire a coal having typical uncontrolled SO_2 emissions of about 4.2 lb/million Btu, and the uncontrolled emissions from a unit in Region X would typically be about 2.1 lb/million Btu. A 90 percent reduction in Regions I and X, therefore, will result in SO_2 emissions of 0.42 and 0.21 lb/million Btu, respectively. Compared to a low sulfur coal emission limit of 1.2 lb SO_2/million Btu, steam generating units in Regions I and X realize greater emission reductions under a 90 percent reduction requirement than those in Region IV. Therefore, a 90 percent reduction requirement would be more cost effective in Regions I and X than in Region IV.

The annualized costs presented in Tables 5, 6, and 7 assume that the price of nonfossil fuel is zero cost. For a case where nonfossil fuel has a price, annualized costs will increase. However, since these increased annualized costs cancel out in comparing incremental impacts between alternatives, the average and incremental cost effectiveness values cited above and presented in Tables 5, 6, and 7 would remain unchanged. To illustrate this, Table 8 summarizes the costs and cost effectiveness of SO_2 control for a 150 million Btu/hour mixed fuel-fired steam generating unit firing a fuel mixture of 20 percent coal and 80 percent nonfossil fuel in Regions I, IV, and X. The annualized costs presented in this table assume that the cost of the nonfossil fuel is equal to the cost of the lowest price coal in each region on a $/million Btu heating value basis. This table shows that although the total annualized costs are higher than those presented in Tables 5, 6, and 7, the cost effectiveness values remain unchanged.

TABLE 8. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR A 150 MILLION BTU/HR 20 PERCENT COAL/80 PERCENT NONFOSSIL MIXED FUEL-FIRED STEAM GENERATING UNIT (ASSUMES A NON-ZERO COST FOR THE NONFOSSIL FUEL)[a]

	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness ($/ton)
Region I				
Regulatory Baseline (2.5 lb/million Btu)	5,664	328	-	-
Low Sulfur Coal (1.2 lb/million Btu)	5,759	75	375	-
Percent Reduction (FGD) (90% Reduction)	6,068	26	1,338	6,306
Region IV				
Regulatory Baseline (2.5 lb/million Btu)	5,239	437	-	-
Low Sulfur Coal (1.2 lb/million Btu)	5,329	75	248	-
Percent Reduction (FGD) (90% Reduction)	5,678	35	1,092	8,725
Region X				
Regulatory Baseline (2.5 lb/million Btu)	4,905	166	-	-
Low Sulfur Coal (1.2 lb/million Btu)	4,995	75	989	-
Percent Reduction (FGD) (90% Reduction)	5,262	13	2,333	4,306

[a]Nonfossil fuel cost set equal to the lowest price coal available in each region.

Oil/Nonfossil Mixed Fuel-Fired Steam Generating Units

Table 9 presents the results of the cost analysis for oil/nonfossil mixed fuel-fired steam generating units in Region I. Mixed fuel-fired units were only examined in Region I because the price premium for a low sulfur oil compared to a high sulfur oil is essentially constant for all regions.[5]

The average cost effectiveness of SO_2 control associated with an alternative control level based on the use of low sulfur oil is less than $640/ton. As expected, the average cost effectiveness of SO_2 control under this alternative control level remains constant with mixed fuel-fired steam generating unit size. In addition, unlike the situation discussed above for mixed fuel-fired steam generating units firing coal, the highest sulfur oil available is always fired in the oil/nonfossil fuel mixture under the regulatory baseline regardless of the proportion of oil in this fuel mixture. Consequently, the average cost effectiveness of SO_2 control also remains constant as the proportion of oil fired in the fuel mixture varies.

Table 9 also presents the average and incremental cost effectiveness of SO_2 control associated with an alternative control level requiring a percent reduction in SO_2 emissions. The average cost effectiveness of an SO_2 emissions percent reduction requirement ranges from as little as $467/ton for the largest mixed fuel-fired steam generating unit firing a fuel mixture containing 80 percent oil/20 percent nonfossil fuel, to as much as $1,505/ton for the smallest mixed fuel-fired unit firing a fuel mixture of 20 percent oil/80 percent nonfossil fuel. Similarly, the incremental cost effectiveness of SO_2 control ranges from as low as $0/ton to as high as $5,000/ton. As expected, the average and incremental cost effectiveness of SO_2 control associated with an alternative control level requiring a percent reduction in SO_2 emissions improves as the size of the mixed fuel-fired steam generating unit increases or as the proportion of oil fired in the oil/nonfossil fuel mixture increases. This is due to the economies of scale experienced by the FGD system.

Figure 5 illustrates the incremental cost effectiveness of an alternative control level requiring a 90 percent reduction in SO_2 emissions

TABLE 9. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR OIL/NONFOSSIL MIXED FUEL-FIRED STEAM GENERATING UNITS IN REGION I

Unit Size/ Control Alternative	20 Percent Oil/80 Percent Nonfossil Fuel: Oil Type (lb SO_2/10^6 Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[a,b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	50 Percent Oil/50 Percent Nonfossil Fuel: Oil Type[a] (lb SO_2/10^6 Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[a] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	80 Percent Oil/20 Percent Nonfossil Fuel: Oil Type (lb SO_2/10^6 Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[a] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Q = 150 Million Btu/hr															
Regulatory Baseline (3.0 lb/Million Btu)	3.0	3,713	237	-	-	3.0	5,002	591	-	-	3.0	6,267	946	-	-
Low Sulfur Oil (0.8 lb/Million Btu)	0.8	3,821	63	621	-	0.8	5,279	158	640	-	0.8	6,711	252	640	-
Percent Reduction (FGD)[f] (90% Reduction)	3.0	4,041	19	1,505	5,000	3.0	5,445	47	814	1,495	3.0	6,801	76	614	511
Q = 400 Million Btu/hr															
Regulatory Baseline (3.0 lb/Million Btu)	3.0	8,353	631	-	-	3.0	11,687	1,577	-	-	3.0	14,986	2,523	-	-
Low Sulfur Oil (0.8 lb/Million Btu)	0.8	8,643	168	626	-	0.8	12,426	420	639		0.8	16,162	673	636	-
Percent Reduction (FGD)[f] (90% Reduction)	3.0	8,960	50	1,045	2,686	3.0	12,539	126	587	384	3.0	16,070	202	467	0[e]
Q = 800 Million Btu/hr															
Regulatory Baseline (3.0 lb/Million Btu)	3.0	14,539	1,262	-	-	3.0	21,130	3,154	-		3.0	27,651	5,046	-	-
Low Sulfur Oil (0.8 lb/Million Btu)	0.8	15,119	336	626	-	0.8	22,607	841	639	-	0.8	30,003	1,346	636	-
Percent Reduction (FGD)[f] (90% Reduction)	3.0	15,753	100	1,045	2,686	3.0	22,834	252	587	385	3.0	29,819	404	467	0[e]

[a]Based on a capacity factor of 0.6 and zero cost for nonfossil fuel.

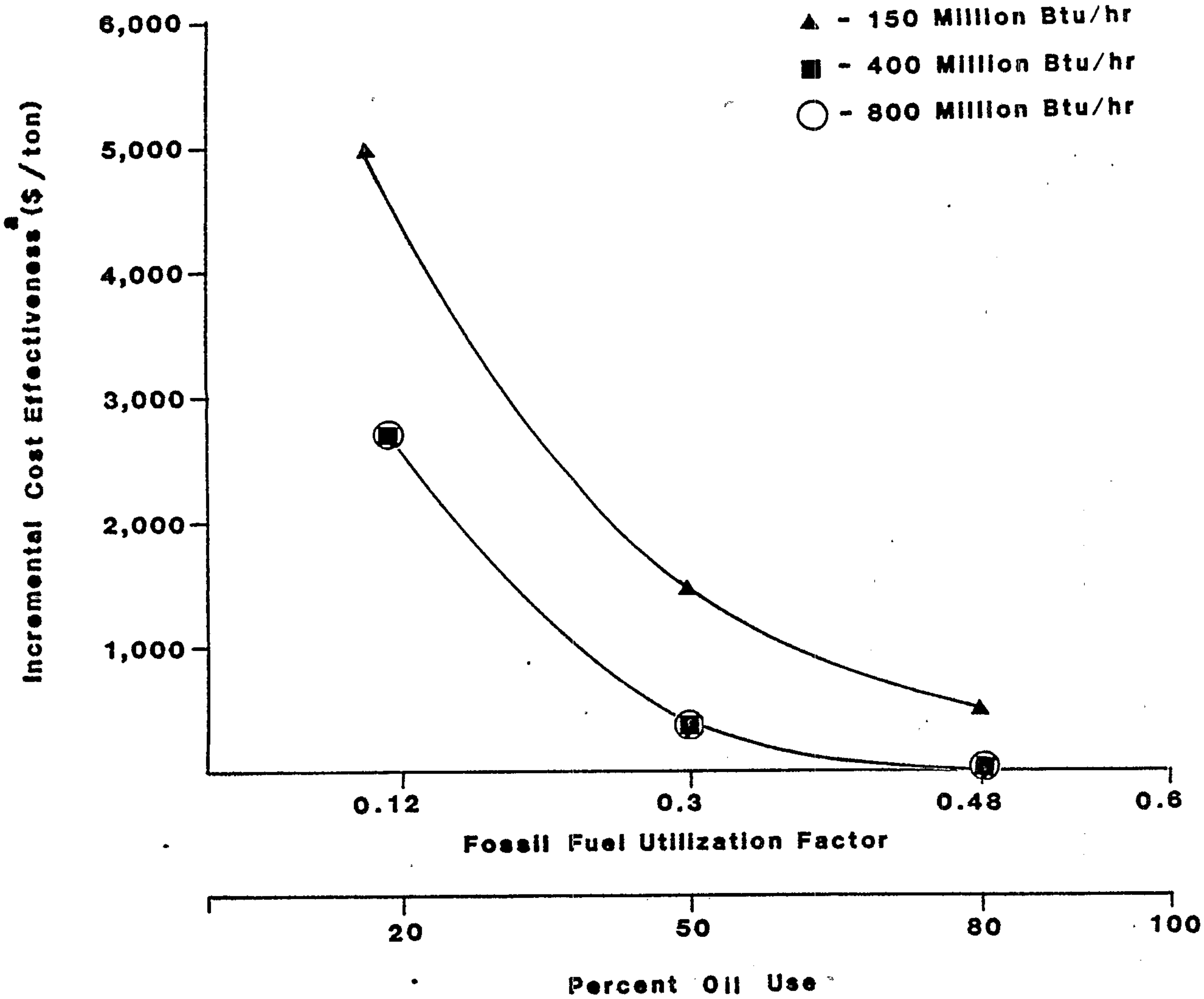
[b]Allowing dilution at baseline results in a 15.0 lb SO_2/million Btu limit. Since this type of oil is not available, emissions are based on the lowest cost oil available.

[c]Compared to Regulatory Baseline.

[d]Compared to less stringent alternative.

[e]The low sulfur alternative costs more than the percent reduction alternative, therefore the incremental cost effectiveness is zero.

[f]The annual emissions are based on a 92% removal efficiency. The additional 2% accounts for FGD variability.



[a]Over alternative control level based on the use of low sulfur oil.

Figure 5. Incremental Cost Effectiveness of a Percent Reduction Requirement for Mixed Fuel-Fired Steam Generating Units Firing Oil.

over an alternative control level based on the use of low sulfur oil as a function of the fossil fuel utilization factor for mixed fuel-fired steam generating units firing oil and operating at an annual capacity utilization factor of 0.6. As with mixed fuel-fired steam generating units firing coal, fossil fuel utilization factors of 0.12, 0.3, and 0.48 were examined.

As shown in the figure, as the fossil fuel utilization factor increases, the incremental cost effectiveness decreases. As discussed above for mixed fuel-fired steam generating units firing coal, this decrease is most rapid at low fossil fuel utilization factors. Thus, the fossil fuel utilization factor exerts an important influence on the costs of achieving a percent reduction in SO_2 emissions.

The annualized costs presented in Table 9 assume that the price of nonfossil fuel is zero. As discussed earlier for mixed fuel-fired steam generating units firing coal, if the nonfossil fuel has a non-zero price, the overall annualized costs will rise, but the incremental impacts associated with SO_2 control will not change.

4.0 NATIONAL IMPACTS

This section examines the national impacts of NSPS limiting SO_2 emissions from new industrial-commercial-institutional mixed fuel-fired steam generating units. The national impact analysis utilizes the projected population of new mixed fuel-fired steam generating units described in Section 2.0. To estimate these impacts, the total costs associated with each projected new mixed fuel-fired steam generating unit firing coal/nonfossil, oil/nonfossil, or natural gas/nonfossil mixtures, including the costs associated with environmental regulations, were compared on an after-tax net present value (NPV) basis over a 15-year investment period. The lowest cost means of complying with each regulatory alternative examined was then determined for each mixed fuel-fired steam generating unit. These results were then aggregated to yield national projections in 1990 of annualized costs, SO_2 emissions, and solid and liquid wastes associated with mixed fuel-fired steam generating units.

Selection of Regulatory Alternatives

The regulatory baseline represents the level of control required by existing SIP's. Currently, the average SO_2 emission limit required under SIP's is approximately 2.5 lb/million Btu heat input. Thus, a regulatory baseline of 2.5 lb/million Btu heat input was selected for the analysis of national impacts for new mixed fuel-fired steam generating units. Also, as discussed in the previous section, the regulatory baseline permits dilution of the SO_2 emissions resulting from combustion of fossil fuels with the gases resulting from combustion of nonfossil fuels to comply with this emission limit. Dilution is not permitted, however, to comply with the various regulatory alternatives examined. The reasonableness of dilution or "emission credits" for mixed fuel-fired steam generating units is examined in Section 5.0.

This national impact analysis examined two alternative control levels: an alternative requiring a low sulfur fuel and an alternative requiring 90 percent reduction in SO_2 emissions. Also, this analysis considered two size categories of mixed fuel-fired steam generating units: units greater than 250 million Btu/hour heat input capacity; and units between 100 and 250 million Btu/hour heat input capacity. Table 10 presents the four regulatory alternatives examined.

After-Tax NPV of Alternative Fuel Mixtures and Emission Control Systems

Table 11 presents the after-tax NPV of alternative fuel mixtures and emission control systems for the regulatory baseline, for an alternative control level based on the use of low sulfur fossil fuel, and for an alternative control level requiring a 90 percent reduction in SO_2 emissions. These results are presented for a 150 million Btu/hour steam generating unit firing 100 percent fossil fuel as well as a 20 percent fossil/80 percent nonfossil fuel mixture. The analysis for this particular fuel mixture and size of steam generating unit are presented because this combination results in conservative estimates of impacts associated with SO_2 control. As the steam generating unit size and amount of fossil fuel fired in the mixture increases, the cost of SO_2 control as a percent of total steam generating unit costs decreases.

The results presented in this table show that at the regulatory baseline and for alternative control levels based on the use of low sulfur fuels or requiring a percent reduction in SO_2 emissions, new projected mixed fuel-fired steam generating units will continue to fire fossil/nonfossil fuel mixtures. In addition, all units are expected to select coal as the fossil fuel to fire in the fossil/nonfossil fuel mixture. This is to be expected because a steam generating unit capable of firing a nonfossil fuel on a grate is also capable of firing coal. Thus, there are little capital costs associated with the steam generating unit to be saved by firing natural gas or oil with the nonfossil fuel.

As mentioned, Table 11 also shows that mixed fuel-fired steam generating units do not "switch" fuels even under a regulatory alternative requiring a 90 percent reduction in SO_2 emissions. One exception was found

TABLE 10. REGULATORY ALTERNATIVES

Mixed Fuel-Fired Steam Generating Units

	Steam Generating Unit Size (million Btu/hr)	
	100 - 250	>250
Baseline	Baseline[a]	Baseline
Alternative I	Baseline	LSF[b]
Alternative II	LSF	LSF
Alternative III	LSF	90% Red.[c]
Alternative IV	90% Red.	90% Red.

[a] Baseline = 2.5 lb SO_2/million Btu (SIP level)

[b] LSF = Low sulfur fuel standard (1.2 lb SO_2/million Btu for coal and 0.8 lb SO_2/million Btu for oil).

[c] % Red. = Percent reduction requirement (90% SO_2 removal).

TABLE 11. NET PRESENT VALUE FOR 150 MILLION BTU/HR NONFOSSIL/FOSSIL MIXED FUEL-FIRED STEAM GENERATING UNITS

	20% Coal/80% Nonfossil Fuel		20% Oil/80% Nonfossil Fuel		20% Natural Gas/ 80% Nonfossil Fuel		100% Fossil Fuel		
Control Alternatives	Nonfossil = Coal[a]	Nonfossil = 0	Nonfossil = Coal[a]	Nonfossil = 0	Nonfossil = Coal[a]	Nonfossil = 0	Coal	Oil	Natural Gas
Region I									
Regulatory Baseline	19,729	12,225	21,087	13,582	21,415	13,911	21,657	18,342	21,622
Low Sulfur Fuel	20,060	12,556	21,505	14,001			21,973	20,432	
Percent Reduction (90%)	21,023	13,519	22,235	14,731			22,439	20,179	
Region IV									
Regulatory Baseline	18,059	11,891	19,732	13,564	21,284	15,116	19,742	18,248	22,024
Low Sulfur Fuel	18,408	12,240	20,150	13,982			20,389	20,329	
Percent Reduction (90%)	19,462	13,294	20,881	14,713			21,478	20,081	
Region X									
Regulatory Baseline	16,746	11,812	18,221	13,317	20,086	15,182	17,724	17,006	20,809
Low Sulfur Fuel	17,075	12,171	18,656	13,752			19,371	19,182	
Percent Reduction (90%)	17,861	12,957	19,370	14,466			19,164	18,847	

[a]Nonfossil fuel cost equals that of the lowest price coal in the region.

in Region I when the price of the nonfossil fuel was assumed equal to that of coal. In this case the steam generating unit would switch to firing 100 percent oil. It is generally not expected, however, that the price of nonfossil fuel would ever be as high as the price of coal. Consequently, this one exception is considered to be highly unlikely and "fuel switching" can be generally ruled out.

Analysis of Regulatory Alternatives

Table 12 summarizes the projected national impacts of the four regulatory alternatives selected for analysis. The total annualized costs shown assume a zero cost for nonfossil fuel. As explained earlier in Section 3.0, although the total annualized costs for each alternative would be higher if the analysis was based on a non-zero cost for nonfossil fuel, the incremental costs, or cost impacts, between regulatory alternatives would remain the same.

Table 12 shows that at the regulatory baseline the annualized costs for mixed fuel-fired steam generating units are about $424.8 million per year and the annual SO_2 emissions are about 69,100 tons per year. Under Regulatory Alternative 1, annualized costs would be $445.9 million per year with annual SO_2 emissions of 24,300 tons per year and an average cost effectiveness of $471/ton. For Regulatory Alternative 2, annualized costs would be $446.3 million per year and annual SO_2 emissions would be reduced to 23,200 tons per year, for an average cost effectiveness of $468/ton. The incremental cost effectiveness of Regulatory Alternative 2 over Regulatory Alternative 1 is $364/ton.

Under Regulatory Alternative 3, annualized costs would be about $470.0 million per year and annual emissions would be reduced to about 8,200 tons per year. Under Regulatory Alternative 4, annualized costs would be $471.6 million per year with annual SO_2 emissions of only 7,900 tons per year.

The average cost effectiveness of Regulatory Alternatives 3 and 4 are $742/ton and $765/ton, respectively. The incremental cost effectiveness of Regulatory Alternative 3 over Regulatory Alternative 2 is $1,580/ton. The

TABLE 12. NATIONAL IMPACTS OF REGULATORY ALTERNATIVES

Mixed Fuel-Fired Steam Generating Units

Regulatory Alternative	Annual Emissions (1,000 tons/yr)	Annualized Costs ($Million/yr)	Cost Effectiveness ($/ton)		Quantity of Fuel Scrubbed (Trillion Btu/yr)		Boiler Liquid Waste (Million ft^3/yr)	Boiler Solid Waste (1,000 tons/yr)
			Average	Incremental	Fossil	Nonfossil		
Baseline	69.1	424.8	-	-	-	-	40	284
Alternative 1	24.3	445.9	471	-	-	-	40	281
Alternative 2	23.2	446.3	468	364	-	-	40	281
Alternative 3	8.2	470.0	742	1,580	48	47	149	286
Alternative 4	7.9	471.6	765	5,333	49	50	151	286

incremental cost effectiveness of Regulatory Alternative 4 over Regulatory Alternative 3 is $5,333/ton.

The high incremental cost effectiveness of Regulatory Alternative 4 over Regulatory Alternative 3 can be explained by examining the alternatives themselves. Under Regulatory Alternative 3, only steam generating units with heat input capacities greater than 250 million Btu/hour would be required to achieve a percent reduction in SO_2 emissions. Under Regulatory Alternative 4, steam generating units with heat input capacities between 100 and 250 million Btu/hour would also be required to achieve a percent reduction in SO_2 emissions. As discussed in Section 2.0, only five new mixed fuel-fired steam generating units with heat input capacities in this range are expected to be constructed in the five-year period ending in 1990. On an annual basis, the potential emission reductions obtainable from these mixed fuel-fired steam generating units with heat input capacities less than 250 million Btu/hour is quite small, even under a standard requiring a percent reduction in SO_2 emissions. In addition, all of these units are expected to fire very small amounts of fossil fuel in relation to nonfossil fuel (on the order of 20 percent). As shown previously in Figures 1 to 3, the incremental cost effectiveness of achieving a percent reduction in SO_2 emissions over the use of low sulfur fuel is very high for steam generating units firing 20 percent fossil fuel/80 percent nonfossil fuel mixtures.

As discussed above, the amount of fossil fuel fired on an annual basis compared to the rated annual heat input capacity for a particular steam generating unit is referred to as the fossil fuel utilization factor. Table 13 illustrates the relationship between incremental cost effectiveness values and fossil fuel utilization factors. A set of regulatory alternatives was structured, ranging from establishing an emission limit based on the use of low sulfur fuel for all mixed fuel-fired steam generating units to requiring all mixed fuel-fired steam generating units to achieve a percent reduction in SO_2 emissions. Within this range were alternatives requiring percent reduction for steam generating units with fossil fuel utilization factors above 0.48 and the use of low sulfur fuels for those units with fossil fuel utilization factors of 0.48 or less;

TABLE 13. NATIONAL IMPACTS: MIXED FUEL-FIRED STEAM GENERATING UNITS IMPACTS AS A FUNCTION OF FOSSIL FUEL UTILIZATION FACTOR

Alternative	Annual Emissions (1,000 tons/year)	Annualized Costs ($ million)	Average Cost Effectiveness ($/ton)	Incremental Cost Effectiveness[b] ($/ton)
Baseline (2.5 lb SO_2/million Btu)	69.1	424.8	-	-
Low Sulfur Fuel (1.2 lb SO_2/million Btu)	23.2	446.3	470	-
Percent Reduction for Fossil Fuel Utilization Factors >0.48[a]	23.2	446.3	470	0
Percent Reduction for Fossil Fuel Utilization Factors >0.30[a]	12.7	457.2	570	1,040
Percent Reduction for Fossil Fuel Utilization Factors >0.12[a]	10.7	460.2	605	1,460
Percent Reduction	7.9	471.6	765	4,150

[a]Steam generating units with fossil fuel utilization factors at or below the specified cutoff are not required to achieve a percent reduction in SO_2 emissions but must meet an emission limit of 1.2 lb SO_2/million Btu.

[b]Over next least stringent alternative.

percent reduction for steam generating units with fossil fuel utilization factors above 0.30 and the use of low sulfur fuel for units with fossil fuel utilization factors of 0.30 or less; and percent reduction for steam generating units with fossil fuel utilization factors above 0.12 and the use of low sulfur fuel for units with fossil fuel utilization factors of 0.12 or less.

As shown in Table 13, the incremental cost effectiveness of a percent reduction requirement for steam generating units with fossil fuel utilization factors above 0.48 over a low sulfur fuel requirement for these steam generating units is $0/ton of SO_2 removed. This is because no new mixed fuel-fired steam generating units were projected to fire fossil fuel in amounts exceeding 48 percent of their rated annual capacity; therefore, no impacts were projected. The incremental cost effectiveness of a percent reduction requirement for steam generating units with fossil fuel utilization factors above 0.30 and a low sulfur fuel requirement for units with fossil fuel utilization factors of 0.30 or less, over a percent reduction requirement for only those units wit fossil fuel utilization factors above 0.48, is $1,040/ton of SO_2 removed. The incremental cost effectiveness of a percent reduction requirement for steam generating units with fossil fuel utilization factors above 0.12 and a low sulfur fuel requirement for units with fossil fuel utilization factors of 0.12 or less, over a percent reduction requirement for only those units with fossil fuel utilization factors above 0.30, is $1,460/ton of SO_2 removed. The incremental cost effectiveness of requiring all mixed fuel-fired steam generating units to achieve a percent reduction in SO_2 emissions over a percent requirement for only those units with fossil fuel utilization factors above 0.12 is $4,150/ton of SO_2 removed.

5.0 CONSIDERATION OF EMISSION CREDITS

The SO_2 emissions resulting from the combustion of nonsulfur-bearing fuels, such as wood, municipal solid waste, natural gas, and agricultural waste products, are negligible. In terms of SO_2 emissions, therefore, there are environmental benefits associated with combustion of fuel mixtures containing nonsulfur-bearing fuels. Emissions of SO_2 from steam generating units firing mixtures of coal or oil with nonsulfur-bearing fuels are lower than emissions from coal- or oil-fired steam generating units operating at the same heat input firing the same coal or oil.

The existing NSPS for industrial-commercial-institutional steam generating units with greater than 250 million Btu/hour heat input capacity (i.e., 40 CFR Part 60 Subpart D) and existing SIP's provide "emission credits" for mixed fuel-fired steam generating units. An emission credit for mixed fuel-fired steam generating units provides a "credit" toward the emission limits or percent reduction requirements included in a standard for the "dilution" of SO_2 emissions resulting from combustion of sulfur-bearing fossil fuels by the gases resulting from combustion of nonsulfur-bearing fuels. Such an emission credit permits higher SO_2 emissions from mixed fuel-fired steam generating units and results in the same level of emissions from both a mixed fuel-fired steam generating unit and a fossil fuel-fired steam generating unit operating at the same heat input. The difference in SO_2 emissions mentioned above between these two types of steam generating units is eliminated and, as a result, any environmental benefit is also eliminated.

Table 14 illustrates how an emission credit for mixed fuel-fired steam generating units would be incorporated into standards based on the use of low sulfur fuel or standards requiring a percent reduction in SO_2 emissions. The magnitude of the emission credit is determined by dividing the total heat input supplied to the steam generating unit by the heat input supplied by the sulfur-bearing fossil fuel.

If standards based on the use of low sulfur fuels limited SO_2 emissions from coal combustion to 1.2 lb SO_2/million Btu and from oil combustion to

TABLE 14. CALCULATION OF MIXED FUEL-FIRED STEAM GENERATING UNIT EMISSION CREDIT

A. For a standard based on the use of low sulfur coal, (e.g., 1.2 lb/million Btu) an emission credit would allow the mixed fuel-fired steam generating unit to fire a higher sulfur coal.

SO_2 Emission Limit Without Emission Credit = 1.2 lb/million Btu

SO_2 Emission Limit With Emission Credit =

$$1.2 \text{ lb/million Btu} \times \left(\frac{\text{Total Heat Input}}{\text{Fossil Fuel Heat Input}} \right)$$

Example: For a 400 million Btu/hr heat input mixed fuel-fired steam generating unit operating at full capacity and firing a 50 percent coal/50 percent nonsulfur-bearing fuel mixture,

SO_2 Emission Limit With Emission Credit =

$$1.2 \text{ lb/million Btu} \times \frac{400 \text{ million Btu/hr}}{200 \text{ million Btu/hr}} = 2.4 \text{ lb/million Btu}$$

B. For a standard requiring a percent reduction in SO_2 emissions, (e.g., 90 percent) an emission credit would allow the steam generating unit to operate the flue gas desulfurization system at a lower percent removal.

SO_2 Percent Reduction Requirement Without Emission Credit = 90 percent

SO_2 Emissions Level Permitted = 100-90 = 10 percent

SO_2 Percent Reduction Requirement With Emission Credit =

$$100 - \left[10 \text{ Percent} \times \frac{\text{Total Heat Input}}{\text{Fossil Fuel Heat Input}}\right]$$

Example: For a 400 million Btu/hr heat input mixed fuel-fired steam generating unit operating at full capacity and firing a 50 percent coal/50 percent nonsulfur-bearing fuel mixture,

Percent Reduction Requirement With Emission Credit =

$$100 \text{ Percent} - \left[10 \text{ Percent} \times \frac{400 \text{ million Btu/hr}}{200 \text{ million Btu/hr}}\right] = 80 \text{ percent}$$

0.8 lb SO_2/million Btu, an emission credit would increase these emission limits to the levels shown in Table 15. Similarly, if standards required a percent reduction in SO_2 emissions of 90 percent, an emission credit would decrease this percent reduction requirement to the levels shown in Table 15.

To assess the reasonableness of emission credits for mixed fuel-fired steam generating units, the cost effectiveness of SO_2 control for these systems was analyzed. This analysis compared the cost effectiveness of SO_2 control for mixed fuel-fired steam generating units without emission credits and the cost effectiveness of these same units with emission credits. In addition, the incremental cost effectiveness of SO_2 control associated with not providing emission credits for these systems was examined.

Fuel pricing data are available only for low sulfur fuels with specific sulfur contents. Thus, in order to use available fuel pricing data, this analysis assumed an emission credit for coal/nonsulfur-bearing fuel mixtures of:

(1) 400 percent for 20 percent coal/80 percent nonsulfur-bearing fuel mixtures,
(2) 140 percent for 50 percent coal/50 percent nonsulfur-bearing fuel mixtures, and
(3) 75 percent for 80 percent coal/20 percent nonsulfur-bearing fuel mixtures.

Similarly, for oil/nonsulfur-bearing fuel mixtures the following emission credits were examined:

(1) 400 percent for 20 percent oil/80 percent nonsulfur-bearing fuel mixtures,
(2) 100 percent for 50 percent oil/50 percent nonsulfur-bearing fuel mixtures, and
(3) 100 percent for 80 percent oil/20 percent nonsulfur-bearing fuel mixtures.

TABLE 15. IMPACT OF EMISSION CREDITS ON SO_2 EMISSION LIMITS AND PERCENT REDUCTION REQUIREMENTS

Fuel Mixture (Percent)	SO_2 Emission Limit[a] Coal	SO_2 Emission Limit[a] Oil	Percent Reduction Requirement[b]
20 Fossil/80 Nonsulfur-bearing fuel	6.0	4.0	50
50 Fossil/50 Nonsulfur-bearing fuel	2.4	1.6	80
80 Fossil/20 Nonsulfur-bearing fuel	1.5	1.0	87.5

[a] SO_2 emission limit in lb SO_2/million Btu assuming an emission limit of 1.2 lb SO_2/million Btu for a coal-fired steam generating unit and 0.8 lb SO_2/million Btu for an oil-fired steam generating unit.

[b] Percent reduction requirement assuming a percent reduction requirement of 90 percent for a coal-fired or oil-fired steam generating unit.

For standards requiring a percent reduction in SO_2 emissions, the emission credits examined were:

(1) 400 percent for 20 percent fossil fuel (coal or oil)/80 percent nonsulfur-bearing fuel mixtures (i.e., 50 percent SO_2 reduction),
(2) 100 percent for 50 percent fossil fuel/50 percent nonsulfur-bearing fuel mixtures (i.e., 80 percent SO_2 reduction), and
(3) 25 percent for 80 percent fossil fuel/20 percent nonsulfur-bearing fuel mixtures (i.e., 87.5 percent SO_2 reduction).

Table 16 presents the cost and cost effectiveness of SO_2 control for a 400 million Btu/hour mixed fuel-fired steam generating unit firing coal as the fossil fuel with an emission credit. The costs and cost effectiveness for this steam generating unit size were selected for analysis and discussion because (1) the unit size is generally representative of mixed fuel-fired units (with 15 of a total 35 projected new units in this size range), and (2) new units in this size range are projected to fire the full range of fossil/nonsulfur-bearing fuel mixtures. Thus, trends in costs and cost effectiveness as a function of fuel mixture will be illustrated. In addition to the analysis of 400 million Btu/hour mixed fuel-fired steam generating units, a "worst case" analysis is presented at the end of this section for a 150 million Btu/hour steam generating unit firing a 20 percent fossil/80 percent nonsulfur-bearing fuel mixture in Region I.

As shown in Table 16, for a 400 million Btu/hour unit with an emission credit, standards based on the use of low sulfur coal would result in no reduction in SO_2 emissions in Region X. Similarly, standards based on the use of low sulfur coal would result in no reduction in SO_2 emissions for mixed fuel-fired steam generating units firing a 20 percent coal/80 percent nonsulfur-bearing fuel mixture in Regions I and IV.

Table 17 shows the incremental cost effectiveness of not providing an emission credit for coal/nonsulfur-bearing mixed fuel-fired steam generating units. The incremental cost effectiveness of the additional SO_2 emission

TABLE 16. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR A MIXED FUEL-FIRED STEAM GENERATING UNIT FIRING COAL WITH AN EMISSION CREDIT[a]

Unit Size/ Control Alternative	20 Percent Coal/80 Percent Nonsulfur-Bearing Fuel					50 Percent Coal/50 Percent Nonsulfur-Bearing Fuel					80 Percent Coal/20 Percent Nonsulfur-Bearing Fuel				
	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Coal Type	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Region I															
Regulatory Baseline (2.5 lb/Million Btu)	G-Bit	7,985	872	-	-	G-Bit	10,331	2,181	-	-	F-Bit	13,148	2,397	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	G-Bit	7,985	872	0	-	F-Bit	10,647	1,498	463	-	E-Bit	13,463	1,766	499	-
Percent Reduction (FGD)	G/50%	8,631	419	1,426	1,426	G/80%	11,384	393	589	667	G/87.5%	14,098	366	468	453
Region IV															
Regulatory Baseline (2.5 lb/Million Btu)	H-Bit	7,759	1,165	-	-	G-Bit	9,914	2,181	-	-	F-Bit	12,159	2,397	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	H-Bit	7,759	1,165	0	-	F-Bit	9,999	1,498	124	-	E-Bit	12,294	1,766	214	-
Percent Reduction (FGD)	H/50%	8,465	559	1,165	1,165	H/80%	10,941	524	620	967	H/87.5%	13,504	489	705	948
Region X															
Regulatory Baseline (2.5 lb/Million Btu)	E-Sub	7,658	442	-	-	E-Sub	9,374	1,104	-	-	E-Sub	11,015	1,766	-	-
Low Sulfur Coal (1.2 lb/Million Btu)	E-Sub	7,658	442	0	-	E-Sub	9,374	1,104	0	-	E-Sub	11,015	1,766	0	-
Percent Reduction (FGD)	E/50%	8,210	212	2,400	2,400	E/80%	10,203	199	916	916	E/87.5%	12,106	185	690	690

[a] 400 million Btu/hr mixed fuel-fired steam generating unit

[b] Based on a capacity factor of 0.6.

[c] Compared to Regulatory Baseline

[d] Compared to less stringent alternative.

TABLE 17. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING AN EMISSION CREDIT FOR MIXED FUEL-FIRED STEAM GENERATING UNITS[a]

	REGION I			REGION IV			REGION X		
	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Coal Standard									
20% Coal/80% Nonsulfur-Bearing Fuel									
With Emission Credit	7,985	872	-	7,759	1,165	-	7,658	442	-
Without Emission Credit	8,238	200	376	7,999	200	249	7,898	200	992
50% Coal/50% Nonsulfur-Bearing Fuel									
With Emission Credit	10,647	1,498	-	9,999	1,498	-	9,374	1,104	-
Without Emission Credit	10,963	499	316	10,325	499	326	9,978	499	998
80% Coal/20% Nonsulfur-Bearing Fuel									
With Emission Credit	13,463	1,766	-	12,294	1,766	-	11,015	1,766	-
Without Emission Credit	13,648	799	191	12,678	799	397	11,982	799	1,000
Percent Reduction Requirement Standard									
20% Coal/80% Nonsulfur-Bearing Fuel									
With Emission Credit	8,631	419	-	8,465	559	-	8,210	212	-
Without Emission Credit	8,741	70	315	8,601	93	292	8,304	35	531
50% Coal/50% Nonsulfur-Bearing Fuel									
With Emission Credit	11,384	393	-	10,941	524	-	10,203	199	-
Without Emission Credit	11,447	175	289	11,018	233	265	10,271	88	613
80% Coal/20% Nonsulfur-Bearing Fuel									
With Emission Credit	14,098	366	-	13,504	489	-	12,106	185	-
Without Emission Credit	14,121	279	264	13,541	373	319	12,153	141	1,068

[a]400 million Btu/hr mixed fuel-fired steam generating unit.

reductions achieved by not providing an emission credit ranges from $191/ton to $397/ton in Regions I and IV. There is little difference in this incremental cost effectiveness of SO_2 control whether standards are based on the use of low sulfur fuel or require a percent reduction in SO_2 emissions.

The incremental cost effectiveness is significantly higher in Region X than in Regions I and IV. Generally, it is in the range of $1,000/ton under a standard based on the use of low sulfur coal, and ranges from $531/ton to $1,068/ton under a standard requiring a percent reduction in SO_2 emissions. As discussed in Section 3.0, this is primarily the result of the lower emission reductions that exist between a medium and low sulfur coal in Region X compared to emission reductions between a high and low sulfur coal in Regions I and IV.

Table 18 presents the cost and cost effectiveness of SO_2 control for a 400 million Btu/hour mixed fuel-fired steam generating unit firing oil as the fossil fuel with an emission credit. As noted above for mixed fuel-fired steam generating units firing coal, with an emission credit, a standard based on the use of low sulfur fuel achieves no reduction in SO_2 emissions for a mixed fuel-fired steam generating unit firing a 20 percent oil/80 percent nonsulfur-bearing fuel mixture.

Table 19 presents the incremental cost effectiveness of not providing an emission credit for oil/nonsulfur-bearing mixed fuel-fired steam generating units. The incremental cost effectiveness of the additional SO_2 emission reduction achieved by not providing an emission credit ranges from $626/ton for a fuel mixture of 20 percent oil/80 percent nonsulfur-bearing fuel to $926/ton for the fuel mixtures of 50 percent oil/50 percent nonsulfur-bearing fuel and 80 percent oil/20 percent nonsulfur-bearing fuel under a standard based on the use of low sulfur oil.

With an emission credit, a mixed fuel-fired steam generating unit firing a fuel mixture of 20 percent oil/80 percent nonsulfur-bearing fuel fires a high sulfur oil. A mixed fuel-fired steam generating unit firing a fuel mixture of 50 percent oil/50 percent nonsulfur-bearing fuel or 80 percent oil/20 percent nonsulfur-bearing fuel, however, fires a medium

TABLE 18. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR A MIXED FUEL-FIRED STEAM GENERATING UNIT FIRING OIL WITH AN EMISSION CREDIT

Unit Size/ Control Alternative	20 Percent Oil/80 Percent Nonsulfur-Bearing Fuel					50 Percent Oil/50 Percent Nonsulfur-Bearing Fuel					80 Percent Oil/20 Percent Nonsulfur-Bearing Fuel				
	Oil Type[a] (lb SO_2/ 10^6 Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Oil Type[a] (lb SO_2/ 10^6 Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)	Oil Type[a] (lb SO_2/ 10^6 Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
REGION I															
Q = 400 Million Btu/hr															
Regulatory Baseline (3.0 lb/Million Btu)	3.0	8,353	631	-	-	3.0	11,687	1,577	-	-	3.0	14,986	2,523	-	-
Low Sulfur Oil (0.8 lb/Million Btu)	3.0	8,353	631	0	0	1.6	12,037	840	475	475	1.6	15,540	1,346	471	471
Percent Reduction (FGD)	3.0/50%	8,866	303	1,564	1,564	3.0/80%	12,491	284	622	817	3.0/87.5%	16,063	265	477	484

[a]400 million Btu/hr mixed fuel-fired steam generating unit.

[b]Average uncontrolled SO_2 emissions.

[c]Assumes a capacity factor of 0.6.

[d]Compared to regulatory baseline.

TABLE 19. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING AN EMISSION CREDIT FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING OIL AS THE FOSSIL FUEL[a]

	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)
<u>Low Sulfur Oil</u>			
20% Oil/80% Nonsulfur-Bearing Fuel			
With Emission Credit	8,353	631	-
Without Emission Credit	8,643	168	626
50% Oil/50% Nonsulfur-Bearing Fuel			
With Emission Credit	12,037	840	-
Without Emission Credit	12,426	420	926
80% Oil/20% Nonsulfur-Bearing Fuel			
With Emission Credit	15,540	1,346	-
Without Emission Credit	16,162	673	924
<u>Percent Reduction Requirement</u>			
20% Oil/80% Nonsulfur-Bearing Fuel			
With Emission Credit	8,866	303	-
Without Emission Credit	8,960	50	372
50% Oil/50% Nonsulfur-Bearing Fuel			
With Emission Credit	12,491	284	-
Without Emission Credit	12,539	126	304
80% Oil/20% Nonsulfur-Bearing Fuel			
With Emission Credit	16,063	265	-
Without Emission Credit	16,070	202	111

[a]400 million Btu/hr mixed fuel-fired steam generating unit.

sulfur oil. Without an emission credit, a mixed fuel-fired steam generating unit fires a low sulfur oil regardless of the fuel mixture.

Consequently, the incremental cost effectiveness for mixed fuel-fired steam generating units firing a 20 percent oil/80 percent nonsulfur-bearing fuel mixture under a standard based on the use of low sulfur oil, with and without an emission credit, is the difference between firing a high sulfur oil versus a low sulfur oil. For the other fuel mixtures examined, it is the difference between firing a medium sulfur oil versus a low sulfur oil. As a result, the incremental cost effectiveness of SO_2 control associated with not providing an emission credit is higher for fuel mixtures of 50 percent oil/50 percent nonsulfur-bearing fuel and 80 percent oil/20 percent nonsulfur-bearing fuel than it is for a fuel mixture of 20 percent oil/80 percent nonsulfur-bearing fuel.

As also shown in Table 19, the incremental cost effectiveness of SO_2 control resulting from the additional emission reduction associated with not providing an emission credit under a standard requiring a percent reduction in SO_2 emissions is quite low. It is generally less than $372/ton.

This incremental cost effectiveness is lower than that cited above under standards based on the use of low sulfur oil because of the "economies of scale" associated with FGD systems. With or without an emission credit, an FGD system must be installed to reduce SO_2 emissions. The only difference is that with an emission credit, the system is operated at a lower level of performance than without an emission credit. As a result, the additional SO_2 emission reduction achieved by operating the system at a high level of performance, as required without an emission credit, is very cost effective.

As discussed above, the costs and cost effectiveness analysis for a 400 million Btu/hour mixed fuel-fired unit is considered representative of mixed fuel-fired steam generating units in general and illustrates trends which are a function of fuel mixture and regional location. Costs and cost effectiveness of SO_2 control for a 150 million Btu/hour mixed fuel-fired steam generating unit with an emission credit firing a 20 percent coal/80 percent nonsulfur-bearing fuel mixture in Region X and a 20 percent oil/80 percent nonsulfur-bearing fuel mixture in Region I are presented below. This represents a "worst case" comparison in the sense that this combination of relatively small mixed fuel-fired steam generating unit and high percentage of nonsulfur-bearing fuel in the mixture results in the largest emission credits and the highest cost effectiveness of SO_2 control. Other cases involving either larger mixed fuel-fired steam generating units or a higher fossil fuel content in the fuel mixture result in lower emission credits and a lower cost effectiveness of SO_2 control. The results for Region X are also presented for a mixed fuel-fired steam generating unit firing coal because, of the three regions examined where mixed fuel-fired steam generating units are expected to be constructed in significant numbers, the coal prices in Region X result in the highest cost effectiveness of SO_2 control.

Table 20 presents the cost and cost effectiveness of SO_2 control for a 150 million Btu/hour mixed fuel-fired steam generating unit firing 20 percent coal and 80 percent nonsulfur-bearing fuel with an emission credit. This table shows that with an emission credit, standards based on the use of low sulfur coal would result in no reduction in SO_2 emissions. Thus, the average cost effectiveness of SO_2 control for standards based on the use of low sulfur coal is $0/ton. The average cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions is $3,895/ton. The incremental cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions over standards based on low sulfur coal is also $3,895/ton because the fuel fired under the regulatory baseline and under standards based on the use of low sulfur coal are the same.

Table 21 shows the incremental cost effectiveness of not providing an emission credit for mixed fuel-fired steam generating units. The incremental cost effectiveness of not providing an emission credit for a standard based on the use of low sulfur coal is $989/ton. Similarly, the incremental cost effectiveness of not providing emission credits for a standard requiring a percent reduction in SO_2 emissions is $328/ton.

Table 22 presents the cost and cost effectiveness of SO_2 control for mixed fuel-fired steam generating units firing oil as the fossil fuel with

TABLE 20. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR A MIXED FUEL-FIRED STEAM GENERATING UNIT FIRING COAL IN REGION X WITH AN EMISSION CREDIT[a]

Steam Generating Unit/Control Alternative	Fuel Type	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Regulatory Baseline (2.5 lb/million Btu)	E-Sub	3,587	166	-	-
Low Sulfur Coal (1.2 lb/million Btu)	E-Sub	3,587	166	0	-
Percent Reduction (50 Percent SO_2 removal)	E-Sub	3,922	80	3,895	3,895

[a]150 million Btu/hour mixed fuel-fired steam generating unit firing a 20 percent coal/80 percent nonsulfur-bearing fuel mixture.

[b]Based on a capacity factor of 0.6.

[c]Compared to the Regulatory Baseline.

[d]Compared to the less stringent alternative.

TABLE 21. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING AN EMISSION CREDIT FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING COAL IN REGION X[a]

	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Fuel			
With Emission Credit	3,587	166	-
Without Emission Credit	3,677	75	989
Percent Reduction Requirement			
With Emission Credit	3,922	80	-
Without Emission Credit	3,944	13	328

[a]150 million Btu/hour mixed fuel-fired steam generating unit firing a 20 percent coal/80 percent nonsulfur-bearing fuel mixture.

TABLE 22. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR A MIXED FUEL-FIRED STEAM GENERATING UNIT FIRING OIL IN REGION X WITH AN EMISSION CREDIT[a]

Steam Generating Unit/Control Alternative	Fuel Type (lb SO_2/million Btu)	Annualized Costs ($1,000/yr)	Annual Emissions[b] (tons/yr)	Average Cost Effectiveness[c] ($/ton)	Incremental Cost Effectiveness[d] ($/ton)
Regulatory Baseline (3.0 lb/million Btu)	3.0	3,713	237	-	-
Low Sulfur Oil (0.8 lb/million Btu)	3.0	3,713	237	0	-
Percent Reduction (50 Percent SO_2 removal)	3.0	4,002	114	2,350	2,350

[a]150 million Btu/hour mixed fuel-fired steam generating unit firing a 20 percent coal/80 percent nonsulfur-bearing fuel mixture.

[b]Based on a capacity factor of 0.6.

[c]Compared to the Regulatory Baseline.

[d]Compared to the less stringent alternative.

an emission credit. As explained earlier, when an emission credit is granted, a standard based on the use of low sulfur oil results in no reduction in SO_2 emissions. Thus, the average cost effectiveness of a standard based on the use of low sulfur oil is $0/ton. The average cost effectiveness of a standard requiring a percent reduction in SO_2 emissions is $2,350/ton. The incremental cost effectiveness of a standard requiring a percent reduction in SO_2 emissions over a standard based on the use of low sulfur oil is $2,350/ton.

Table 23 shows the incremental cost effectiveness of not providing an emission credit for mixed fuel-fired steam generating units firing oil as the fossil fuel. The incremental cost effectiveness of not providing emission credits is $621/ton for standards based on the use of low sulfur oil and $411/ton for standards requiring a percent reduction in SO_2 emissions.

TABLE 23. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING AN EMISSION CREDIT FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING OIL AS THE FOSSIL FUEL[a]

	Annualized Costs ($1,000/yr)	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Oil			
With Emission Credit	3,713	237	-
Without Emission Credit	3,821	63	621
Percent Reduction Requirement			
With Emission Credit	4,002	114	-
Without Emission Credit	4,041	19	411

[a]150 million Btu/hour mixed fuel-fired steam generating unit firing a 20 percent oil and 80 percent nonsulfur-bearing fuel mixture.

6.0 REFERENCES

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3. U.S. Environmental Protection Agency. Nonfossil Fuel Fired Industrial Boilers - Background Information. Research Triangle Park, NC. Publication No. 450/3-82-007. March 1982. pp. 9-28 - 9-32.

4. U.S. Environmental Protection Agency. Industrial Boiler SO_2 Cost Report. Research Triangle Park, NC. Publication No. 450/3-85-011. November 1984. p. 3-4.

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APPENDIX A

COST DEVELOPMENT FOR MIXED FUEL-FIRED STEAM GENERATING UNITS

COST DEVELOPMENT FOR MIXED FUEL-FIRED STEAM GENERATING UNITS

A. Fuel Characteristics

- Wood Characteristics

$H = 4{,}560$ Btu/lb
$\% S = 0.02$
$\% A = 1.0$

- Coal Characteristics

Depends on which coal is fired.

- Mixture Characteristics

Calculated on a heat input basis

$$\text{Wood Feed Rate (lb/hr)} = \frac{Q\ (\%\ \text{Wood})}{H_{wood}}$$

where Q = Total Heat Input (10^6 Btu/hr)

H = Heat Value (Btu/lb)

$$\text{Coal Feed Rate (lb/hr)} = \frac{Q\ (\%\ \text{Coal})}{H_{coal}}$$

Total Fuel Feed Rate (lb/hr) = Wood Feed Rate + Coal Feed Rate.

- Heating Value of Mixture

$$H_{mix} \text{ (Btu/lb)} = \frac{(\text{Wood Feed Rate})(H_{wood}) + (\text{Coal Feed Rate})(H_{coal})}{\text{Total Fuel Feed Rate (lb/hr)}}$$

- Sulfur Content of Mixture

$$S_{mix} \text{ (\%)} = \frac{(\text{Wood Feed Rate})(S_{wood}) + (\text{Coal Feed Rate})(S_{coal})}{\text{Total Fuel Feed Rate (lb/hr)}}$$

where S = Sulfur Content (%)

- Ash Content of Mixture

$$A_{mix} \text{ (\%)} = \frac{(\text{Wood Feed Rate})(A_{wood}) + (\text{Coal Feed Rate})(A_{coal})}{\text{Total Fuel Feed Rate (lb/hr)}}$$

where A = Ash Content (%)

B. Flue Gas Flowrate

$$FLW_{coal} \text{ (ACFM)} = \text{Exp } [8.14 \times 10^{-5} H_{coal}] \times 1.84 \times 10^{6} Q/H_{coal}$$

FLW_{wood}[a] (ACFM) = 73,500 acfm @ 150 million Btu/hr
196,000 acfm @ 400 million Btu/hr
392,000 acfm @ 800 million Btu/hr

$$FLW_{mix} \text{ (ACFM)} = (\text{\% Wood})(FLW_{wood}) + (\text{\% Coal})(FLW_{coal})$$

where % Wood = percent of total heat input supplied by wood.

% Coal = percent of total heat input supplied by coal.

C. Capital Costs

- Steam Generating Unit

Calculated based on information found in Reference 6. All steam generating units are spreader stokers.

- Particulate Matter Control

Fabric filter for coal/nonfossil mixture. Venturi scrubber for oil/nonfossil mixture. Costs for PM control based on algorithms presented in Reference 4, Appendix A. These costs are based on the fuel mixture characteristics.

- SO_2 Controls

Sodium scrubbing used for coal and oil/nonfossil mixtures. Costs for SO_2 control based on algorithms presented in Reference 4, Appendix A. These costs reflect the flexibility to achieve 90 percent removal for a fully fired coal or oil steam generating unit.

D. Operating and Maintenance Costs

- Steam Generating Unit

Based on information found in Reference 6. Solid waste costs calculated from spreader stoker algorithm in Appendix A of Reference 4.

- Particulate Matter Control

Fabric filter and venturi scrubber costs calculated from algorithms in Appendix A of Reference 4.

- SO_2 Control

  Sodium scrubbing costs calculated from algorithms in Appendix A of Reference 4.

E. Annualized Costs

- Calculated as shown in Table 2-8 of Reference 4.

F. After Tax Costs

- Table A-1 presents the after tax fuel prices used in this analysis. The after tax costs were calculated as explained in Reference 7.

G. Uncontrolled Emissions

- For coal/nonfossil mixtures use mixture characteristics in AP-42 equation for coal.

- For oil/nonfossil mixtures

  $$\text{Emissions} = (\%\ \text{Wood})(\text{AP-42})_{\text{wood}} + (\%\ \text{Oil})(\text{AP-42})_{\text{oil}}$$

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[a]Taken from Reference 3, p. 8-8.

TABLE A-1. AFTER-TAX NET PRESENT VALUES OF INDUSTRIAL FUEL PRICES[a] ($/MILLION BTU)

Fuel Type	Region I	Region IV	Region X
Natural Gas			
High Coal Penetration	25.45	25.68	22.77
Low Coal Penetration	22.59	23.10	21.56
Residual Oil			
High Coal Penetration			
3.0 lb $SO_2/10^6$ Btu	23.93	23.82	22.18
1.6 lb $SO_2/10^6$ Btu	25.59	25.49	23.85
0.8 lb $SO_2/10^6$ Btu	27.52	27.42	25.94
0.3 lb $SO_2/10^6$ Btu	29.36	29.35	27.71
Low Coal Penetration			
3.0 lb $SO_2/10^6$ Btu	18.27	18.15	16.58
1.6 lb $SO_2/10^6$ Btu	19.49	19.38	17.82
0.8 lb $SO_2/10^6$ Btu	20.92	20.80	19.34
0.3 lb $SO_2/10^6$ Btu	22.34	22.21	20.61
Coal			
Bituminous			
B	14.00	11.99	11.79
D	13.86	11.24	11.10
E	13.60	11.16	10.51
F	12.85	10.83	-
G	11.90	10.43	-
H	12.18	9.78	-
Subbituminous			
B	-	-	9.87
D	-	-	9.64
E	-	-	7.78

[a]Taken from Reference 8.

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(Please read Instructions on the reverse before completing)

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16. ABSTRACT

This document presents an analysis of the costs and cost effectiveness of SO_2 control for steam generating units firing mixtures of sulfur-bearing fossil fuels (coal or oil) with nonsulfur-bearing fuels (wood, solid waste, natural gas, etc.). The incremental cost effectiveness of an alternative control level requiring a percent reduction in SO_2 emissions over an alternative control level based on the use of low sulfur fuel was examined for various boiler sizes, regional locations, and fuel mixtures. The incremental cost effectiveness increases as decreasing amounts of coal or oil are burned in relation to nonsulfur-bearing fuels.

The report also examines the costs associated with allowing versus not allowing emission credits based on the dilution of the sulfur-bearing fuel heat input with that from nonsulfur-bearing fuels.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air pollution Pollution control Standards of performance Fossil fuel-fired industrial boilers Mixed fuel-fired industrial boilers Steam generating units	Fossil fuel-fired industrial boilers Air pollution control Mixed fuel-fired industrial boilers	13 B

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