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Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input

NSPS

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Summary of Regulatory Analysis for New Source Performance Standards: Industrial-Commercial-Institutional Steam Generating Units of Greater than 100 Million Btu/hr Heat Input

Emission Standards and Engineering Division

U. S. ENVIRONMENTAL PROTECTION AGENCY
Office of Air and Radiation
Office of Air Quality Planning and Standards
Research Triangle Park, NC 27711

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1.0 INTRODUCTION

This document summarizes the results of various analyses performed in support of proposed new source performance standards limiting emissions of sulfur dioxide and particulate matter from industrial-commercial-institutional steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour). It is intended to serve as an overview of the analyses and regulatory alternatives considered in developing the proposed standards and, as such, includes only the highlights of the many regulatory, technical, and economic analyses considered during the decision-making process. These analyses are supported and discussed in detail by various other documents and reports contained in the docket for this rulemaking (Docket No. A-83-27). This includes, but is not limited to, the following:

1. Fossil Fuel-Fired Industrial Boilers - Background Information, Volumes 1 and 2 (EPA-450/3-82-006a and b), March 1982;

2. Nonfossil Fuel-fired Industrial Boilers - Background Information (EPA-450/3-82-007), March 1982;

3. Industrial Boiler SO_2 Technology Update Report (EPA-450/3-85-009), July 1984;

4. Fluidized Bed Combustion: Effectiveness as an SO_2 Control Technology for Industrial Boilers (EPA-450/3-85-010), September 1984;

5. Industrial Boiler SO_2 Cost Report (EPA-450/3-85-011), November 1984;

6. Projected Impacts of Alternative Sulfur Dioxide New Source Performance Standards for Industrial Fossil Fuel-Fired Boilers, March 1985;

7. An Analysis of the Costs and Cost Effectiveness of SO_2 Control for Mixed Fuel-Fired Steam Generating Units (EPA-450/3-86-001), January 1986;

8. An Analysis of the Costs and Cost Effectiveness of Allowing SO_2 Emission Credits for Cogeneration Systems (EPA-450/3-85-030), December 1985.

2.0 SELECTION OF SOURCE CATEGORY

On August 21, 1979, a priority list for development of additional new source performance standards (NSPS) was published in accordance with Sections 111(b)(1)(A) and 111(f)(1) of the Clean Air Act. This list identified 59 major stationary source categories that were judged to contribute significantly to air pollution that could reasonably be expected to endanger public health or welfare. Fossil fuel-fired industrial steam generating units ranked eleventh on this priority list of sources for which new source performance standards would be established in the future.

Of the 10 sources ranked above fossil fuel-fired industrial steam generating units on the priority list, nine were major sources of volatile organic compound (VOC) emissions. Because there are many areas which have not attained the national ambient air quality standard for ozone, major sources of VOC emissions were accorded a very high priority. The remaining source category ranked above fossil fuel-fired industrial steam generating units was stationary internal combustion engines, a major source of nitrogen oxides (NO_x) emissions. Fossil fuel-fired industrial steam generating units were the highest ranked source of particulate matter and sulfur dioxide (SO_2) emissions, and the second highest ranked source of NO_x emissions when the priority list of source categories not previously regulated by NSPS was published.

Wood and solid waste are widely used as fuel in industrial steam generating units. As a result, industrial-commercial-institutional steam generating units firing these fuels could also be significant contributors to future air pollution. In addition, large commercial and institutional steam generating units have essentially the same design, fuel capability, and emissions potential as industrial steam generating units. Consequently, on June 19, 1984, an amendment to the priority list was proposed that would expand the source category of industrial fossil fuel-fired steam generating units to cover all steam generating units, including both fossil fuel-fired and nonfossil fuel-fired steam generating units, as well as steam generating units used in commercial and institutional applications (49 FR 25156, June 19, 1984). Consistent with this proposed amendment of the priority list, the source category for the proposed standards includes both fossil fuel- and nonfossil fuel-fired industrial, commercial and institutional steam generating units.

Fossil and nonfossil fuel-fired steam generating units are significant sources of emissions of three major pollutants: particulate matter, SO_2, and NO_x. The expected construction of new coal-, oil-, and fossil/nonfossil fuel-fired steam generating units as a result of plant expansions and replacements of existing steam generating units is expected to result in a growth in emissions from this source category. A number of these new facilities will fire coal and high sulfur oil. Combustion of wood and solid waste in combination with coal or oil is also projected to increase due to the lower cost of these nonfossil fuels. These developments could result in significant increases in SO_2 emissions if standards of performance are not established for new industrial-commercial-institutional steam generating units.

National ambient air quality standards have been established for SO_2 because of its known adverse effects on public health and welfare. Impacts of this pollutant have been documented in a criteria document prepared under Section 108 of the Clean Air Act. These effects are a major basis for concluding that emissions from industrial-commercial-institutional steam generating units constitute a potential danger to public health and welfare. Also significant is the fact that many new industrial-commercial-institutional steam generating units will be located in urban areas where a large population will be exposed to the emissions.

3.0 SELECTION OF POLLUTANTS, FUELS, AND AFFECTED FACILITIES

Particulate matter emissions from the combustion of oil, and sulfur dioxide (SO_2) emissions from the combustion of oil, coal and mixed fuels (i.e., combustion of mixtures of fossil fuels or fossil and nonfossil fuels) would be the pollutants regulated under the proposed standards. New source performance standards have already been proposed that would limit particulate matter emissions from industrial-commercial-institutional steam generating units firing coal, wood, or solid waste and NO_x emissions from steam generating units firing mixtures of fossil or fossil and nonfossil fuels (49 FR 25102, June 19, 1984).

The potential impacts associated with this "phased" approach to rulemaking were considered prior to proposing standards for particulate matter and NO_x. The standards being proposed today are not retroactive and affect only new steam generating units built after this date. No potential problems have been identified that might result from this phased approach to rulemaking and no unreasonable impacts are anticipated to occur.

The proposed standards would limit emissions of SO_2 from steam generating units firing oil, coal, and fuel mixtures containing any of these fuels and emissions of particulate matter from oil-fired steam generating units. The proposed standards would cover industrial-commercial-institutional steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour). Analyses of the projected new steam generating unit population indicate that nearly all new steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity will be industrial steam generating units, with only a few commercial and institutional steam generating units in this size range. The steam generating unit size limit of 29 MW (100 million Btu/hour) heat input capacity would, therefore, include only the largest commercial and institutional steam generating units and would concentrate the scope of the proposed standards on industrial steam generating units. Utility steam generating units larger than 73 MW (250 million Btu/hour) heat input capacity remain subject to Subpart Da. Utility auxiliary steam generating units smaller than 73 MW (250 million Btu/hour) heat input capacity but larger than 29 MW (100 million Btu/hour) heat input capacity would be subject to the proposed standards.

Development of new source performance standards limiting emissions of sulfur oxides, nitrogen oxides, and particulate matter from steam generating units with heat input capacities of 29 MW (100 million Btu/hour) or less is currently underway. The type of unit used, the physical design characteristics of these units, the cost impacts of emission control systems on steam production costs, and the application of steam are often different for smaller steam generating units than for larger steam generating units. Because these factors have been found to be materially different, separate study of smaller steam generating units is appropriate. This will assure that an adequate evaluation is conducted of the technical and economic factors associated with applying emission controls to smaller steam generating units.

4.0 SELECTION OF DEMONSTRATED EMISSION CONTROL TECHNOLOGIES

4.1 SULFUR DIOXIDE EMISSIONS FROM COAL AND OIL COMBUSTION

Sulfur dioxide (SO_2) is formed in industrial-commercial-institutional steam generating units by the oxidation of sulfur contained in the fuels. Uncontrolled emissions of SO_2 depend primarily on the sulfur content of the fuel. The type of firing mechanism, or the type of industrial-commercial-institutional steam generating unit, does not affect SO_2 emissions. However, variations in fuel properties other than sulfur content also affect uncontrolled SO_2 emissions. The concentration of alkaline species in the fuel ash, for example, affects the amount of sulfur retained in the fly ash and the bottom ash formed during combustion. Oil, which has low ash and low alkalinity, retains little, if any, fuel sulfur in the fly ash and bottom ash. On the other hand, western subbituminous coals, which have a highly alkaline ash, can retain up to 20 percent of the sulfur in fly ash and bottom ash.

Approaches for reducing SO_2 emissions from industrial-commercial-institutional steam generating units can be divided into three categories: low sulfur fuels, combustion modification techniques, and post-combustion or flue gas desulfurization (FGD) techniques. Combustion of low sulfur fuel reduces SO_2 emissions by reducing the amount of sulfur available for SO_2 formation during combustion. Combustion modification reduces SO_2 emissions by reacting SO_2 with an alkaline material (usually limestone) within the combustion chamber as the SO_2 is formed. Flue gas desulfurization reduces SO_2 emissions by "scrubbing" or "washing" the combustion gases downstream from the steam generating unit with aqueous solutions or slurries of alkaline reagents.

Low sulfur fuels may be produced from high sulfur fuels or they may be obtained from naturally occurring low sulfur coal or low sulfur oil deposits. Methods of producing low sulfur fuels from high sulfur fuels include coal gasification, coal liquefaction, physical coal cleaning, and oil hydrodesulfurization.

Coal gasification produces a low sulfur fuel by converting coal to a gas, which can be cleaned and then fired in a steam generating unit. In coal gasification, pretreated coal is reacted with a steam/air or a steam/oxygen mixture at high temperatures and pressures. The resultant gas is then treated to remove particulate matter, sulfur, and nitrogen. Part of the sulfur is removed in a gas quenching and cooling section, but most of it is removed in an acid gas removal (AGR) system. In applications where the product gas is used as a chemical plant feedstock, AGR systems have been used to reduce sulfur concentrations in the gas to one part per million or less.

Despite its potential for producing a low sulfur fuel, few coal gasifiers have been designed specifically for industrial-commercial-institutional steam generating units. These gasifiers generally do not include an AGR section in the gas treatment step. As a result, the gas produced contains only about 10 percent less sulfur than the original coal. Since conversion of coal to gas results in a 10 to 25 percent decrease in the heating value, the product gas from gasifiers without an AGR system actually has a higher sulfur content, in terms of heat content, than the original coal. In these applications, therefore, the use of coal gasification actually results in an increase in SO_2 emissions.

Coal gasification is not likely to achieve widespread application to new industrial-commercial-institutional steam generating units in the near future. These systems generally have not been economically competitive when compared with the use of natural gas. As a result, coal gasification is not considered a demonstrated control technology for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, or reconstructed industrial-commercial-institutional steam generating units.

The major processes for coal liquefaction are Solvent Refined Coal-I (SRC-I), Solvent Refined Coal-II (SRC-II), H-Coal, and the Exxon Donor Solvent (EDS) process. All of these processes involve the direct conversion of coal into liquid form through the addition of hydrogen to coal at elevated temperatures and pressures.

All of the coal liquefaction processes mentioned above reduce the concentrations of nitrogen, ash, and sulfur in the liquid fuel produced from the concentrations in the original coal. All except SRC-I produce fuels that can be substituted for petroleum-based fuels in oil-fired steam generating units. The SRC-I process produces a solid fuel that can only be used in pulverized coal-fired steam generating units.

Several pilot-scale coal liquefaction plants have been built and tested. However, to date no commercial coal liquefaction plants have been constructed, nor are any planned or under construction. In view of the long lead time associated with the design, construction, and startup of coal liquefaction plants, it seems certain that these fuels will not be available for use in industrial-commercial-institutional steam generating units in the near future. As a result, coal liquefaction is not considered a demonstrated control technology for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, or reconstructed industrial-commercial-institutional steam generating units.

Physical coal cleaning (PCC) reduces the sulfur content of coal while increasing its heat content. In a modern PCC plant, coal is subjected to size reduction and screening before it is washed, dewatered, and dried. The coal is separated from its impurities primarily during the washing phase. In this phase, the impurities separate from the coal because of the differences in specific gravities and surface properties between the "fuel-rich" organic matter and the "fuel-lean" mineral matter in the coal.

The extent of sulfur reduction in PCC depends primarily on the form of the sulfur in the coal. Sulfate sulfur, which is present in most coals in trace amounts, is usually water soluble and is readily removed by washing the coal. Organic sulfur, on the other hand, is chemically bonded to the organic carbon in the coal and cannot be removed by PCC. Pyritic sulfur, which may comprise between 30 and 70 percent of the coal sulfur content, is much denser than coal and is best removed by gravity separation. PCC can typically remove about 50 percent of the pyritic sulfur in coal. Since PCC increases the heat content of coal, the net sulfur removal on a heat content [nanograms SO_2/Joule (ng/J) or lb SO_2/million Btu] basis is typically between 20 and 40 percent.

Approximately one-third of the domestically produced bituminous and lignite coal underwent PCC in 1978. PCC is readily applicable to these two types of coal because they have relatively high pyritic sulfur contents. Subbituminous coal, on the other hand, contains little pyritic sulfur and has generally not been subjected to PCC.

Physical coal cleaning became attractive not so much for environmental reasons, but for economic reasons. PCC produces a higher grade of coal, having a higher heat content. This results in a reduction in transportation costs, ash disposal costs, and steam generating unit maintenance costs. Higher grades of coal can also improve steam generating unit efficiency and reliability.

Physical coal cleaning is considered a demonstrated emission control technology for reducing emissions of SO_2 from combustion of bituminous and lignite coals. However, this technology requires too much space and is too expensive to be employed at individual industrial-commercial-institutional steam generating units. Consequently, this technology is not employed directly by industrial-commercial-institutional steam generating units. Low sulfur coal, however, may be purchased from PCC plants supplying utility steam generating units. As a result, while the use of PCC is included in the analyses below, it is only included indirectly in the sense that, where appropriate, the cost of low sulfur coal includes the costs of PCC to produce that coal.

Hydrotreating or hydrodesulfurization (HDS) processes can substantially reduce the concentrations of sulfur, nitrogen, and ash in fuel oils. HDS processes involve contacting the oil with hydrogen over a catalyst to convert much of the chemically bonded sulfur to gaseous hydrogen sulfide (H_2S). The waste gas is then separated from the fuel and the sulfur is reclaimed as elemental sulfur or sulfuric acid.

HDS technology has been in commercial use for approximately 20 years. As of 1975, over 30 HDS processes were actively in use, and over 250 processes had been described in patent literature. Not only is HDS effective in reducing SO_2 emissions from oil combustion in steam generating units, but it also improves the performance of steam generating units by reducing the potential for corrosion and particulate matter deposit.

HDS is considered a demonstrated emission control technology for reducing emissions of SO_2 from oil combustion. As with PCC, however, HDS requires too much space and is much too costly to be employed at individual industrial-commercial-institutional steam generating units. Hydrodesulfurization is employed by petroleum refineries to produce low sulfur fuel oil. As with PCC, this technology is also included indirectly in the analyses below, in the sense that, where appropriate, the cost of low sulfur fuel oil includes the costs of HDS to produce that oil.

4.1.1 Low Sulfur Coal

Fuels may be broadly classified by any number of schemes. However, from the standpoint of SO_2 emissions, it is useful to classify fuels with respect to their sulfur content.

The coal classification scheme that has been adopted to represent coals that are combusted in steam generating units is presented in Table 4-1, with each coal type represented by a range of sulfur content. This classification scheme has its origin in classifications used by the U. S. Bureau of Mines to report available coal reserves. In a subsequent series of studies based on Bureau of Mines data, the classification scheme evolved to reflect existing coal reserves and supplies more accurately. For example, the number of classifications was reduced and the range of sulfur content for each coal type was adjusted, resulting in the classification scheme presented in Table 4-1.

The sulfur contents of the low sulfur coal types generally represent coals that can meet the existing new source performance standards (40 CFR Part 60, Subpart D) that apply to steam generating units with a heat input capacity greater than 73 MW (250 million Btu/hour). The sulfur contents of the medium sulfur coal types generally represent coals that meet SO_2 emission limits in many existing State Implementation Plans (SIP's).

TABLE 4-1. FUEL SULFUR CONTENT AND SO_2 EMISSION RATES FOR COAL AND OIL TYPES

Fuel Type	Fuel Sulfur Content	Midpoint Fuel Sulfur Content	Midpoint SO_2 Emission Rate
	ng S/J (lb S/million Btu)	ng S/J (lb S/million Btu)	ng SO_2/J (lb SO_2/million Btu)
COAL:			
Very Low Sulfur	<172.0 (<0.40)	86 (0.20)	172 (0.40)
Low Sulfur	172-232 (0.40-0.54)	202 (0.47)	404 (0.94)
Low Sulfur	232-357 (0.54-0.83)	295 (0.69)	590 (1.37)
Medium Sulfur	357-538 (0.83-1.25)	447 (1.04)	894 (2.08)
Medium Sulfur	538-718 (1.25-1.67)	628 (1.46)	1,254 (2.92)
High Sulfur	718-1,075 (1.67-2.50)	897 (2.09)	1,793 (4.17)
High Sulfur	>1,075.0 (>2.50)	1,075 (2.50)	2,150 (5.00)
OIL:			
Very Low Sulfur	65 (0.15)	65 (0.15)	129 (0.3)
Low Sulfur	172 (0.40)	172 (0.40)	344 (0.8)
Medium Sulfur	344 (0.80)	344 (0.80)	688 (1.6)
High Sulfur	645 (1.50)	645 (1.50)	1,290 (3.0)

Finally, the high sulfur coal types represent coals that must be processed or blended with lower sulfur coals to meet current SO_2 emission limits. This classification scheme can be simplified by using the midpoints of each sulfur content range to represent the sulfur content of these coal types. The midpoints for each coal type are also shown in Table 4-1.

Most of the sulfur contained in coal is converted to SO_2 during combustion. However, 5 to 20 percent of the coal sulfur is typically retained in bottom ash and fly ash. The degree of sulfur retention depends on several factors, such as the type of steam generating unit and the chemical properties of the coal, particularly the concentration of alkaline constituents. Because sulfur retention is quite variable and dependent on a number of factors, for this analysis it is assumed that 100 percent of the sulfur present in coal is converted to SO_2. Because sulfur dioxide (SO_2) has twice the mass of sulfur (S), the SO_2 emission rates presented in Table 4-1 for each coal type are double the coal sulfur content.

As shown by the emission rates in Table 4-1, low sulfur coal can be used to reduce SO_2 emissions. Combustion of low sulfur coal reduces SO_2 emissions by 30 to 50 percent compared to combustion of medium sulfur coal, and by as much as 60 to 80 percent compared to combustion of high sulfur coal.

Low sulfur coal is widely used in both industrial and utility steam generating units to reduce SO_2 emissions from coal combustion. For example, in 1982 the utility sector consumed 14,100,000 Mg (15,500,000 tons) of low sulfur coal. Low sulfur coal, therefore, is considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

4.1.2 Low Sulfur Oil

As with coal, fuel oil can be classified by sulfur content. Table 4-1 presents the oil classification scheme that has been adopted to represent oils that are combusted in industrial-commercial-institutional steam generating units. In this classification scheme, each type of oil is represented by a typical sulfur content. This classification scheme had its origin in the classifications used by the U. S. Department of Energy to report refinery production data, and in studies of fuel oil use patterns.

The classifications reflect the fact that many distillate and residual oils are produced to meet market demands created by existing SO_2 emission regulations. Accordingly, low sulfur fuel oils represent those oils that can be fired to meet the existing new source performance standards (40 CFR Part 60, Subpart D) for steam generating units with a heat input capacity greater than 73 MW (250 million Btu/hour). The sulfur content of medium sulfur fuel oils represents oils that can be combusted to comply with SO_2 emission limits included in many existing SIP's. The sulfur content of high sulfur fuel oils represents oils that comply with SO_2 emission limits included in the remaining SIP's.

Most of the sulfur contained in oil is converted to SO_2 during combustion, with only one to four percent of the sulfur typically retained in the fly ash. The degree of sulfur retention depends on several factors, including the oil type and its chemical composition, especially the concentration of metal constituents. Because sulfur retention in fly ash is relatively minimal and varies among fuel oils, 100 percent of the fuel sulfur has been assumed to be converted to SO_2. Consequently, the emission rates represented in Table 4-1 for each oil type are twice the oil sulfur content.

As shown by the emission rates in Table 4-1, low sulfur oil can be used to reduce emissions of SO_2. Combustion of low sulfur oil reduces SO_2 emissions by 50 to 80 percent compared to combustion of medium sulfur oil, and by 70 to 90 percent compared to combustion of high sulfur oil.

Low sulfur oil is widely used in industrial and utility steam generating units to reduce SO_2 emissions from oil combustion. Low sulfur oil, therefore, is considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

4.1.3 Combustion Modification

Combustion modification techniques for the control of SO_2 involve the capture of SO_2 by an alkaline species, usually limestone, within the combustion zone of the steam generating unit. The result is that the SO_2 formed during combustion reacts with the alkaline species to form sulfite and sulfate salts. These salts exit the steam generating unit with the flue gas and are removed downstream by a particulate matter control device such as a fabric filter, electrostatic precipitator, or mechanical collector. Several combustion modification techniques are currently under development, including coal/limestone pellets, limestone injection multistaged burners, and fluidized bed combustion.

Coal/limestone pellet (CLP) technology is a combustion modification technique in which pellets formed from coal and limestone are burned together in stoker coal-fired steam generating units. Coal/limestone pellets can be manufactured on-site by pellet milling, briquette production, auger extrusion, or disk production. The SO_2 formed during combustion reacts with the limestone present in the fuel pellets to form calcium sulfite and sulfate salts. A major portion of these sulfite and sulfate salts remains in the ash and is removed from the steam generating unit along with the bottom ash. The remaining sulfite and sulfate salts accompany the fly ash in the flue gas and are removed by a particulate matter control device.

The calcium-to-sulfur (Ca/S) ratio in the CLP is the primary factor affecting sulfur capture during combustion. Tests using pellets with a Ca/S ratio of seven-to-one have yielded SO_2 removal efficiencies as high as 70 percent. This technology is not being used commercially at this time, however, and future applications are expected to be limited because of the adverse effects that CLP's can have on the operation of a steam generating unit. The use of CLP's, for example, is expected to reduce the rated capacity of a steam generating unit by about 20 percent. Furthermore, the increase in bottom ash could decrease the reliability of the steam generating unit and increase its maintenance costs. Consequently, the CLP technology must be considered an emerging technology and cannot be considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

The limestone injection multistaged burner (LIMB) technology is a combustion modification technology that is capable of reducing SO_2 emissions from pulverized coal-fired steam generating units. In this process, dry, finely ground sorbent (such as dolomite) is injected into the furnace through burners or through separate injection ports installed in the furnace wall. The limestone reacts with SO_2 formed during combustion to form calcium sulfite and sulfate salts, which are entrained in the flue gas and collected along with the fly ash in a downstream particulate matter control device.

The primary factors affecting sulfur capture are the reactivity of the sorbent (as measured by surface area), the Ca/S ratio during combustion, the sorbent injection technique, and the residence time of the sorbent in that part of the steam generating unit where reaction with SO_2 can occur. Initial tests of the LIMB technology on small scale equipment have been promising, achieving more than a 70 percent reduction in SO_2 emissions when highly reactive sorbents are used.

No long-term commercial data are available, however, on the performance or economics of LIMB as applied to industrial-commercial-institutional steam generating units. LIMB, therefore, must be considered an emerging control technology and not demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

Fluidized bed combustion (FBC) is a third type of combustion modification technology. In conventional steam generating units, fuel is combusted either on a grate or in suspension and a significant portion of the heat exchange takes place outside of this combustion zone. In fluidized bed systems, fuel is combusted in a fluidized bed maintained by a stream of air blowing upwards from a distribution plate. This design permits the watertubes in which steam is generated to be submerged in the fluidized bed or combustion zone of burning fuel. Submersion of the watertubes directly into the combustion zone improves heat transfer. FBC systems can be operated at much lower temperatures to achieve the same steam quality as conventional steam generating units operating at higher temperatures. This enables FBC systems to burn lower quality fuels than are typically burned in conventional steam generating units and still generate the same steam quality. It also permits limestone to be added to the fluidized bed to capture SO_2 without impairing combustion performance.

At the combustion temperatures achieved by FBC systems, 760°C to 870°C (1,400°F to 1,600°F), limestone releases carbon dioxide and is transformed into lime. Lime then reacts with SO_2 and excess oxygen to form anhydrous calcium sulfate. The calcium sulfate, ash, and unreacted lime are removed from the system through a drain as overflow from the fluidized bed. Those solids that are entrained in the combustion gases are removed in a particulate matter control device.

Sulfur dioxide removal efficiencies depend primarily on the Ca/S ratio in the combustion zone. Sulfur dioxide removal efficiency will also be improved by recycling part of the elutriated lime and limestone, decreasing the limestone particle size, using limestone which is highly reactive, using coals with high ash alkalinity, and increasing the amount of time that lime and SO_2 are allowed to react.

The SO_2 removal efficiency increases as the Ca/S ratio increases. The recycle of elutriated bed material can have a significant effect on SO_2 removal at a given Ca/S ratio because the recycled material typically contains unreacted sorbent. Increasing the solids recycle ratio increases SO_2 removal efficiency at a given Ca/S ratio or lowers the Ca/S ratio necessary to achieve a given percent SO_2 reduction. Circulating bed FBC units, which feature a recirculating entrained bed, are an extension of the solids recycle approach. Use of a coal that has a highly alkaline ash has the effect of reducing the amount of limestone necessary to maintain a constant Ca/S ratio or raising the Ca/S ratio if the amount of limestone is held constant.

Increasing the gas-phase residence time (the ratio of expanded bed height to the superficial gas velocity) improves SO_2 removal efficiency. This is because the time available for calcination and sulfation reactions within the bed increases. However, some coal is combusted above the bed due to elutriation of smaller coal particles. Thus, SO_2 is also formed above the bed. As calcined limestone particles are also elutriated, SO_2 removal can still occur if sufficient time for gas and sorbent contact is available. One way to increase the gas and sorbent contact time, and therefore percent SO_2 removal, is to increase the freeboard height. While this may be infeasible for retrofit applications, new FBC units could be designed with higher freeboard.

As the particle size of a given sorbent decreases, the calcium utilization increases. Thus, with the same Ca/S ratio, the SO_2 removal efficiency can be increased significantly by decreasing the sorbent particle size. However, the particles should not be sized so small that they are elutriated from the steam generating unit before adequate reaction time is achieved.

The FBC technology is well developed and widely applied throughout the world. In the United States, approximately 80 FBC systems are currently operating or scheduled to begin operation in the near future. Most of the FBC systems in the United States have been installed to recover the fuel value of process wastes which do not contain significant quantities of sulfur. About 20 existing or planned FBC systems in the United States are designed to burn coal or mixtures of coal and other fuels. Nearly all of these FBC systems use limestone for SO_2 control. Existing and planned coal-fired FBC systems encompass steam generating unit sizes of from 7 to 53 MW (25 to 180 million Btu/hour) heat input capacity and fire coals ranging in sulfur content from about 430 to 3,010 ng SO_2/J (1.0 to 7.0 lb SO_2/million Btu).

The FBC systems described above are currently achieving average SO_2 removal efficiencies ranging from 55 to 90 percent. They are capable of higher efficiencies, but in order to minimize costs, these systems are currently operated at the lowest SO_2 removal efficiencies required by existing air pollution control regulations. Emission test data have shown that, with sufficiently high Ca/S ratios, FBC units can achieve SO_2 removal efficiencies of 90 percent or more. Consequently, FBC is considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

4.1.4 Post-Combustion Technologies

Post-combustion technologies remove SO_2 from steam generating unit flue gases by "scrubbing" them with an alkaline reagent. These technologies are more commonly labeled flue gas desulfurization (FGD) technologies and can be divided into two broad groups: dry scrubbing and wet scrubbing. In dry scrubbing, SO_2 is absorbed by and reacts with an alkaline material to produce a dry particulate powder consisting of sulfite and sulfate salts that is then removed from the scrubber flue gas by a particulate matter control device. In wet scrubbing, SO_2 is absorbed by and reacts with alkaline reagents in either an aqueous solution or slurry. In sodium-based wet scrubbing systems, the sulfur is discharged as dissolved sodium sulfite and sulfate in a wastewater stream. In calcium-based wet scrubbing systems, the sulfur is discharged as a calcium sulfite and sulfate sludge.

Dry scrubbing processes include electron beam irradiation, dry alkali injection, and lime spray drying. In the electron beam irradiation process, the combustion flue gases are first cooled and humidified in a water quench tower. Ammonia is then injected into the cooled flue gas and the resulting mixture is passed through an electron beam reactor. In the reactor, the flue gas is irradiated with an electron beam that ionizes oxygen and water. The hydrogen and oxygen radicals that are formed react with SO_2 to produce sulfuric acid. The acid is then neutralized by the ammonia and water in the flue gas to form solid ammonium sulfate which is then collected in a particulate matter control device such as an electrostatic precipitator or fabric filter.

At present, there are no commercial applications of electron beam irradiation for removing SO_2 from steam generating unit flue gases. Research projects are underway in the United States and in Japan to investigate the technology's effectiveness in controlling SO_2 emissions. Since the electron beam irradiation process is in the very early stages of development, it is not considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

In the dry alkali injection process, a dry alkaline material is injected into the combustion flue gases as they leave the steam generating unit. This alkaline material is usually a naturally occurring sodium compound such as nacholite or trona ore. The sodium reacts with SO_2 to form solid sodium sulfate particles that are collected along with the fly ash in a particulate matter control device. Although both electrostatic precipitators and fabric filters have been used in dry alkali injection processes, fabric filters are preferred because of the continuation of the reaction between the SO_2 in the flue gas and the dry alkali reagent in the filter cake deposited on the fabric filter surface.

The primary factors which affect the performance of dry alkali injection systems are the amount of alkaline reagent added, the temperature at the point of injection, and the size of the alkaline reagent particles. The removal of SO_2 increases as the ratio of alkaline reagent to flue gas SO_2 increases. In limited tests, a dry alkaline injection system applied to a 22 MW electric output utility steam generating unit combusting a low sulfur coal achieved SO_2 removal efficiencies of 70 and 80 percent with nacholite, at alkaline reagent-to-flue gas sulfur ratios of approximately 0.8 and 1.1, respectively. With trona ore, the same system achieved SO_2 removal efficiencies of 70 and 90 percent at reagent-to-flue gas sulfur ratios of 1.3 and 2.4, respectively.

In addition to the tests conducted on this electric utility demonstration unit, numerous other pilot and laboratory scale studies have been conducted on dry alkali injection with similar results. Because the technology is simple in both design and operation, it is expected to be highly reliable. However, dry alkali injection has not yet been commercially applied to industrial-commercial-institutional steam generating units, primarily due to the high cost and limited availability of nacholite and trona ore. As a result, dry alkali injection is not considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

Lime spray drying is a dry scrubbing technology in which the flue gases from a steam generating unit are sprayed with a finely atomized lime slurry in a spray dryer. Although sodium carbonate can be used instead of lime, it is not currently being used in commercial applications because it is much more expensive.

In lime spray drying systems, flue gas SO_2 is absorbed by and reacts with the fine mist of slurried lime in the spray dryer to form calcium sulfite and sulfate salts. At the same time, the hot flue gas evaporates the water contained in the slurry to produce a dry powder. The powder generally has a moisture content of less than one percent. Absorption, reaction, and drying occur within the ten-second gas residence time in the spray dryer. The evaporation of water from the slurry mist cools the combustion flue gases to within 10 to 20°C (20 to 40°F) of their saturation temperatures. The flue gas from the spray dryer, along with its entrained solids (consisting of sulfite and sulfate salts, unreacted reagent, and fly ash), passes into a particulate matter collection device such as an electrostatic precipitator or fabric filter. The collected solids are then typically transported to a solid waste disposal site.

The key factors affecting the SO_2 removal efficiency of lime spray drying are reagent ratio, approach to saturation temperature, and the type of particulate matter control device used. Other factors include solids recycling and the temperature of the combustion flue gases entering the spray dryer.

The SO_2 removal efficiency increases with increasing reagent ratio (defined as the ratio of calcium-to-sulfur present in the combustion flue gases). However, recycling a portion of the solids collected by the particulate matter control device to the spray dryer can recover unreacted reagent and thus lower the lime reagent ratio required to achieve a given SO_2 removal efficiency.

The approach to saturation temperature is the difference between the actual temperature of the flue gas leaving the spray dryer and the temperature that is observed if the flue gas is cooled to the point at which it is saturated with water. Operating closer to the saturation temperature allows more lime slurry to be sprayed into the dryer and delays the drying of the lime slurry droplets, increasing the amount of SO_2 absorption and reaction. There is a practical limit, however, to how closely the spray dryer flue gas can approach the saturation temperature without condensation occurring in the downstream flue gas ducts and in the particulate matter control device. Condensation can result in caking of fabric filters and corrosion of metal surfaces. As a result, the approach to saturation temperature for lime spray drying systems typically ranges from 10 to 28°C (20 to 50°F). Operation at or near a 10°C (20°F) approach to saturation temperature is common where SO_2 removal requirements are high. It should be noted, however, that increasing the temperature of the combustion flue gases entering the spray dryer, by removing less heat from those gases in the convection section of the steam generating unit, will improve SO_2 removal efficiency by allowing more lime slurry to be sprayed into the dryer without operating any closer to the flue gas saturation temperature.

The performance of lime spray drying systems can also be affected by the type of particulate matter collection device that is used. In most commercial lime spray drying systems, fabric filters have been chosen over electrostatic precipitators. With fabric filters, the flue gas passing through the unreacted lime in the filter cake that builds up on the filter fabric reacts with the remaining SO_2 in the flue gas, increasing overall SO_2 removal. Studies have shown that SO_2 removal in the fabric filter can account for as much as 15 to 30 percent of the total SO_2 removal.

To date, 21 lime spray drying systems have been sold for application to coal-fired industrial-commercial-institutional steam generating units ranging in size from 30 to 150 MW (100 to 530 million Btu/hour) heat input capacity. The sulfur content of the coal combusted in these units ranges from 600 to 2,600 ng SO_2/J (1.5 to 6.0 lb SO_2/million Btu).

The lime spray drying systems described above are currently achieving SO_2 removal efficiencies in the range of 60 to 80 percent. They are capable of much higher efficiencies, but in order to minimize costs, these systems are currently operated at the lowest SO_2 removal efficiencies required by existing air pollution control regulations. However, most of these systems have been designed and guaranteed by their vendors to achieve a 90 percent reduction in SO_2 emissions, and short-term tests have substantiated their claims. Because lime spray drying has been operated successfully and has been shown and guaranteed to be capable of achieving high SO_2 removal efficiencies, it is considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

Wet scrubbing processes include lime, limestone, dual alkali, and sodium wet scrubbing. Wet scrubbing techniques use alkaline solutions or slurries that are more dilute than those used in dry scrubbing. In addition, wet scrubbing techniques produce a liquid waste byproduct while dry scrubbing techniques produce a dry powder or solid waste byproduct. In lime, limestone, and dual alkali systems, the liquid waste byproduct is converted to a sludge for disposal. In sodium scrubbing, the liquid waste byproduct is generally treated and discharged directly to surface waters or discharged to publicly owned treatment works for disposal.

Lime and limestone wet scrubbing technologies use very similar processes for controlling SO_2. Lime wet scrubbing systems use calcium oxide (lime) in an aqueous slurry to remove SO_2 from the flue gas, whereas limestone systems use a calcium carbonate (limestone) slurry. In both systems, SO_2 is absorbed into the slurry where it reacts with the calcium reagents to form calcium sulfite and calcium sulfate. These components are less soluble in water than lime or limestone and precipitate out of solution, thus increasing the suspended solids concentration of the slurry.

From the scrubber, the slurry flows to a holding tank where make-up lime or limestone and water are added. Most of the slurry is pumped back to the scrubber for further absorption of SO_2. A fraction of the slurry, however, is pumped from the holding tank to a solids concentrating section where it is dewatered and converted to a sludge that is approximately half calcium solids and half water. The liquid removed by dewatering in the solids concentrating section is pumped back to the holding tank. The sludge is disposed of in a solid waste disposal facility.

In both lime and limestone wet scrubbing systems, there are four system parameters that have a major influence on SO_2 removal efficiency. These parameters are the scrubber liquid-to-flue gas ratio (L/G), the contact area in the scrubber, the calcium-to-sulfur ratio (Ca/S), and the pH. Increasing any one or all of these parameters will improve the SO_2 removal efficiency of the scrubber. Since limestone is less soluble in water and less reactive than lime, all of these parameters, except pH, must collectively be higher for limestone wet scrubbing systems than for lime wet scrubbing systems. The pH of limestone systems will be lower than the pH in lime systems because of the natural carbonate/bicarbonate buffer. Recently, the use of mass transfer additives such as adipic acid and dibasic acid has been shown to improve the performance of limestone wet scrubbing systems dramatically, thus enabling them to operate with L/G ratios, Ca/S ratios, and contact areas similar to those of lime wet scrubbing systems. When the system parameters listed above are properly controlled, both lime wet scrubbing systems and limestone wet scrubbing systems with mass transfer additives can achieve short-term SO_2 removal efficiencies in excess of 90 percent.

Lime and limestone wet scrubbing systems together comprise over 70 percent of the flue gas desulfurization systems installed on electric utility steam generating units in the United States. However, only one lime wet scrubbing system and one limestone wet scrubbing system are currently treating the combustion flue gases of industrial-commercial-institutional steam generating units. The lime wet scrubbing system began operation in 1978. The steam generating unit has a heat input capacity of 73 MW (250 million Btu/hour) and combusts a coal with a sulfur content of 2,925 ng

SO_2/J (6.8 lb SO_2/million Btu) heat input. At least part of the reason for installing this lime wet scrubbing system was to use the lime slurry waste byproduct to neutralize and precipitate metal ions out of wastewater streams generated by other processes within the plant.

The limestone wet scrubbing system began operation in 1976. The steam generating unit has a heat input capacity of 40 MW (130 million Btu/hour) and combusts a coal with a sulfur content of 2,880 ng SO_2/J (6.7 lb SO_2/million Btu) heat input. However, this system operates only 6 months out of the year because the steam generating unit is used only during the winter months for space heating.

Due to the greater ease of operation of other wet scrubbing technologies, such as dual alkali and sodium wet scrubbing, lime and limestone wet scrubbing systems have not been widely applied to industrial-commercial-institutional steam generating units. However, lime wet scrubbing and limestone wet scrubbing systems using mass transfer additives have been successfully applied to numerous utility steam generating units to achieve high SO_2 removal efficiencies. Because the mechanisms for controlling SO_2 emissions from utility steam generating units are essentially the same as for industrial-commercial-institutional steam generating units, these two control technologies are considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

Dual alkali wet scrubbing systems, like lime and limestone wet scrubbing systems, produce a waste sludge composed of calcium sulfite and sulfate salts. However, unlike lime and limestone wet scrubbing systems, dual alkali systems use aqueous solutions of sodium hydroxide or sodium carbonate to absorb SO_2.

In dual alkali wet scrubbing, the combustion flue gases are contacted with an aqueous solution of sodium hydroxide or sodium carbonate in an absorber or scrubber. The SO_2 contained in the flue gases is absorbed in the liquid. The liquid flows from the scrubber to a holding tank where make-up water and sodium hydroxide or sodium carbonate are added. Most of the liquid in the holding tank is recycled to the scrubber, while a small fraction of it is diverted to a lime reaction tank. Lime is added to the liquid and reacts with the sodium sulfites and sulfates in solution to produce calcium sulfite and sulfate, which precipitate from the liquid. The precipitate is separated from the liquid and concentrated to a sludge using the same dewatering techniques that are used in lime and limestone wet scrubbing systems. Liquid from the lime reaction tank, along with liquid from the dewatering processes, is recycled to the holding tank for recirculation to the scrubber.

As with the lime and limestone wet scrubbing systems, scrubber liquid-to-gas ratio, scrubber contact area, reagent-to-sulfur ratios [in this case sodium-to-sulfur (Na/S) rather than calcium-to-sulfur (Ca/S)], and pH are important factors affecting SO_2 removal efficiency. As each of these factors is increased, the SO_2 removal efficiency will also be increased. However, the scrubber liquid-to-gas ratio and scrubber contact area are not as important as the Na/S ratio in dual alkali scrubbing because sodium alkaline reagents are much more soluble in water than calcium alkaline reagents. At sufficiently high Na/S ratios (between 1.6 and 2.0), SO_2 removal efficiencies in excess of 90 percent are achievable over a relatively wide range of liquid-to-gas ratios and scrubber contact areas.

Since 1974, 13 dual alkali wet scrubbing systems have been installed on industrial-commercial-institutional steam generating units. The sizes of these units range from 10 to 400 MW (40 to 1,400 million Btu/hour) heat input capacity. All but one of these dual alkali wet scrubbing systems have been installed on coal-fired steam generating units, and the range of fuel sulfur content has been from 350 to 1,300 ng SO_2/J (1.6 to 6.0 lb SO_2/million Btu). Consequently, dual alkali wet scrubbing is considered demonstrated for the purpose of developing new source performance standards limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

Sodium scrubbing, like dual alkali scrubbing, removes SO_2 from the flue gases by absorbing the SO_2 in aqueous solutions of sodium hydroxide or sodium carbonate. As with dual alkali systems, the liquid from the scrubber is mixed in a holding tank with water and make-up sodium reagent and most of the liquid is recycled to the scrubber. A portion of the liquid, however, is removed from the holding tank for disposal as wastewater.

In most areas, the wastewater byproduct from sodium wet scrubbing can either be treated at the plant site or discharged to a publicly owned treatment facility for treatment prior to discharge. The treatment and disposal of wastewater to surface waters has been widely permitted pursuant to Federal and State water quality regulations, and does not present an obstacle to the use of this technology for SO_2 control. The character of the waste stream can be rendered relatively inert through the simple oxidation of all sulfur-bearing compounds to sulfate which eliminates the potential chemical oxygen demand of the waste on the receiving waters. Similarly, these waste streams have been found in practice to be compatible with the operation of publicly owned treatment works, and have been readily accepted by those systems. In arid areas, the wastewater stream is usually discharged to an evaporation pond. In California it is sometimes injected with the steam used in thermally-enhanced oil recovery operations.

As with dual alkali systems, the major factor affecting SO_2 removal efficiency for sodium wet scrubbing systems is the Na/S ratio. Since sodium is highly soluble in water, high alkalinities in the scrubbing liquor are easily maintained and consistently high SO_2 removal efficiencies are achievable. Removal efficiencies in excess of 90 percent are typical for many currently operating sodium wet scrubbing systems.

There are over 500 sodium wet scrubbing systems currently in use on industrial-commercial-institutional steam generating units. These systems are primarily operating on oil-fired steam generating units, although there are more than 10 sodium wet scrubbing systems operating on coal-fired units. These steam generating units range in size from 5 to 230 MW (20 to 800 million Btu/hr) heat input capacity, and the range of fuel sulfur content is 344 to 2,580 ng SO_2/J (0.8 to 6.0 lb SO_2/million Btu) heat input. Therefore, sodium wet scrubbing is considered demonstrated for the purpose of developing standards of performance limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

4.2. PARTICULATE MATTER EMISSIONS FROM OIL COMBUSTION

Particulate matter emissions from the combustion of fuel oils in industrial-commercial-institutional steam generating units are composed of ash, various sulfates, carbonaceous material and, occasionally, additives.

The ash component is comprised of non-combustible metals and salts present in the fuel oil. Fuel oil ash content generally increases with increasing sulfur content.

The sulfur component of the particulate matter is composed primarily of various sulfate salts. They are the product of fuel sulfur interaction with the combustion air, metals present in the fuel ash, and the internal surfaces of the steam generating unit. The contribution of the sulfur component to particulate matter emissions is proportional to the sulfur content of the fuel oil.

The third major component of particulate matter emissions from fuel oil combustion is carbonaceous compounds. These compounds are tar-like substances resulting from incomplete fuel combustion. Although carbonaceous compounds can be the most significant component of particulate matter from oil under conditions of poor combustion, these compounds will be negligible with good burner operation and maintenance.

An occasional component of particulate matter emissions is fuel additives. These additives are anti-corrosion and anti-slagging compounds that are blended into high sulfur, high ash residual fuel oils to protect the steam generating unit from corrosion and slagging. Additives are not commonly required with low sulfur, low ash fuel oils.

A variety of methods can be employed to reduce particulate matter emissions from oil combustion in industrial-commercial-institutional steam generating units. These methods can be grouped into pre-combustion control (i.e., the use of low ash/low sulfur fuel oil) and post-combustion control (i.e., add-on equipment such as wet scrubbers and electrostatic precipitators).

4.2.1 Low Sulfur Oil

Pre-combustion control, or the use of low sulfur fuel oil, is an effective means of controlling particulate matter emissions because of the relationship that generally exists between fuel sulfur content and particulate matter emissions. Many studies, such as those supporting the development of the manual, "Compilation of Air Pollutant Emission Factors" (AP-42), have established that particulate matter emissions from fuel oil combustion are generally proportional to fuel sulfur content.

As discussed previously, a well operated and maintained steam generating unit firing oil will have very little carbonaceous material in its particulate matter emissions. Because the other three components of particulate matter emissions - ash, sulfur oxides, and additives - are each generally proportional to the sulfur content of the fuel oil, the use of low sulfur fuel oil is a very effective means of reducing particulate matter emissions from fuel oil combustion. When compared to firing a high sulfur fuel oil in a steam generating unit, medium sulfur fuel oils can reduce particulate matter emissions by as much as 40 percent, and low sulfur fuel oils can reduce particulate matter emissions by as much as 65 to 80 percent.

As discussed previously, low sulfur fuel oils are available and are currently widely used in industrial-commercial-institutional and utility steam generating units to reduce SO_2 emissions from oil combustion. Low sulfur fuel oils, therefore, are considered demonstrated for the purpose of developing new source performance standards limiting particulate matter emissions from new, modified, and reconstructed oil-fired industrial-commercial-institutional steam generating units.

4.2.2 Post-Combustion Control

Post-combustion control is the most widely employed approach used for the control of particulate matter emissions. Post-combustion control techniques employed to control particulate matter emissions from steam generating units include various types of mechanical collectors, sidestream separators, fabric filters, wet scrubbers, and electrostatic precipitators.

Mechanical collection is a well established technology that employs centrifugal separation to remove particles from the flue gas stream. Although mechanical collectors have been widely used to control particulate matter emissions, they have seen limited application to oil-fired steam generating units. The majority of the particulate matter emitted from oil-fired steam generating units is less than 10 μm in diameter. Mechanical collectors, however, are principally effective on particulate matter larger than 10 μm in diameter. Because of the general ineffectiveness of mechanical collectors in reducing particulate matter emissions from oil-fired steam generating units, they are not considered demonstrated for the purpose of developing these new source performance standards.

Fabric filtration is a particulate matter control technology that has been used very effectively to control particulate matter emissions from coal-fired steam generating units. A fabric filter system (also known as a baghouse) is one which directs particle-laden flue gas through a number of fabric bags where the particles are collected as a filter cake on the bag surface. The filter cake is dislodged from the bag surface by various sonic and mechanical shaking techniques, and is removed from the floor of the fabric filter structure for disposal.

Although fabric filters have been frequently applied to coal-fired steam generating units, they have seen limited application to oil-fired steam generating units. Many fuel oils produce a particulate matter with a sticky or tar-like property. This physical property has caused difficulties in dislodging the filter cake from the fabric filter surface and has resulted in filter plugging and short filter life. Consequently, the general incompatibility of fabric filters with particulate matter emitted from oil combustion precludes their consideration as demonstrated for the purpose of developing new source performance standards limiting particulate matter emissions from new, modified, and reconstructed oil-fired industrial-commercial-institutional steam generating units.

Sidestream separators are modified mechanical collectors in which a fraction of the flue gas stream is withdrawn from the mechanical collector ash hopper and is passed through a small fabric filter. Although sidestream separators have not been applied to oil-fired steam generating units, they are expected to exhibit the same ineffectiveness exhibited by mechanical collectors and the same incompatibility exhibited by fabric filters. Consequently, sidestream separators are not considered demonstrated for the purpose of developing new source performance standards limiting particulate matter emissions from new, modified, and reconstructed oil-fired industrial-commercial-institutional steam generating units.

Electrostatic precipitators (ESP's) are in commercial use for the control of particulate matter emissions from utility steam generating units firing fuel oils. Electrostatic precipitators remove particulate matter from flue gases by electrically charging the suspended particles and precipitating them onto an oppositely charged collection plate. The principal design factor affecting the performance of ESP's is the specific collection plate area, expressed as the ratio of the collection plate area to the flue gas flow rate. For a given steam generating unit and fuel type, a larger specific collection plate area will provide improved particulate matter collection efficiency. Consequently, the performance of a given ESP design will be independent of the steam generating unit size as long as the specific collection area remains constant.

A study of 20 utility steam generating units equipped with ESP's demonstrated that the particulate matter emission control efficiency of ESP's ranges from 40 to over 80 percent, and averages over 50 percent. Furthermore, these ESP's have been in service for many years and do not exhibit the incompatibility problems exhibited by fabric filters.

Consequently, electrostatic precipitators are considered demonstrated for the purpose of developing new source performance standards limiting particulate matter emissions from new, modified, and reconstructed oil-fired industrial-commercial-institutional steam generating units.

Wet scrubbers are a second post-combustion control technique that has been effectively applied to oil-fired steam generating units. Wet scrubbers remove particulate matter from flue gases by contacting the flue gas with an aqueous liquor. The particulate matter is entrained in the aqueous liquor and removed from the scrubber. The performance of wet scrubbers in controlling particulate matter is proportional to the turbulence generated in the scrubber. By designing the wet scrubber with a long residence time and extended surface area, the wet scrubber will be an effective particulate matter control device in addition to controlling SO_2 emissions.

Over 250 wet scrubbers have been identified that are in use on oil-fired industrial-commercial-institutional steam generating units. The vast majority of these wet scrubbers are designed for the removal of SO_2 emissions in conjunction with the removal of particulate matter emissions. The particulate matter removal efficiency of these wet scrubbing systems generally ranges from 65 to over 90 percent.

Consequently, wet scrubbers are considered demonstrated for the purpose of developing these new source performance standards.

4.3 PARTICULATE MATTER EMISSIONS FROM COAL COMBUSTION

The June 19, 1984 proposed standards for industrial-commercial-institutional steam generating units (49 FR 25102) discussed various methods for controlling particulate matter emissions from coal-fired steam generating units. The particulate matter emission limits established in the proposed standard for coal-fired steam generating units were based on the performance of fabric filters and ESP's.

As discussed above concerning control of particulate matter emissions from oil-fired steam generating units, however, flue gas desulfurization (FGD) systems are also capable of reducing particulate matter emissions from coal-fired steam generating units. Most FGD systems inherently employ some type of particulate matter control system as an integral part of their design. In the case of lime spray drying systems, for example, the particulate matter control system is generally a fabric filter. In the case of wet FGD systems, such as lime or limestone, dual alkali, or sodium scrubbing systems, the wet scrubber results in some reduction in particulate matter emissions.

As discussed in the June 19, 1984 proposal notice, wet scrubbing systems as well as fabric filters and ESP's are considered demonstrated. FGD systems, therefore, are also considered demonstrated for purposes of developing these new source performance standards.

5.0 PERFORMANCE OF DEMONSTRATED EMISSION CONTROL TECHNOLOGIES

As discussed below, SO_2 emission data gathered to assess the performance of low sulfur fuel combustion, combustion modification, and FGD technologies in reducing SO_2 emissions from industrial-commercial-institutional steam generating units exhibit significant variation about the mean or average performance level. As an example, 5 days of SO_2 emission data from the combustion of low sulfur coal in an industrial steam generating unit are shown in Figure 5-1; the variability in emissions about the mean is apparent. Data on emissions and SO_2 removal efficiency from steam generating units using combustion modification and FGD systems follow a similar pattern.

For low sulfur coal, this variability is due to many factors, including the lack of uniformity in sulfur deposits in coal seams, as well as coal mining techniques and coal handling procedures. These same factors influence the variability in SO_2 emissions observed from combustion modification and FGD systems. Other factors affecting performance variability associated with combustion modification and FGD systems are the performance characteristics of individual equipment components and the interactions of these components. Although oil exhibits variability in sulfur content among reservoirs, this variation is minimized through the processing, refining, storage, and handling of fuel oil prior to combustion in a steam generating unit.

As a result of this variability, no single data point can be considered representative of performance. Rather, data must be averaged over some period of time to assess performance. The longer the averaging period selected, the less variability remains in the data and the more accurate, or more representative, the average performance level becomes as an assessment of long-term performance.

Statistically, variability may be measured in terms of standard deviation and autocorrelation. The standard deviation may be generally described as a measure of the deviation or scatter exhibited by a set of measurements around the mean or average of those measurements. The standard

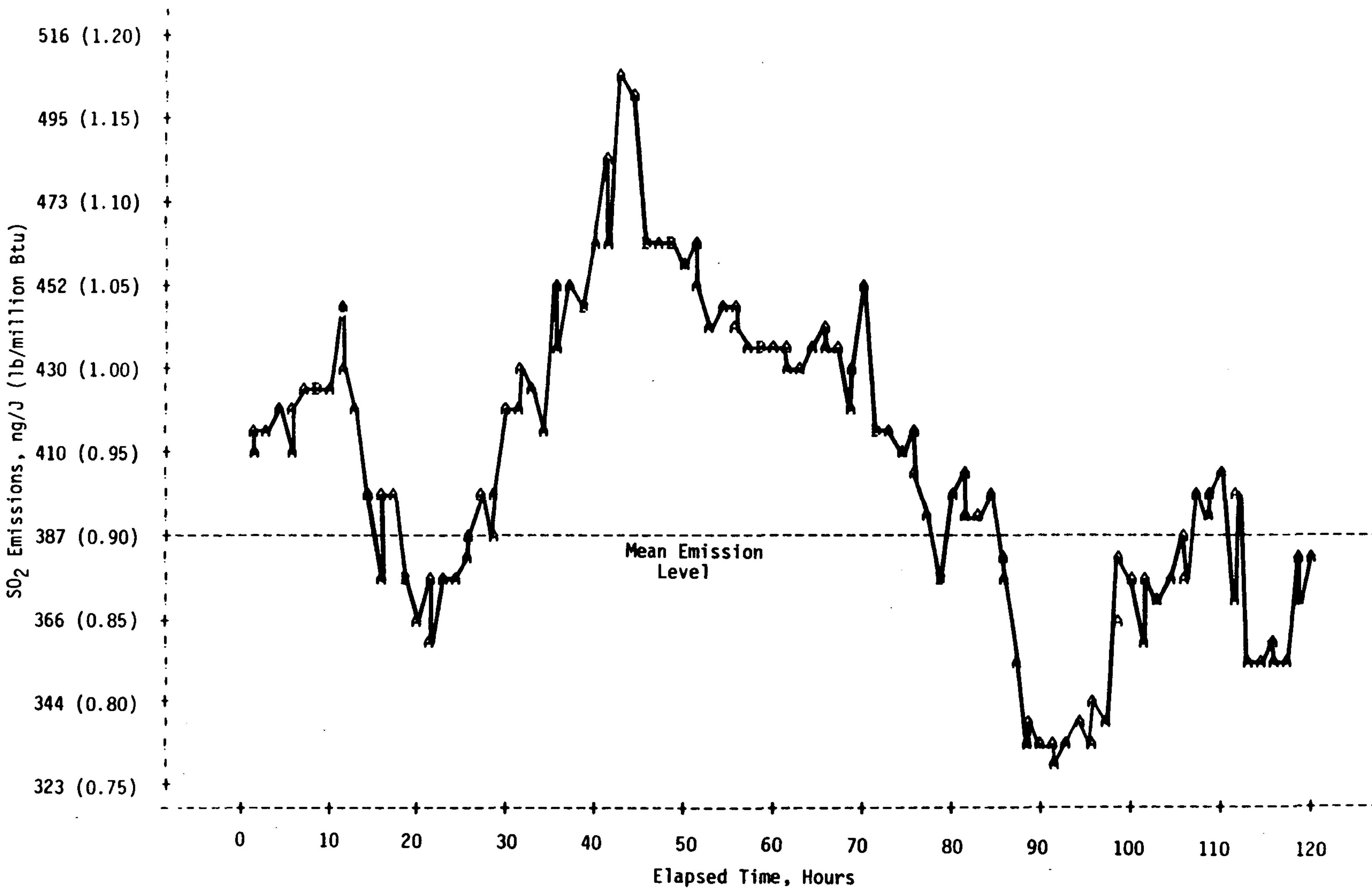

Figure 5-1. Typical SO_2 Emissions Data for Low Sulfur Coal Combustion

deviation is sometimes expressed as the relative standard deviation by dividing the standard deviation by the mean. The larger the relative standard deviation, the greater the variability exhibited by the data. The lower the relative standard deviation, the less the variability exhibited by the data.

Autocorrelation is a measure of the association or dependence between successive measurements. An autocorrelation near 1.0 indicates that successive measurements are similar in magnitude. An autocorrelation near zero indicates there is little relationship between successive measurements.

The variability exhibited by SO_2 emission data tends to decrease as the period over which the data are averaged increases. As discussed below, when emission data from low sulfur coal combustion are averaged over a 24-hour period, a relative standard deviation of about 20 percent and an autocorrelation of about 0.7 are representative of much of the data gathered to assess performance. Using these estimates of relative standard deviation and autocorrelation, Figure 5-2 illustrates the effect of averaging period length on SO_2 emissions variability.

Figure 5-2 assumes that the mean SO_2 emission rate or long-term performance level is 430 ng SO_2/J (1.0 lb SO_2/million Btu) heat input. The solid lines represent the outer limits or extreme values of the SO_2 emission rates contained within two standard deviations of the mean of the data (i.e., approximately 95 percent of the data lies between the two solid lines).

Figure 5-2 clearly shows that the longer the period selected for averaging SO_2 emissions data, the lower the variability exhibited by the data. For example, if a 24-hour period were selected for averaging the data, the variability observed in the data would range from as low as 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input to as high as 602 ng SO_2/J (1.4 lb SO_2/million Btu) heat input, a range of ± 40 percent around the mean. If a 30-day period were selected for averaging the data, on the other hand, the variability observed in the data would range from 366 ng SO_2/J (0.85 lb SO_2/million Btu) heat input to 495 ng SO_2/J (1.15 lb SO_2/million Btu) heat input, a range of ± 15 percent. Compared to a 24-hour averaging period,

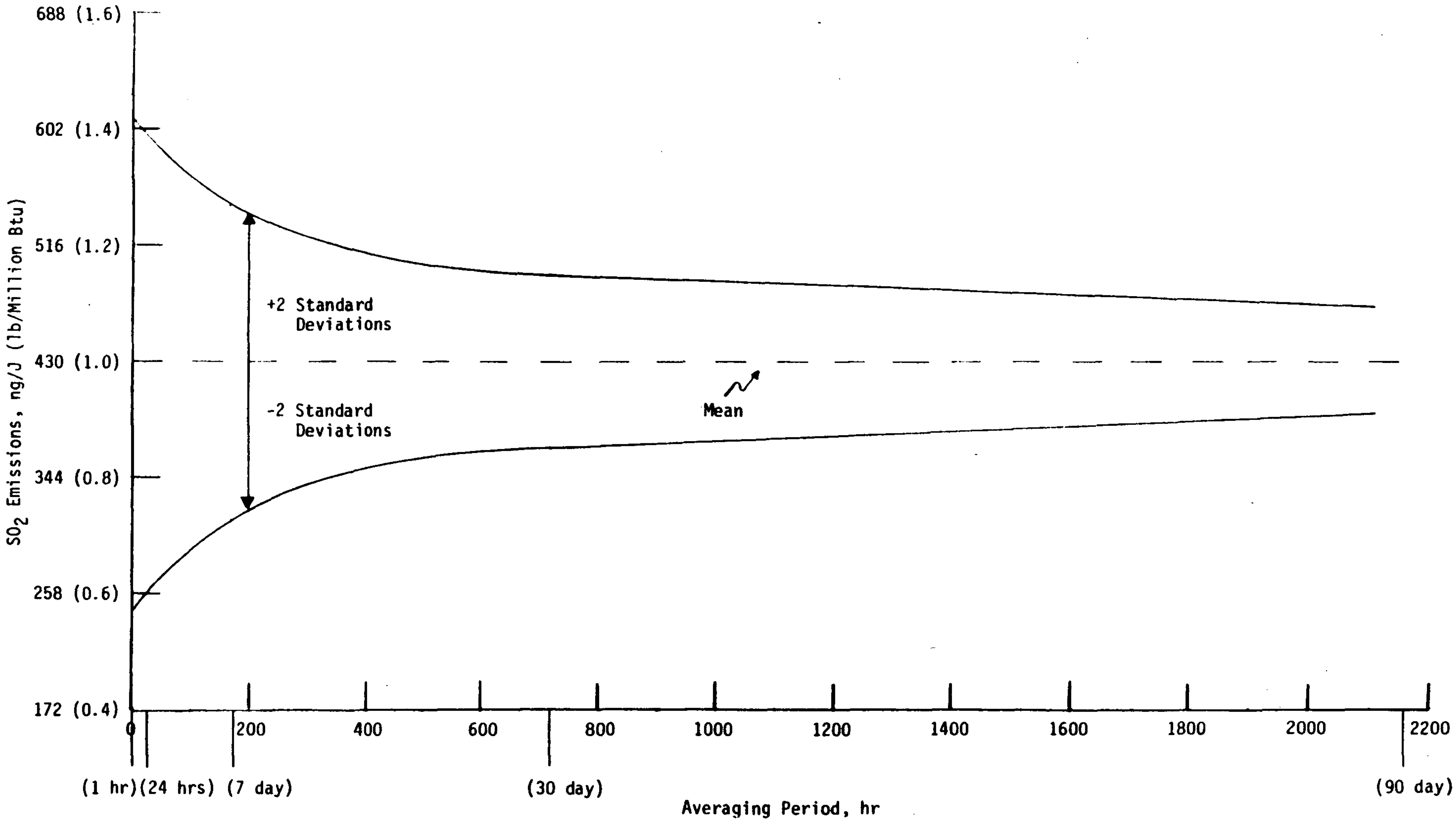

Figure 5-2. Impact of Averaging Period on SO_2 Emissions Data Variability

therefore, a 30-day averaging period reduces the variability exhibited by the data by somewhat more than half.

When considering what averaging period to use to minimize data variability, it is important to recognize that the averaging period selected for assessing the performance of SO_2 control technologies will also be the averaging period selected for determining compliance with standards based on these technologies. For a shorter averaging period, the performance level required by the standard may be less stringent (or the emission limit to accommodate a given performance level may be higher). This is because greater variability is observed in performance measured over short averaging periods. Conversely, for a longer averaging period, the mean performance level required by the standard may be more stringent (or the emission limit to accommodate a given performance level may be lower). This is because lower variability is observed in performance measured over longer averaging periods.

As mentioned above, the longer the averaging period used to measure performance, the more realistic this measure of performance is in terms of accurately reflecting the long-term or average performance of the system. From the point of view of enforcing compliance with standards, however, the longer the averaging period selected to measure performance, the longer the period can be between the time a source begins to operate and the time an initial assessment can be made of whether that source is in compliance with the standards. An averaging period of one year, for example, would require a year of operation before it could be determined if the source was in compliance. An averaging period should be selected, therefore, that is long enough to minimize variability, but short enough to permit timely enforcement of the standards after a new source commences operation.

As shown in Figure 5-2, variability declines rapidly between averaging periods of 1 hour and 30 days and then declines much more slowly beyond 30 days. An averaging period of 30 days, therefore, is long enough to yield results representative of long-term performance. Similarly, an averaging period of 30 days is also short enough to permit timely enforcement of a standard after a new source begins operation. In addition, use of a 30-day rolling average, as opposed to a 30-day discrete average, allows enforcement of standards on a daily basis following the first 30-day period. As a result, a 30-day rolling average was selected for assessing the performance of low sulfur fuels, combustion modification, and FGD technologies for the purpose of developing standards of performance limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units.

5.1 LOW SULFUR COAL

As discussed in "Selection of Demonstrated Emission Control Technologies," the use of low sulfur coal is considered demonstrated for the purpose of developing standards of performance for coal-fired industrial-commercial-institutional steam generating units. Low sulfur coals include both those with naturally occurring low sulfur content and those that have had sulfur removed by processing.

Sulfur dioxide emissions resulting from the combustion of coal in steam generating units vary considerably because the sulfur content of coal is not homogeneous. Coal produced from a single seam by the same mine may vary substantially in sulfur content. In addition to sulfur content, the heat content of coal also varies. Therefore, when expressing fuel sulfur content on a heat content basis (ng/J or lb/million Btu), sulfur content variability is actually a measure of the joint variability of these two coal properties. For these reasons, there will be substantial variation in the SO_2 emissions (ng/J or lb/million Btu) resulting from the combustion of coal.

The amount of variation is influenced by variation in the natural distribution of sulfur throughout the seam from which the coal is mined, and can also be influenced by the manner in which the coal is mined. To represent the distribution of sulfur deposits in a coal seam, lines of constant sulfur content (called isolines) can be drawn on a map of a coal deposit as shown in Figure 5-3. Mining coal in a direction parallel to a sulfur isoline will produce coal with less variation in sulfur content than mining coal in a direction perpendicular to the sulfur isolines. In

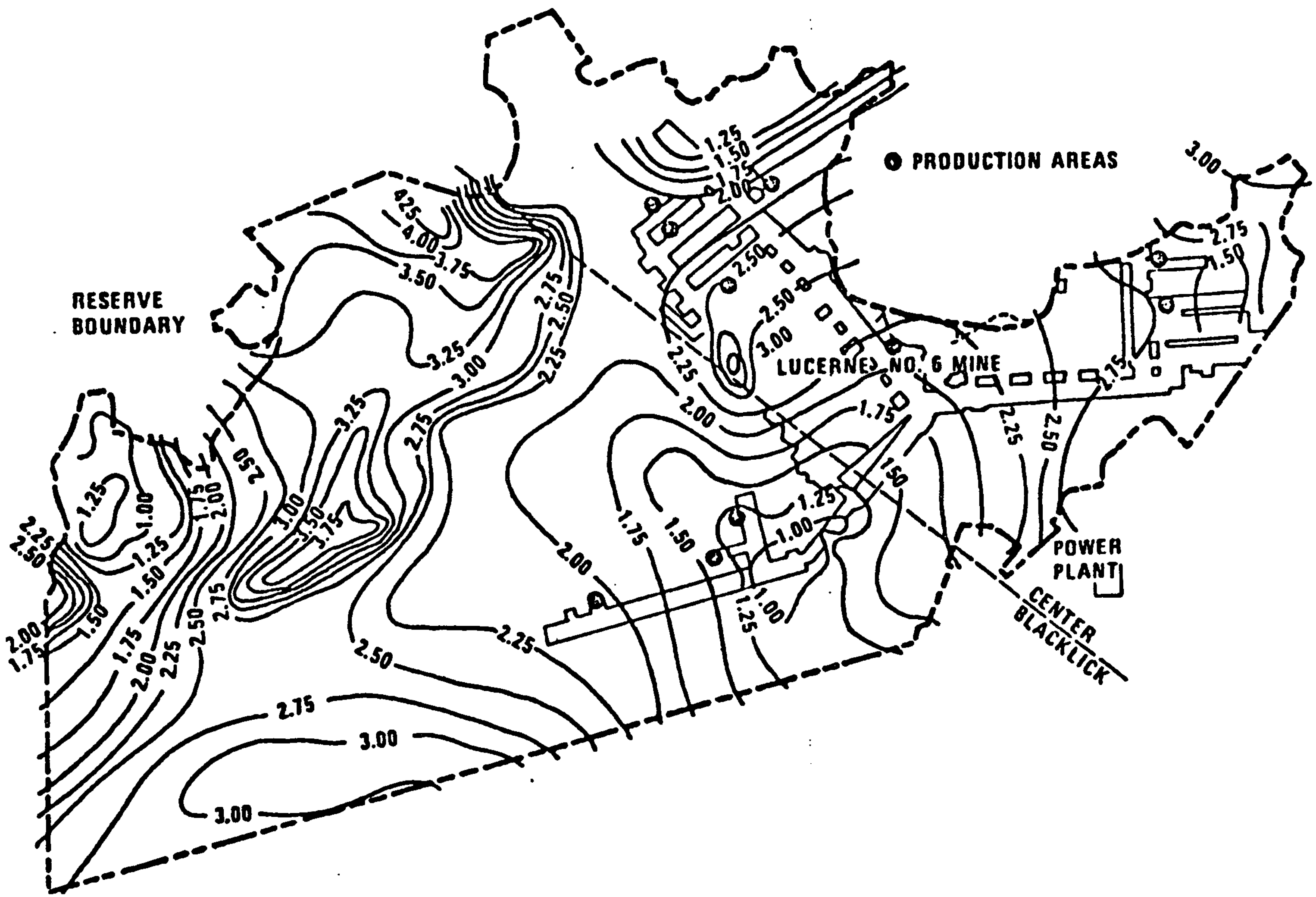

Figure 5-3. Map Showing Sulfur Isolines for "E" Seam of Helvetia No. 6 Reserves

addition, coal may be mined simultaneously from several locations within the same seam. The sulfur content of the coal from each location and the degree of mixing the coals undergo will influence overall variability in the sulfur content of the coal produced from the mine.

The amount of variation is also influenced by the extent to which coal is cleaned prior to shipment (see "Selection of Demonstrated Emission Control Technologies"). Physical coal cleaning (PCC) removes a large portion of the impurities normally found in raw coal and reduces the variation in the sulfur content of the coal. It has been reported that PCC reduces coal sulfur variability by approximately 50 percent.

Finally, the amount of variation is also influenced by coal handling practices at the mine, at the PCC plant, or at the steam generating unit site. Coal handling, for example, may involve blending coals to produce a coal blend that is more uniform in sulfur content than the individual coals. Three coal blending methods are commonly employed. These include bed blending, bunker blending, or a combination of the two. Bed blending involves spreading coals from various sources over a large area in series of horizontally layered beds. Bunker blending involves taking coals from various storage facilities (bunkers, silos, or open piles) in fixed proportions to create a coal blend that is more uniform. One combination method involves taking coals from various storage facilities in fixed proportions and then blending them using the bed blending method described above.

Coal blending decreases the variability in coal sulfur content by physically averaging the sulfur contents of coals. The degree of reduction in variability, however, depends on the properties of the coals blended and the specific blending method.

To assess the performance of low sulfur coal as an emission control technique, SO_2 emission data were gathered to identify the variation in emissions typically observed during the combustion of coal. These data, which are summarized in Table 5-1, were gathered from industrial-commercial-institutional steam generating units and electric utility steam generating units. For all data sets except CEM-5, the data were collected by

TABLE 5-1. CONTINUOUS EMISSION MONITORING (CEM) DATA

Data Set No.	Type of Unit	Number of Hourly Data Points[a]	Raw or Washed Coal	Type of Coal	Daily Coal Lot Size (tons)	Mean Emissions (lb SO_2/million Btu)	Daily RSD (Percent)	Daily Autocorrelation
CEM-1	Industrial	1,914	-	Bituminous	500	0.92	10	0.49
CEM-2	Industrial	1,848	Raw	Subbituminous	500	0.64	32	0.66
CEM-3	Industrial	1,152	Raw	Subbituminous	330	0.79	29	0.63
CEM-4	Industrial	1,368	Washed	Bituminous	175	0.99	11	0.67
CEM-5	Institutional	792[b],	Washed	Bituminous	150	1.44	9	-
		864[b]	Washed	Bituminous	150	1.48	11	-
CEM-6	Utility	1,896	Raw	Bituminous	3,500	0.92	9	0.67
CEM-7	Utility	2,712	Raw	Subbituminous	6,500	0.45	17	0.79
CEM-8	Utility	1,944	Raw	Subbituminous	7,500	0.78	15	0.59
CEM-9	Utility	1,200	Washed and Raw	Bituminous	5,000	0.83	8	0.72
CEM-10	Utility	1,392	Raw	Subbituminous	4,500	0.80	9	0.73
CEM-11	Utility	612	-	Subbituminous	900	1.06	11	-

[a]Total hours for which data are available; i.e., the total number of hours spanned by the test multiplied by the data capture rate.

[b]These data are based on Test Method 6B; therefore, only daily averages are available. For consistency with other data sets, the number of hours reported in this column reflects 24 hourly data points for the days for which daily averages were available.

continuous emission monitoring systems (CEMS) that had successfully completed CEMS performance specification tests. The data for data set CEM-5 were collected using Reference Method 6B.

Data set CEM-1 is based on hourly SO_2 emission measurements from an industrial steam generating unit for the period November 1983 through January 1984. This unit has a heat input capacity of 226 MW (780 million Btu/hour). The coal burned at the plant is primarily from the Upper Banner and Elkhorn seams of Virginia and western Kentucky. For a 6-day period in December 1983, data were not available due to steam generating unit outage. The data were collected with CEMS equipment that had passed certification tests in November 1982. Daily coal lot size determined from the steam flow rate data is 450 Mg (500 tons). This is based on several assumptions: steam enthalpy of 2,560 kJ/kg (1,100 Btu/lb); steam generating unit efficiency of 83 percent, and coal heating value (as received) of 31,500 KJ/kg (13,540 Btu/lb).

Data sets CEM-2 and 3 are based on data from two industrial pulverized coal-fired steam generating units. These data were collected from March through July 1979 using continuous SO_2 analyzers that were certified in September 1978. There were numerous gaps in the data for both steam generating units, although the gaps did not necessarily occur at the same time. Operating personnel at these two steam generating units could not recall the reasons for the data gaps. These steam generating units typically fire a western subbituminous coal with a heating value of 29,560 kJ/kg (12,710 Btu/lb) on a dry basis. Daily coal lot sizes for these steam generating units, which have heat input capacities of about 171 MW (583 million Btu/hour) and 256 MW (875 million Btu/hour), are estimated at 300 and 454 Mg (330 and 500 tons), respectively. These estimates assume an average steam generating unit load of 60 percent, an efficiency of 83 percent, and steam enthalpy of 2,560 kJ/kg (1,100 Btu/lb).

Data set CEM-4 is based on data from a 78 MW (265 million Btu/hour) heat input capacity pulverized coal-fired steam generating unit located at an industrial facility. Data were collected from July through September 1982 using a CEMS certified in early 1982. The steam generating unit is shut down each Friday night at midnight and restarts at 7 A.M. each Monday morning. For this reason, there are numerous gaps in the data. This steam generating unit fires eastern bituminous coal, which may be raw, washed, or blended to produce a compliance coal. Daily coal lot sizes are estimated at 159 Mg (175 tons). This estimate assumes an average load of 60 percent, a steam generating unit efficiency of 83 percent, and a steam enthalpy of 2,560 kJ/kg (1,100 Btu/lb).

Data set CEM-5 consists of 24-hour SO_2 values (Reference Method 6B) from a 36 MW (125 million Btu/hour) heat input capacity institutional electric power generating plant. The data collected from this unit are for a 70-day period in August through November 1979. During this period the plant was burning washed eastern Kentucky coal with an average heating value of 31,400 kJ/kg (13,500 Btu/lb). The daily data capture rates for two parallel data collection operations were 46 (33 days) and 51 (36 days) percent. Based on coal consumption rate data for this period, daily coal lot size is about 135 Mg (150 tons).

Data set CEM-6 is from a 1,290 MW (4,450 million Btu/hour) heat input capacity pulverized coal steam generating unit and spans the period January 1 through April 1, 1984. The data were collected with CEMS equipment that had passed certification tests in October 1983. During the period of data collection, the unit was firing an unwashed low sulfur bituminous coal from three different seams at three mines in Utah. This unit is equipped with an FGD system and data were collected at the inlet to the FGD. All coal is transported by truck at a rate of 13,650 Mg (14,000 tons) per day. Some limited blending takes place at the plant site.

Data set CEM-7 is from a 2,100 MW (7,250 million Btu/hour) heat input capacity pulverized coal utility steam generating unit. This data set spans the period October 3, 1983 through February 29, 1984. The data were collected with CEMS equipment that had passed certification tests in November 1981. During this period, the unit was firing an unwashed subbituminous coal from one coal seam in the Powder River Basin in Wyoming and was shipped by unit train [approximately 10,000 Mg/train (11,000 tons/train)] approximately three times per week. No coal blending is performed intentionally. The average steam generating unit load was 60 percent.

Data from a 1,680 MW (5,800 million Btu/hour) heat input capacity pulverized coal steam generating unit make up data set CEM-8. The time period covered by this data set is May 1 through July 31, 1983. The data were collected with CEMS equipment that had passed certification tests in August 1981. Unwashed subbituminous coal from two coal seams in the Powder River Basin of Wyoming is fired in this steam generating unit. The coal is shipped by unit train [approximately 10,000 Mg/train (11,000 tons/train)] approximately three times per week. No coal blending is performed. The average steam generating unit load was 80 percent.

Data set CEM-9 is from a 795 MW (7,950 million Btu/hour) heat input capacity pulverized coal utility steam generating unit for the period November 21, 1983 through January 18, 1984. The data were collected with CEMS equipment that had passed certification tests in March 1983. Coal is received both by barge [approximately 12,250 Mg/barge (13,500 tons/barge)] and by unit train [approximately 6,500 Mg/train (7,200 tons/train]. The coal fired is supplied by six suppliers and is a low sulfur bituminous coal from mines in different seams in southern Appalachia. All but a small fraction of the coal is washed, achieving up to a 15 percent reduction in sulfur content. No intentional coal blending program is followed. During the data collection period, the average steam generating unit load was 66 percent.

Data set CEM-10 is from a 1,600 MW (5,500 million Btu/hour) heat input capacity pulverized coal utility steam generating unit and covers the period February 1 through April 10, 1984. The data were collected with CEMS equipment that had passed certification tests in May 1983. All coal is unwashed subbituminous coal from a single mine in the Powder River Basin of Wyoming. The coal is shipped by unit train [approximately 10,000 Mg/train (11,000 tons/train)] on a daily basis. No coal blending takes place at the plant, although some takes place at the supplier. Data were collected at the inlet to the FGD.

Daily coal lot sizes determined for the data sets CEM-7, 8, and 9 are based on daily average steam generating unit load data, 6-month average heat rate, and 6-month average coal heating value. The daily coal lot sizes for data sets CEM-6 and 10 are based on the average load data, heat rate, and coal heating value derived from data contained in data sets CEM-7, 8, and 9.

Data contained in data set CEM-11 were gathered at a pulverized coal utility steam generating unit rated at 360 MW (1,250 million Btu/hour) heat input capacity burning low sulfur subbituminous Wyoming coal with an average sulfur content of 0.5 percent and a reported heating value of 2,325 kJ/kg (1,000 Btu/lb). During these tests, conducted in January and February of 1979, SO_2 concentrations were monitored concurrently at the inlet and outlet of the FGD system. The data were collected with CEMS equipment that had passed certification tests in January 1979. The data are comprised of 612 hourly SO_2 emission values collected over a 30-day period. Daily coal lot size was calculated as 820 Mg (900 tons) based on daily steam generating unit load data. In this calculation the heat rate for the plant is assumed to be 10,545 kJ/KW-hour (10,000 Btu/KW-hour).

Several studies of the variability of SO_2 emissions resulting from coal combustion and the variability of coal sulfur content indicate that a time series statistical model, referred to as an AR(1) model, generally fits actual data quite well. In addition, a normal data distribution generally fits actual data as well as other data distributions, such as lognormal, when focusing on emissions performance averaged over a 30-day period. Consequently, an AR(1) model with a normal data distribution was used to determine the variability in each data set summarized in Table 5-1.

As mentioned earlier, two common statistical measures of variability are relative standard deviation (RSD) and autocorrelation (AC). Standard deviation is a measure of the spread of a set of data on either side of the mean. The relative standard deviation is calculated by dividing the standard deviation of a set of measurements by their mean. Autocorrelation is a measure of association between successive periodic measurements taken over a span of time.

Analysis of the data sets discussed above using an AR(1) time series statistical model yields the RSD and AC values presented in Table 5-1. These values represent the variability observed in SO_2 emissions in each data set for the amount of coal typically combusted in a 24-hour period (i.e., lot size). These values vary considerably because, as discussed above, many factors affect variability in SO_2 emissions. The RSD values range from 8 to 32 percent and the AC values range from 0.49 to 0.79.

This assessment of the variability in SO_2 emissions can be used to determine the performance of low sulfur coal as an emission control technique. Given values for RSD and AC, the AR(1) model can be used to estimate the ratio between the maximum expected 30-day rolling average SO_2 emission rate, assuming this maximum expected 30-day rolling average emission rate would only be exceeded once in 10 years, and the mean or long-term average SO_2 emission rate resulting from combustion of a particular coal. Multiplying this ratio by the long-term average emission rate yields the once in 10-year maximum expected 30-day rolling average SO_2 emission rate.

The data in Table 5-1 indicate that an RSD of 20 percent and an AC of 0.7 are reasonable assumptions to characterize the 24-hour variability in SO_2 emissions resulting from combustion of a coal with a high variability in SO_2 emissions. These values are conservative assumptions, particularly when combined with the statistical assumption that the resulting maximum expected 30-day rolling average SO_2 emission rate may only be exceeded once in 10 years. Assuming an RSD of 10 percent and an AC of 0.5, or an exceedance frequency of once a year rather than once in 10 years, would result in higher ratios between the maximum expected 30-day rolling average emission rate and the long-term average emission rate.

Using values of 20 percent and 0.7 for RSD and AC, respectively, the AR(1) model projects a ratio of 1.25 between the once in 10-year maximum expected 30-day rolling average emission rate and the long-term average emission rate.

Multiplying the long-term average emission rates associated with each coal type discussed in "Selection of Demonstrated Emission Control

Technologies" (see Table 4-1) by 1.25 yields the once in 10-year maximum expected 30-day rolling average emission rate resulting from combustion of each coal type. As shown in Table 5-2, SO_2 emissions could be reduced to or below an emission rate between 215 and 731 ng SO_2/J (0.5 and 1.7 lb SO_2/million Btu) heat input through the combustion of the low sulfur coal types. Similarly, SO_2 emissions resulting from the combustion of the medium sulfur and high sulfur coal types would not exceed an emission rate between 1,120 and 1,590 ng SO_2/J (2.6 and 3.7 lb SO_2/million Btu) heat input and between 2,240 and 2,710 ng SO_2/J (5.2 and 6.3 lb SO_2/million Btu) heat input, respectively. Standards of performance based on the combustion of low sulfur coals, therefore, could reduce or limit SO_2 emissions to the emission rates associated with low sulfur coals shown in Table 5-2.

As mentioned above, the data summarized in Table 5-1 were gathered from both industrial-commercial-institutional steam generating units and utility steam generating units. A utility steam generating unit, however, consumes much more coal than an industrial-commercial-institutional steam generating unit over a given period of time. As a result, the variability observed in SO_2 emissions from coal combustion in a utility steam generating unit reflects a much larger lot size than the variability observed in emissions from coal combustion in an industrial-commercial-institutional steam generating unit.

When samples are taken to estimate the value of a parameter, such as coal sulfur content, statistical theory indicates that smaller sample sizes should exhibit greater variability in the measured values of the parameter. On this basis, the question is frequently raised whether differences in lot size significantly influence the variability in SO_2 emissions resulting from coal combustion. Following this reasoning, industrial-commercial-institutional steam generating units might exhibit greater variability in SO_2 emissions than utility steam generating units.

As illustrated in Figure 5-4, however, when the data summarized in Table 5-1 are examined to determine if lot size has a significant influence on variability, no relationship between lot size and variability is observed. Figure 5-4 does not necessarily indicate that lot size has no

TABLE 5-2. MAXIMUM EXPECTED EMISSION RATES FOR COAL COMBUSTION

Type	Long-Term Average SO_2 Emissions ng SO_2/J(lb SO_2/million Btu)	Maximum Expected Emission Rate[a] ng SO_2/J(lb SO_2/million Btu)
Very Low Sulfur	172 (0.40)	215 (0.5)
Low Sulfur	404 (0.94)	516 (1.2)
Low Sulfur	589 (1.37)	731 (1.7)
Medium Sulfur	894 (2.08)	1,120 (2.6)
Medium Sulfur	1,256 (2.92)	1,590 (3.7)
High Sulfur	1,793 (4.17)	2,240 (5.2)
High Sulfur	2,150 (5.00)	2,710 (6.3)

[a]Once in 10-year maximum expected 30-day SO_2 rolling average (long-term average emission rate times 1.25, rounded to nearest tenth).

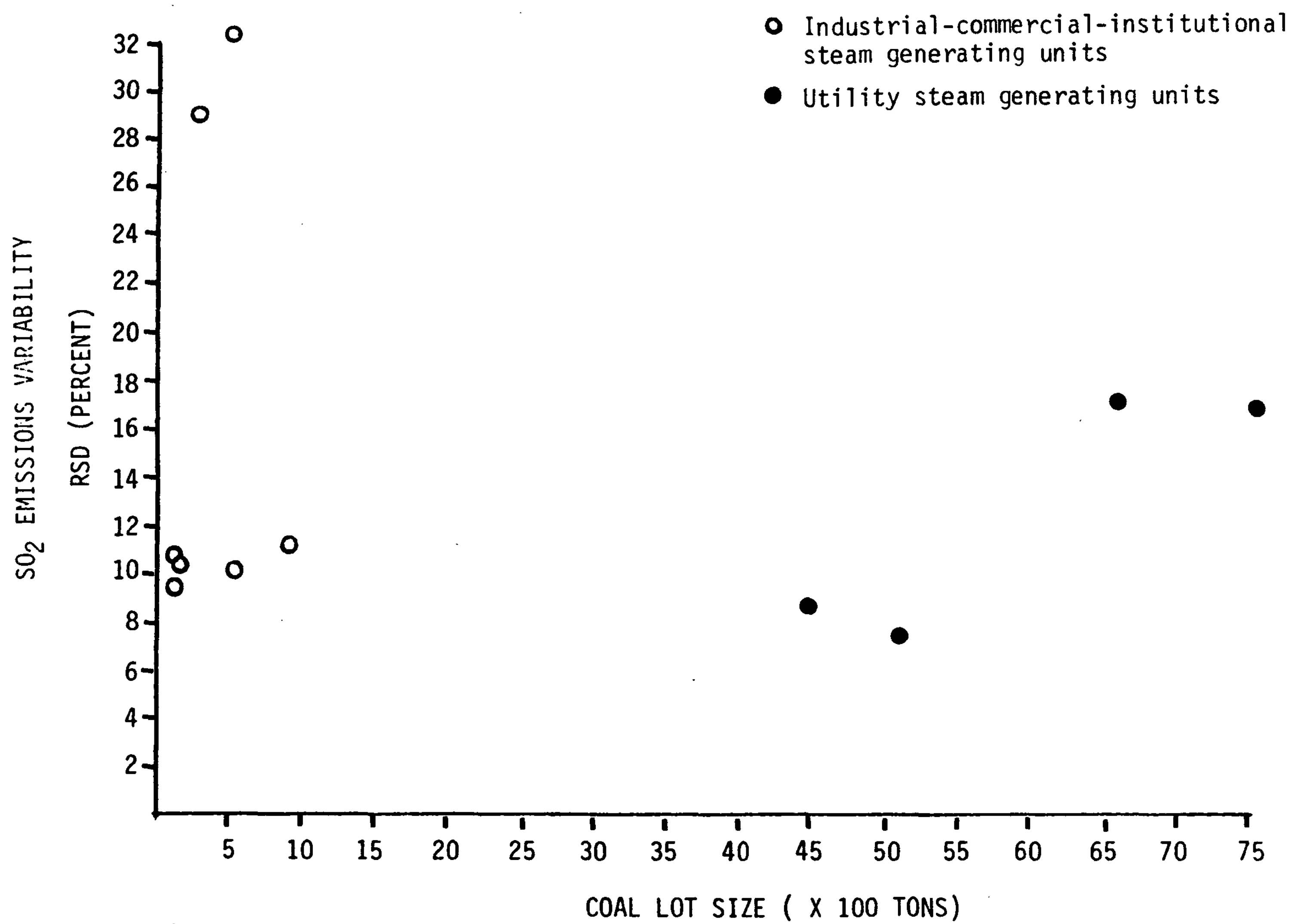

Figure 5-4. Coal Lot Size Versus SO_2 Emissions Variability for Utility and Industrial-Commercial-Institutional Steam Generating Units

influence on variability, but that the cumulative effect of other factors that also influence variability overshadows the effect of lot size.

From a purely statistical and theoretical point of view, the magnitude of the effect of lot size on emissions variability can be estimated. Assuming that an RSD of 20 percent typically reflects the variability in emissions from utility size boilers, then theoretically the smaller lot size associated with industrial size boilers would result in a typical RSD of 21.5 percent. Using values of 21.5 percent and 0.7 for RSD and AC, respectively, the AR(1) model projects a ratio of 1.26 between the once in 10-year maximum expected 30-day rolling average emission rate and the long-term average emission rate.

A ratio of 1.26 results in a slight increase in the once in 10-year maximum expected 30-day rolling average emission rates presented in Table 5-2. The once in 10-year maximum expected 30-day rolling average emission rate for a low sulfur coal with a long-term average emission rate of 413 ng/J (0.96 lb/million Btu) heat input, for example, would increase from 516 ng/J (1.20 lb/million Btu) to 521 ng/J (1.21 lb/million Btu) heat input.

As mentioned above, if less conservative values of 10 percent and 0.5 were assumed for RSD and AC, the ratio between the once in 10-year maximum expected 30-day rolling average emission rate and the long-term average emission rate decreases to 1.10. Use of this ratio would result in a decrease in the once in 10-year maximum expected emission rates presented in Table 5-2. The once in 10-year maximum expected 30-day rolling average emission rate for a low sulfur coal with a long-term average emission rate of 413 ng/J (0.96 lb/million Btu), for example, would decrease to 456 ng/J (1.06 lb/million Btu) heat input. Thus, the conservative nature of the assumptions included in the analysis is more than sufficient to account for whatever small influence lot size has on the variability in SO_2 emissions resulting from coal combustion. Therefore, the maximum expected emission rates presented in Table 5-2 represent the emission limits that could be achieved by combustion of low sulfur coal in industrial-commercial-institutional steam generating units.

One of the concerns that must be addressed if standards are based on the use of low sulfur coal is the availability of such coals. If the low sulfur coals upon which the standards are based are not generally or widely available, many industrial-commercial-institutional steam generating units would be unable to comply with such standards through the use of low sulfur coals. Under these circumstances, operators of these steam generating units would be forced to employ alternative measures to reduce SO_2 emissions, such as the use of FGD systems. Thus, the impacts associated with the standards could be greater or more severe than those envisioned in developing the standards. It is important, therefore, to consider the availability of low sulfur coals in determining the emission rates that can be achieved by the use of low sulfur coals.

Coal-fired utility steam generating units currently consume about 85 percent of all the coal combusted in steam generating units in the United States. Utility steam generating units generally negotiate long-term contracts to secure coal supplies. Most operators of industrial-commercial-institutional steam generating units, on the other hand, typically secure coal supplies from the "spot" market. For these reasons, large coal mines and large coal companies are primarily oriented to supply utility customers, and will undertake substantial capacity expansions or will invest in coal cleaning facilities in response to utility coal demands.

Large coal mines and companies will not do the same for industrial-commercial-institutional steam generating units, however, because their fuel demand is small in relation to utility demand and they do not typically engage in long-term contracts. Hence, much of the industrial-commercial-institutional coal market is supplied by excess stocks available through the spot market from companies that provide coal to utilities. Therefore, standards for industrial-commercial-institutional steam generating units based on the use of low sulfur coals must reflect the coals that are currently available in existing coal markets.

The promulgation of new source performance standards (40 CFR Part 60 Subpart D) for steam generating units of more than 73 MW (250 million Btu/hour) heat input in 1971 created a demand by utilities and large industrial-commercial-institutional steam generating units for low sulfur coal that can achieve an emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input or less. Over half of the steam generating units currently complying with these standards do so by the use of low sulfur coal. In response to this demand, coal markets have developed that are able to supply coals with a sulfur content of 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input or less throughout the nation. While lower sulfur coals are available in some areas, they are not widely available throughout the United States. In addition, demand for coal by industrial-commercial-institutional steam generating units is not sufficient to significantly alter this coal supply situation. Consequently, an SO_2 emission limit included in standards of performance based on the use of low sulfur coals for industrial-commercial-institutional steam generating units should be no lower than 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input.

5.2 LOW SULFUR OIL

As discussed above in "Selection of Demonstrated Emission Control Technologies," the use of low sulfur oil is considered demonstrated for the purpose of developing standards of performance for oil-fired industrial-commercial-institutional steam generating units. Low sulfur oils include both those with naturally occurring low sulfur content and those that have had sulfur removed by hydrodesulfurization techniques (HDS).

Unlike solid fuels such as coal, which have their sulfur-bearing constituents unevenly distributed because of geological and physical properties, sulfur constituents in fuel oil are not locked in place and, therefore, are distributed more evenly throughout the fuel. Moreover, other factors such as refining techniques, storage and transportation methods, and fuel handling at the steam generating unit site serve to make fuel oils relatively homogeneous with respect to fuel sulfur content. Thus, there is little variability in SO_2 emissions resulting from the combustion of a specific fuel oil.

Table 5-3 summarizes the SO_2 emission rates associated with the combustion of the various types of oils discussed in "Selection of Demonstrated Emission Control Technologies." The emission rates that can be achieved with low sulfur oils range from 129 to 344 ng SO_2/J (0.3 to 0.8 lb SO_2/million Btu) heat input. Standards of performance limiting SO_2 emissions from new, modified, and reconstructed industrial-commercial-institutional steam generating units based on the use of low sulfur oil, therefore, could reduce emissions of SO_2 to these levels or less.

5.3 COMBUSTION MODIFICATION AND FLUE GAS DESULFURIZATION

The combustion modification and flue gas desulfurization (FGD) technologies which are considered demonstrated for the purpose of developing standards of performance for industrial-commercial-institutional steam generating units are: fluidized bed combustion (FBC), lime spray drying, lime/limestone wet scrubbing, dual alkali wet scrubbing, and sodium wet scrubbing. All of these technologies have been applied to coal-fired industrial-commercial-institutional steam generating units. Only sodium wet scrubbing, however, has been applied to oil-fired industrial-commercial-institutional steam generating units. Fluidized bed combustion and lime spray drying have not been applied to oil-fired units due to the "sticky" nature of the fly ash produced from oil combustion, which could interfere with the operation of particulate matter control devices, generally fabric filters, which are an integral part of FBC and lime spray drying systems. Lime/limestone and dual alkali wet scrubbing FGD systems have not been applied to oil-fired steam generating units due primarily to non-competitive economics. There are no technical barriers, however, to successful application of lime/limestone and dual alkali FGD systems to oil-fired steam generating units.

TABLE 5-3. EMISSION RATES FOR OIL COMBUSTION

Oil Type	SO_2 Emissions ng SO_2/J (lb SO_2/million Btu)
Very Low Sulfur	129 (0.3)
Low Sulfur	344 (0.8)
Medium Sulfur	688 (1.6)
High Sulfur	1,290 (3.0)

5.3.1 Fluidized Bed Combustion

The combustion modification technology that is considered a demonstrated SO_2 emission control technology is the use of fluidized bed combustion (FBC). The system parameters that influence SO_2 removal efficiency in FBC units include the calcium-to-sulfur (Ca/S) ratio (the amount of calcium added per unit of sulfur in the fuel, on a molar basis); the solids recycle ratio (the amount of entrained solids returned to the combustion zone, on a weight basis); the gas-phase residence time (the ratio of expanded bed height to the superficial gas velocity); the sorbent (i.e., limestone) particle size; the sorbent reactivity; the fuel ash alkalinity; and the amount of freeboard (the space between the top of the bed and the point at which the flue gas exits the combustion unit). Each parameter also affects the sorbent utilization.

Westinghouse Research and Development Center has developed a model which projects sorbent requirements to attain certain levels of SO_2 removal efficiency. This is a simplified model for fluidized bed desulfurization which makes projections using kinetic rate constants developed from laboratory thermogravimetric data. For limestone with medium reactivity and an approximate 500 μm particle size, the model projects increases in SO_2 removal efficiency from about 40 percent to about 95 percent as the Ca/S ratio increases from 2 to 6.

The effect of varying the Ca/S ratio on SO_2 removal was examined during a 16-day parametric test at site A. Certified continuous SO_2 emission monitors were used for data collection on the outlet of the FBC system, and periodic sampling and analysis of feed coal was performed at the inlet in accordance with Reference Method 19A. This two-stage FBC unit had a heat input capacity of 26 MW (88 million Btu/hour) and burned a bituminous coal with a sulfur content of 2,910 ng SO_2/J (6.8 lb SO_2/million Btu). The unit load ranged from 46 to 79 percent of full load and averaged 60 percent. Solids recycle was not employed. As the Ca/S ratio increased from 0.5 to 3.2, the SO_2 removal efficiency increased from 55 to 89 percent.

The effect of varying the solids recycle ratio was examined during tests conducted at the Babcock & Wilcox Co. 1.8 m x 1.8 m (6 ft x 6 ft) FBC test unit. This FBC had a heat input capacity of about 7 MW (24 million Btu/hour). At a Ca/S ratio of 2.5 to 2.9, with no solids recycle, the SO_2 removal efficiency was about 70 percent. For the same Ca/S ratio and a solids recycle ratio of 1.0, the SO_2 removal efficiency increased to approximately 85 percent.

To assess the performance of FBC units, general information concerning the overall long-term performance of this technology was obtained from two sites. Site B was a bubbling bed FBC unit with a heat input capacity of 50 MW (171 million Btu/hour). This FBC unit burned bituminous coal with an average sulfur content of 2,150 ng SO_2/J (5.0 lb SO_2/million Btu). During a 680-day period, the unit operated with a system reliability of 93 percent. The percent removal of SO_2 for the entire 680 days could not be accurately determined because of two extended periods of continuous emission monitor malfunction.

However, during a 30-day period within this 680-day period, when the uncertified continuous emission monitors were functioning, the SO_2 removal of the unit ranged from 55 to 93 percent and averaged 82 percent. It should be noted that the FBC unit was required under State regulations to reduce SO_2 emissions by only 76 percent to achieve an emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu). During this 30-day period, the system was operated at a unit load ranging from 51 to 83 percent of full load and averaging 71 percent; the Ca/S ratio ranged from 0.9 to 3.0 and averaged 2.4. The system reliability for the 30 days was greater than 99 percent.

Site C was a bubbling bed FBC unit with a heat input capacity of 23 MW (80 million Btu/hour). This unit burned bituminous coal with a sulfur content of 470 ng SO_2/J (1.1 lb SO_2/million Btu). During a 416-day period, the unit operated with a system reliability of 92 percent. The system was operated at about 45 percent of full load during this period. It should be noted that the FBC unit was scheduled to be out of service for approximately 95 days during this period for inspection, maintenance, and testing of a stand-by boiler. The instrument technicians were not trained in the operation and maintenance of the continuous emission monitors until the latter part of the 416-day period. Reliable SO_2 emissions data were, therefore, not available for the entire 416 days, even though the monitors were certified. However, during a 67-day period within the 416-day period, when the continuous SO_2 emission monitor was properly maintained and operated, the percent SO_2 removal ranged from 74 to 95 percent and averaged 86 percent. The unit was required under State regulations to reduce SO_2 emissions by 70 percent. The unit load during this period ranged from 43 to 77 percent of full load and averaged 56 percent. The unit had a system reliability of 97 percent during the 67 days. The Ca/S ratio could not be accurately determined because the coal and limestone feed rate measuring devices were inaccurate. Solids were not recycled during this period.

In addition to the information outlined above, SO_2 emission data were obtained from five sites to further assess the performance and emissions reduction potential of FBC systems. These data consist of four short-term tests and two long-term tests.

The first short-term test was conducted over a 2-day period at site A described above using certified continuous monitors to measure SO_2 emissions at the FBC outlet. Feed coal was periodically sampled and analyzed at the inlet in accordance with Reference Method 19A. The FBC system burned a bituminous coal with a sulfur content of 2,910 ng SO_2/J (6.8 lb SO_2/million Btu). The unit load ranged from 57 to 60 percent of full load during the test and averaged 59 percent.

The FBC unit was operated at a Ca/S ratio ranging from 2.4 to 3.3 with an average of 2.8. Solids recycle was not used. During the testing period, the SO_2 removal of the system ranged from 53 to 94 percent and averaged 84 percent.

The second short-term test, conducted at site B described above, was a compliance test consisting of three 65-minute test periods using Reference Method 6 for SO_2 emissions measurements. (Certified continuous monitors were not available at the plant at the time of testing.) The FBC unit burned bituminous coal with a sulfur content of 2,450 ng SO_2/J (5.7 lb SO_2/million Btu). During each of the three testing periods, the system was operated at 100 percent of full load. Solids were recycled at an unknown rate.

The Ca/S ratio was maintained at approximately 2.7 for the first two testing periods and was increased to about 2.8 for the third testing period. The SO_2 removal for the three testing periods was 72, 81, and 81 percent, respectively. The FBC unit was required under State regulations to reduce SO_2 emissions by 79 percent to achieve an emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu).

The third test was conducted at site D, which was a large pilot plant operated to demonstrate the feasibility of FBC technology for utility-type applications. Continuous SO_2 emission monitors were used for data collection on the outlet of the system. Feed coal was periodically sampled and analyzed at the inlet in accordance with Reference Method 19A. The bubbling bed FBC unit had a heat input capacity of 59 MW (200 million Btu/hour) and burned bituminous coal. Only the average Ca/S ratio for each testing period was reported.

The duration of the first testing period at site D was 15 hours. During this period, the feed coal sulfur content was 3,270 ng SO_2/J (7.6 lb SO_2/million Btu). The unit load averaged 77 percent of full load. Solids were not recycled during this test period. The FBC system was operated at an average Ca/S ratio of about 3.0. Sulfur dioxide removal ranged from 75 to 91 percent and averaged 87 percent.

The duration of the second testing period was 12 hours. The sulfur content of the feed coal was 3,140 ng SO_2/J (7.3 lb SO_2/million Btu). During this period, the unit load averaged 75 percent of full load. Solids were not recycled. The FBC unit was operated at an average Ca/S ratio of 3.9 and achieved an average 95 percent SO_2 removal.

The duration of the third testing period was 12 hours. Feed coal with a sulfur content of 2,880 ng SO_2/J (6.7 lb SO_2/million Btu) was burned. The unit load averaged 80 percent of full load. During this period, the solids recycle ratio was 1.5. The average Ca/S ratio for this period was approximately 3.0. Sulfur dioxide removal averaged 98 percent.

The duration of the fourth testing period was 10 hours. The sulfur content of the feed coal was 3,050 ng SO_2/J (7.1 lb SO_2/million Btu). During this period, the FBC unit was operated at about 76 percent of full load. The solids recycle ratio was 1.5. The system operated at an average Ca/S ratio of about 2.9. Sulfur dioxide removal ranged from 76 to 99 percent and averaged 97 percent.

It should be noted that this FBC unit has a high freeboard zone. The high freeboard results in increased flue gas and sorbent contact time and, thus, contributes to the high SO_2 removal efficiencies achieved by this FBC system.

The fourth test was a compliance test conducted at site E. The test consisted of three 1-hour runs, and Reference Method 6 was used for SO_2 emissions measurements. This bubbling bed FBC unit had a heat input capacity of 30 MW (102 million Btu/hour) and burned bituminous coal with a sulfur content of 2,618 ng SO_2/J (6.1 lb SO_2/million Btu). The unit was operated at 72 percent of full load during the test. For the three test runs, the percent SO_2 removal was 89, 95, and 85 percent. The Ca/S ratios used to achieve these levels of removal were not available.

The first long-term test was conducted over a 30-day period at site C described above. Certified continuous SO_2 emission monitors were used for data collection on the outlet of the system. The unit burned bituminous coal with a sulfur content of 470 ng SO_2/J (1.1 lb SO_2/million Btu). During the test, the unit load ranged from 43 to 60 percent of full load and averaged 51 percent. The system operated at greater than 99 percent reliability during the test.

The Ca/S ratio could not be accurately determined because the coal and limestone feed rate measuring devices were inaccurate. Solids were not recycled during the test. Sulfur dioxide removal ranged from 81 to 95 percent and averaged 90 percent.

The second long-term test was conducted over a 25-day period at site E described above. Certified continuous SO_2 emission monitors were used for data collection on the outlet of the system. The unit burned bituminous coal with a sulfur content of 1,891 ng SO_2/J (4.4 lb SO_2/million Btu).

Sulfur dioxide removal ranged from 78 to 95 percent during the test and averaged 87 percent. It should be noted that this unit was only required under existing State regulations to reduce SO_2 emissions by 73 percent while burning this coal, to meet an emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu).

Several vendors of FBC units were also contacted regarding the performance capabilities of new FBC units. One vendor indicated that although SO_2 emissions guarantees are given on a case-by-case basis, depending on fuel type and limestone reactivity, FBC units can be designed to achieve well above 90 percent SO_2 removal. This would require a reactive limestone and increased limestone feed rates. However, FBC units can be designed to accommodate the increased solids loading with no adverse effects on system reliability. Another vendor stated that their circulating bed FBC units could reduce SO_2 emissions by 90 percent when burning coal containing 3 weight percent sulfur and operating at a Ca/S ratio of 2.0.

In light of the above information, there appear to be no technical barriers to achieving greater than 90 percent SO_2 removal with an FBC system on a sustained basis at higher (90 percent) reliabilities.

5.3.2 Lime Spray Drying

The first FGD technology that is considered to be demonstrated is lime spray drying. The two system parameters that have a major influence on SO_2 removal efficiency in lime spray drying systems are the reagent ratio (amount of reagent added per unit of inlet SO_2) and the approach to saturation temperature. The choice of particulate matter (PM) control device will also influence overall system SO_2 removal. Other parameters such as solids recycle, inlet SO_2 concentration, inlet flue gas temperature, and PM loading have less effect on SO_2 removal, but may have an impact on reagent utilization.

To assess the performance of lime spray drying applied to coal-fired industrial-commercial-institutional steam generating units, general information concerning the overall long-term performance of this technology was obtained from three sites. At the first site, the lime spray drying system operated on a coal-fired spreader stoker steam generating unit with a heat input capacity of 34 MW (115 million Btu/hour). The steam generating unit burned bituminous coal with a sulfur content that ranged from 400 ng SO_2/J (0.93 lb SO_2/million Btu) to 850 ng SO_2/J (1.99 lb SO_2/million Btu), and averaged 570 ng SO_2/J (1.32 lb SO_2/million Btu). The steam generating unit load was maintained near 100 percent. The lime spray drying system employed a fabric filter downstream of the spray dryer for particulate matter emission control. Information on reagent ratio and the approach to saturation temperature was not available. During a period of over 450 days, the lime spray drying system operated at an average SO_2 removal level of 60 percent with a system reliability of 93 percent.

During a different period at this same site, the steam generating unit burned bituminous coal with a sulfur content that ranged from 1,300 ng SO_2/J (3.03 lb SO_2/million Btu) to 3,580 ng SO_2/J (8.33 lb SO_2/million Btu) and averaged 1,960 ng SO_2/J (4.55 lb SO_2/million Btu). The steam generating unit load was again maintained near 100 percent. Over a 555-day period, the lime spray drying system operated at an average 70.4 percent SO_2 removal efficiency and a reliability level of 78 percent.

At the second site, the lime spray drying system operated on a pulverized coal-fired steam generating unit with a heat input capacity of 69 MW (235 million Btu/hour). The steam generating unit burned bituminous coal with a sulfur content that ranged from 330 ng SO_2/J (0.76 lb SO_2/million Btu) to 420 ng SO_2/J (0.98 lb SO_2/million Btu) and averaged 390 ng SO_2/J (0.91 lb SO_2/million Btu). The steam generating unit load varied from 71 to 91 percent of full load and averaged 82 percent. The lime spray drying system operated at a reagent ratio that varied from 1.3 to 1.5 and averaged 1.4. Information on the approach to saturation temperature was not available. The system employed a fabric filter downstream of the spray dryer for particulate matter emissions control. Over a 795-day period, the lime spray drying system operated at an average 75.8 percent SO_2 removal and a reliability level of 83 percent.

At the third site, the lime spray drying system serviced a coal-fired spreader stoker steam generating unit with a heat input capacity of 69 MW (235 million Btu/hour). The steam generating unit combusted bituminous coal with a sulfur content that ranged from 2,280 ng SO_2/J (5.30 lb SO_2/million Btu) to 2,470 ng SO_2/J (5.75 lb SO_2/million Btu) and averaged 2,300 ng SO_2/J (5.35 lb SO_2/million Btu). The steam generating unit load varied from 53 to 71 percent of full load and averaged 61 percent. The lime spray drying system operated at an average reagent ratio of 1.07 and employed a fabric filter for particulate matter emissions control. Information on the approach to saturation temperature was not available. Over an 864-day period, the system operated at an average 79.6 percent SO_2 removal efficiency and a reliability level of 45 percent.

In addition to the general information outlined above, SO_2 emission data were obtained from six sites to assess the performance of lime spray drying systems. These data consist of four short-term and three long-term tests. The first short-term test was a compliance test conducted over approximately 2 hours using Reference Method 6 for SO_2 emission measurements. The test results were used to determine compliance with applicable SO_2 emission regulations for the new lime spray drying system shortly after system startup and commissioning. The lime spray drying system treated flue gas from a pulverized coal-fired steam generating unit with a heat input capacity of 82 MW (280 million Btu/hour). The steam generating unit burned bituminous coal with an average sulfur content of 1,430 ng SO_2/J (3.33 lb SO_2/million Btu). The steam generating unit operated at 100 percent of full load.

The SO_2 absorber was operated at an average 19°C (35°F) approach to saturation temperature. Reagent ratio during the test was not recorded. The system employed a fabric filter downstream of the spray dryer for particulate matter collection. The SO_2 removal efficiencies during six sampling periods were 68.5, 73.3, 75.4, 76.0, 76.9, and 77.5 percent, for an overall average of 74.5 percent.

The second short-term test was also conducted over approximately 2 hours using Reference Method 6 for SO_2 emission measurements. The lime spray drying system treated flue gas from a coal-fired spreader stoker steam generating unit with a heat input capacity of 34 MW (115 million Btu/hour). This unit was fired with a mixture of bituminous coal with an average sulfur content of 2,530 ng SO_2/J (5.89 lb SO_2/million Btu) and oil with an average sulfur content of 410 ng SO_2/J (0.96 lb SO_2/ million Btu). The steam generating unit operated at approximately 75 percent of full load. Of the total heat input to the unit, 94.2 percent was derived from coal and the remainder from oil.

The spray dryer was operated at an average 14°C (25°F) approach to saturation temperature. Reagent ratio was not recorded during the test. A fabric filter was used downstream of the spray dryer for particulate matter control. SO_2 removal efficiencies achieved during the six sampling periods were 90.1, 90.3, 91.6, 92.3, 93.6, and 96.7 percent, for an overall average of 92.4 percent.

A series of three short-term performance tests was conducted at a third site. The three tests were performed over 8 hours using Reference Method 6 for SO_2 emission measurements. The steam generating unit at this site was a coal-fired spreader stoker unit with a heat input capacity of 69 MW (235 million Btu/hour). The steam generating unit fired bituminous coal with an average sulfur content of 2,190 ng SO_2/J (5.09 lb SO_2/million Btu). During the three test periods, the steam generating unit load was maintained at 35, 70, and 82 percent of full load.

The approach to saturation temperature for this lime spray drying system was maintained at 13°C (23°F). A fabric filter was employed at this site downstream of the spray dryer for particulate matter control. The reagent ratio was varied during each testing period to obtain the following results: 79.7 percent SO_2 removal at 0.6 reagent ratio; 89.9 percent SO_2 removal at 1.4 reagent ratio; and 95.6 percent SO_2 removal at 1.9 reagent ratio.

A second series of short-term performance tests was also conducted over a 4-hour period at this same site. Reference Method 6 was used for SO_2 emission measurements as in the above tests. For this test series, the steam generating unit fired bituminous coal with an average sulfur content of 2,840 ng SO_2/J (6.61 lb SO_2/million Btu). During the test period, the steam generating unit operated at loads that varied between 50 and 74 percent of full load.

Both the reagent ratio and approach to saturation temperature were varied during the testing. At a 17°C (30°F) approach to saturation temperature, SO_2 removal efficiencies of 64, 78, and 74 percent were achieved with reagent ratios of 1.1, 1.2, and 1.3, respectively. Lowering the approach to saturation temperature to 12°C (22°F) resulted in 80.8 percent SO_2 removal at a reagent ratio of 1.0. At a 11°C (20°F) approach to saturation temperature, SO_2 removal efficiencies of 83, 87, 90, and 96 percent were achieved with reagent ratios of 1.1, 1.2, 1.3, and 1.6, respectively.

The fourth short-term test was a compliance test conducted over three 1-hour periods using Reference Method 6 for SO_2 emission measurements. The lime spray drying system treated flue gas from a pulverized coal-fired steam generating unit with a heat input capacity of 69 MW (235 million Btu/hour). The steam generating unit burned bituminous coal with an average sulfur content of 410 ng SO_2/J (0.96 lb SO_2/million Btu). The steam generating unit operated at 100 percent of full load.

The spray dryer was operated at an approach to saturation temperature that varied between 28° and 39°C (50° and 70°F). The reagent ratio was approximately 3.3. The system employed a fabric filter downstream of the spray dryer for particulate matter collection. The SO_2 removal efficiencies during the three test periods were 95.8, 96.8, and 97.0 percent, for an overall average of 96.6 percent.

The first long-term test was conducted over a 30-day period using Reference Method 19A continuous SO_2 emission monitors for data collection on both the inlet and outlet of a lime spray drying system. The system at this site treated flue gas from a coal-fired industrial spreader stoker steam generating unit with a heat input capacity of 44 MW (150 million Btu/hour). The sulfur content of the bituminous coal fired by the steam generating unit ranged from 1,040 ng SO_2/J (2.42 lb SO_2/million Btu) to 1,830 ng SO_2/J (4.25

lb SO_2/million Btu) and averaged 1,330 ng SO_2/J (3.09 lb SO_2/million Btu). The steam generating unit load varied from 53 to 68 percent of full load.

The lime spray drying system employed a fabric filter for particulate matter control downstream of the spray dryer. Reagent ratio and approach to saturation temperature were not recorded during the test. Approximately 10 to 20 percent of the flue gas from the steam generating unit was bypassed around the FGD system. During the 23 days on which SO_2 data were collected, the overall SO_2 removal efficiency ranged from 56 to 82 percent and averaged 70 percent. Numerous operating problems were encountered with the steam generating unit and the lime spray drying system during the first 17 days of data collection. These operational problems were corrected and the lime spray drying system operated in a normal manner during the final 6 days of testing. The overall performance level averaged 78.5 percent SO_2 removal during these last 6 days of testing.

Assuming a 10 percent flue gas bypass, the SO_2 removal efficiency across the lime spray drying system would be about 78 and 87 percent during the 23-day and 6-day periods, respectively. Assuming a 20 percent flue gas bypass, the SO_2 removal efficiency across the lime spray drying system would be about 88 and 98 percent during the 23-day and 6-day periods, respectively. During the entire CEMS data collection period, the lime spray drying system operated at an average reliability level of 73 percent. For the last 6 days of testing, the lime spray drying system reliability was 97 percent.

The second long-term test was conducted over 28 days using Reference Method 6B for SO_2 emission measurements on both the inlet and outlet of a lime spray drying system. The steam generating unit at this site was a coal-fired industrial spreader stoker steam generating unit with a heat input capacity of 69 MW (235 million Btu/hour). The steam generating unit fired subbituminous coal with a sulfur content that ranged from 2,200 ng SO_2/J (5.12 lb SO_2/million Btu) to 2,350 ng SO_2/J (5.47 lb SO_2/million Btu) and averaged 2,280 ng SO_2/J (5.30 lb SO_2/million Btu). The steam generating unit load ranged from 53 to 71 percent.

The spray dryer was operated at a reagent ratio of 1.1 and an approach to saturation temperature that varied between 9° and 16°C (17° and 29°F) and averaged 15°C (27°F). The system included a fabric filter downstream of the spray dryer for particulate matter control. During the 28 days over which data were collected, SO_2 removal efficiency ranged from 82.2 to 92.1 percent, for an average of 86.6 percent. The lime spray drying system operated at a reliability level of 75 percent, excluding an electrical problem not related to the FGD system.

The third long-term test was conducted over approximately 12 days using Reference Method 19A continuous SO_2 emission monitors for data collection on both the inlet and outlet of a lime spray drying system. The system serviced a utility pulverized coal-fired steam generating unit with a heat input capacity of approximately 300 MW (1,025 million Btu/hour). Although utility steam generating units are significantly different in design and operation than their smaller industrial-commercial-institutional counterparts, the design and operation of lime spray drying systems for these two applications are essentially the same. For this reason, utility steam generating unit lime spray drying system performance is directly applicable to industrial-commercial-institutional steam generating units. The sulfur content of the bituminous coal burned during the test ranged from 2,330 ng SO_2/J (5.43 lb SO_2/million Btu) to 2,580 ng SO_2/J (6.01 lb SO_2/million Btu) and averaged 2,510 ng SO_2/J (5.85 lb SO_2/million Btu). The steam generating unit operated at an average of 82 percent of full load.

The spray dryer at the utility steam generating unit was operated at an average reagent ratio of 1.33 and an approach to saturation temperature which averaged 10°C (18°F). The system included a fabric filter downstream of the spray dryer for particulate matter control. During the 174-hour period during which continuous SO_2 emission monitoring data were collected, SO_2 removal efficiency averaged 88.1 percent. During the test period, the lime spray drying FGD system operated at a reliability level of approximately 85 percent.

The SO_2 removal performance data from the last 6 days of testing at the second long-term test site discussed above were analyzed to determine their variability [i.e., relative standard deviation (RSD) and autocorrelation (AC)] using an AR(1) time series statistical model as discussed earlier. These data were selected for analysis because they represent the longest period of Reference Method 19A continuous SO_2 emission monitoring data for a lime spray drying system operating at normal conditions on an industrial steam generating unit.

The 24-hour RSD and AC values of the data were found to be 18.6 percent and 0.18, respectively, based on controlled SO_2 emissions. Using a 30-day rolling average to determine performance (i.e., percent reduction in emissions), the AR(1) model was used to project the maximum expected variation in performance, assuming this maximum variation would only be exceeded once in ten years. This once in ten years maximum expected variation in performance on a 30-day rolling average basis was found to be less than 3 percentage points.

Thus, SO_2 removal efficiency can be expected to vary by less than 3 percentage points above and below the mean SO_2 removal efficiency using a data averaging period of 30 days. Consequently, to ensure that SO_2 removal efficiency for a given lime spray drying system is consistently above a minimum performance level, the system should be operated at a long-term average performance level 3 percentage points above the minimum performance level. If the system is operated in this manner, SO_2 removal performance would be expected to fall below the minimum level only once in a ten-year period. It follows, therefore, that a lime spray drying system should be operated at a long-term average performance level of 93 percent or above to ensure that the SO_2 emissions reduction for the system is consistently at or above 90 percent.

All of the long-term performance data discussed above for lime spray drying systems range from 60 to 80 percent reduction in SO_2 emissions. The short-term performance data, however, indicate that lime spray drying systems are capable of achieving performance levels in excess of 93 percent reduction in SO_2 emissions.

The effect of operation at such a high level of performance on system reliability is not clear. A review of the available data shows an apparent decrease in system reliability with increased system performance. However, an examination of the reasons for decreased reliability shows that failures were generally not the result of increased system stress, such as increased solids flow rates resulting from higher reagent ratios or increased solids recycle rates due to operation at higher performance levels. In fact, most failures examined to date on one existing industrial lime spray drying system appear to have been preventable. Improved operating and maintenance procedures, maintaining an inventory of spare parts, and having parallel or redundant key process components would have prevented most failures. Conversations with the vendor of this system indicate that the majority of industrial systems sold to date do not have the spare components inventory and preventable maintenance program necessary to maintain high system reliability.

This vendor believes high reliability can be achieved at high performance levels and is prepared to offer a 95 percent reliability guarantee on lime spray drying systems, irrespective of coal sulfur content and SO_2 removal guarantees. Such a guarantee, however, would require the customer to maintain a spare components inventory and follow the vendor's recommended preventive maintenance program.

As a result, there appear to be no technical barriers to achieving greater than 90 percent SO_2 removal with a lime spray drying system on a sustained basis at high (90 percent) reliabilities.

5.3.3 Lime/Limestone Wet Scrubbing

The second FGD technology that is considered to be demonstrated is lime/limestone wet scrubbing. The five system parameters that have a major influence on SO_2 removal efficiency in lime and limestone FGD systems are the contact area in the scrubber (determined primarily by scrubber type and internal design), liquid-to-gas ratio, calcium-to-sulfur ratio, pH, and the concentration of mass transfer additives in the absorber feed liquor. The data gathered to assess the performance of lime and limestone wet scrubbing applied to coal-fired industrial-commercial-institutional steam generating units consist of a short-term and a long-term emission test.

The short-term test was a performance test on a lime wet scrubbing system conducted over three 1-hour periods using Reference Method 6 for SO_2 emission measurements. The lime wet scrubbing system serviced two coal-fired spreader stoker steam generating units with heat input capacities of approximately 18 and 53 MW (60 and 180 million Btu/hour). The steam generating units fired bituminous coal with an average sulfur content of 2,670 ng SO_2/J (6.2 lb SO_2/million Btu). The steam generating unit load ranged from approximately 75 to 84 percent of full load.

The SO_2 absorber design in this system was based on a configuration consisting of a curtain of chains attached to the wall of a rotating kiln. The lime slurry flow through the horizontal kiln was countercurrent to the flue gas flow. No lime slurry recycle was employed; instead, the spent slurry was sent directly to an industrial wastewater pretreatment plant after passing through the kiln. This scrubber operated at a liquid-to-gas ratio of 67 ℓ/m^3 (0.5 gallon/1,000 actual ft^3) and a feed slurry pH of 12 to 13. No mass transfer additive was used during this test, and the calcium-to-sulfur ratio was not recorded.

During the performance test, SO_2 emissions were measured at the outlet of the FGD system but not at the inlet to the system. Thus, SO_2 removal efficiency across the FGD system could not be calculated directly. However, coal fed to the steam generating units was sampled and analyzed during the performance test period. The three areas in this system where sulfur in the feed coal could be removed are with the bottom ash from the steam generating unit, with the fly ash captured by the particulate matter control device, and in the FGD system. It is unlikely that significant amounts of sulfur would be removed in the first two areas because of the low alkalinity generally associated with ash from bituminous coal. Consequently, almost all of the SO_2 removal would be by the wet lime scrubbing system.

Based on the sulfur and heat content of the feed coal, the average SO_2 removal efficiency across the entire plant (including steam generating units, particulate matter control devices, and wet lime scrubbing system) was 96 percent during the testing period.

The reliability of this system over several years of operation was reported by the operator to be 95 percent. The long-term average steam generating unit loads were reported to be 75 percent for the larger unit and 50 percent for the smaller unit, which translates to an average FGD system load of approximately 71 percent.

The long-term test was conducted on a lime/limestone wet scrubbing system using continuous SO_2 emission monitors for data collection at both the inlet and outlet of the FGD system. Data were collected for a 30-day period while the system used a limestone reagent and for 29 days during a 55-day period while the system used a lime reagent.

This scrubbing system serviced six coal-fired stoker steam generating units with a total rated capacity of 62 MW (210 million Btu/hour). The wet scrubbing system was designed to remove approximately 80 percent of inlet SO_2 from combustion of a Midwestern bituminous coal having a sulfur content between approximately 2,370 ng SO_2/J (5.5 lb SO_2/million Btu) and 3,140 ng SO_2/J (7.3 lb SO_2/million Btu) using either lime or limestone reagent. The SO_2 absorber was a vertical tower consisting of two inverted venturi scrubbing stages. A unique feature of this system was the maintenance of constant liquid and gas flow rates to the SO_2 absorber. This was done to minimize the need for operator attention and response to changing process conditions. Constant flows were achieved by fixing the lime slurry feed pumps and induced draft fan upstream of the absorber at preset levels. At reduced steam generating unit load conditions, tempering air was added via a make-up stack upstream of the induced draft fan to offset reduced flue gas flow from the steam generating units. The result was that gas flow to the absorber was independent of load conditions, but SO_2 inlet concentration varied with load.

During the 29-day data collection period when lime was used as the reagent in the wet scrubbing system, the sulfur content of the bituminous coal fired averaged 2,150 ng SO_2/J (5.0 lb SO_2/million Btu), with a range of 1,890 to 2,490 ng SO_2/J (4.4 to 5.8 lb SO_2/million Btu). During this period the steam generating unit load varied from 34 to 65 percent of full load. The pH of the feed slurry averaged 7.3 during the testing period and ranged on a daily average basis from 4.3 to 8.5. No mass transfer additives were used during this test. The liquid-to-gas ratio and calcium-to-sulfur ratio were not recorded during the test period. Over the 29-day data collection period, the SO_2 removal efficiency ranged from 86.7 to 96.0 percent and averaged 91.5 percent. During the entire 55-day test period, the lime wet scrubbing FGD system operated at a reliability level of over 91 percent.

During the 30-day test period when limestone was used as the reagent in the wet scrubbing system, the sulfur content of the bituminous coal burned averaged about 2,150 ng SO_2/J (5.0 lb SO_2/million Btu). During this period the steam generating unit load varied from 30 to 67 percent of full load. The pH of the feed slurry averaged 5.0 during the testing period and ranged on a daily average basis from 4.6 to 5.5. Adipic acid was used as the mass transfer agent during this test. It was added at an average rate of 4 kg/hour (9 lb/hour), which resulted in an average concentration of 2,260 parts per million (ppm) in the feed slurry. The liquid-to-gas ratio and calcium-to-sulfur ratio were not recorded during the test period. Over the 30-day data collection period, the SO_2 removal efficiency ranged from 90.0 to 97.4 percent and averaged 94.3 percent. The system operated at a reliability level of 94 percent during the test period.

Lime and limestone wet scrubbing FGD SO_2 removal efficiencies at this site were insensitive to changes in steam generating unit load over the range observed. On utility FGD systems using lime or limestone, some decrease in SO_2 removal performance has been observed with increased SO_2 inlet concentration or increased load. To overcome full load effects, the liquid-to-gas ratio, reagent ratio, or feed slurry pH could be adjusted.

At this site, increases in SO_2 inlet concentrations and increased load occur simultaneously. The FGD system at this site, however, was not designed to make adjustments in liquid-to-gas ratio, reagent ratio, or feed slurry pH. Thus, the experience gained from the tests discussed above shows that 91.5 and 94.3 percent SO_2 removals on high sulfur coal using lime and limestone reagents, respectively, have been reliably and consistently achieved on an industrial steam generating unit operated at normal, but less than maximum, load.

New lime or limestone wet scrubbing systems could be designed and operated to maintain these high levels of performance by adjusting the liquid-to-gas ratio upward at higher loads. In addition, a spray tower or turbulent contactor absorber would likely be selected as the absorber vessel in place of the two-stage venturi scrubber to provide sufficient mass transfer area and gas residence time for increased SO_2 absorption. While this type of system would inevitably require more operator attention to process fluctuations, such systems have been successfully employed on utility steam generating units and could be used on industrial-commercial-institutional steam generating units.

These long-term data for lime and limestone wet scrubbing systems were analyzed to determine their variability (i.e., RSD and AC) using an AR(1) time series statistical model as discussed earlier. The 24-hour RSD and AC values were found to be 42 percent and 0.08, respectively, based on controlled SO_2 emissions. Using a 30-day rolling average to determine performance (i.e., percent reduction in emissions), the AR(1) model was used to project the maximum expected variation in performance, assuming this maximum variation would only be exceeded once in ten years. This once in ten years maximum expected variation in performance on a 30-day rolling average basis was found to be less than 2 percentage points.

Thus, SO_2 removal efficiency can be expected to range by less than 2 percentage points above and below the mean SO_2 removal efficiency using a data averaging period of 30 days. Consequently, to ensure that SO_2 removal efficiency for a given lime or limestone wet scrubbing system is consistently above a minimum performance level, the system should be operated at a long-term average performance level 2 percentage points above the minimum performance level. If the system is operated in this manner, SO_2 removal performance would be expected to fall below the minimum level only once in a ten-year period. It follows, therefore, that a lime or limestone wet scrubbing system should be operated at a long-term average performance level of 92 percent or above to ensure that the SO_2 emissions reduction for the system is consistently at or above 90 percent.

The long-term data presented above for lime and limestone FGD systems show SO_2 removal efficiencies of 91.5 and 94.3 percent, respectively, which are near or above the long-term average required to meet consistently a once in ten year 30-day rolling average minimum performance level of 90 percent emission reduction. Although these results were obtained at less than maximum load conditions, new systems could achieve this level of performance at full load by operating at a higher liquid-to-gas ratio. In addition, new systems would likely be equipped with a spray tower or turbulent contact absorber to provide increased mass transfer area and gas residence time for improved SO_2 absorption.

Based on these analyses of system performance and system variability, the lime wet scrubbing FGD technology is capable of reducing SO_2 emissions from coal-fired industrial-commercial-institutional steam generating units by 90 percent using a 30-day rolling average to calculate emission reductions.

5.3.4 Dual Alkali Scrubbing

The third FGD technology that is considered to be demonstrated is dual alkali wet scrubbing. The five system parameters which have a major influence on SO_2 removal efficiency in dual alkali systems are contact area in the scrubber (determined primarily by scrubber type and internal design), liquid-to-gas ratio, calcium-to-sulfur ratio, sodium-to-sulfur ratio, and pH. The data gathered to assess the performance of dual alkali scrubbing applied to coal-fired industrial-commercial-institutional steam generating units consist of four short-term and two long-term emission tests.

The first short-term test was an acceptance test conducted over three 1-hour periods using an SO_2 emission measurement method developed by the Pennsylvania Department of Environmental Resources (PADER). An acceptance test consists of a series of short-term emission measurements conducted shortly after an FGD system has been commissioned to determine whether system performance conforms to design expectations or vendor guarantees. The PADER method is similar to Reference Method 6 except that it captures and analyzes SO_3 as well as SO_2 in the flue gas; Reference Method 6 captures and analyzes only SO_2. Because SO_3 is not readily absorbed in most FGD systems, including dual alkali systems, the SO_2 removal efficiency measured with the PADER method will be slightly lower than the efficiency measured with Reference Method 6 under identical conditions.

The dual alkali wet scrubbing system at this site serviced two pulverized coal-fired steam generating units, each with a heat input capacity of 156 MW (531 million Btu/hour). Flue gas from each unit was directed to a separate SO_2 absorber. The spent scrubbing solution from each absorber was sent to a single regeneration section. This acceptance test was conducted on the first absorber serving a single steam generating unit. The steam generating unit fired bituminous coal with a sulfur content of 2,260 ng SO_2/J (5.25 lb SO_2/million Btu). The steam generating unit load was approximately 97 percent of full load.

The SO_2 absorber in this system was a vertical tower in which flue gas flowed upward through four stages of disc and doughnut baffles. Scrubbing liquor flowed countercurrent to the flue gas at a design liquid-to-gas ratio of 1,340 ℓ/m^3 (10 gallon/1,000 ft^3). The dual alkali FGD system operated at a calcium-to-sulfur molar ratio of 1.0 and a ratio of 0.065 mole of sodium (as sodium carbonate) per mole of SO_2 absorbed. The pH of the scrubbing liquor was controlled near 6.5. The SO_2 removal efficiencies were 83.3, 86.1, and 86.8 percent during the three 1-hour tests, for an average of 85.4 percent.

The second short-term test was a 3-hour acceptance test conducted on the second absorber at the same facility. The second absorber serviced a single steam generating unit operated at 93 percent of full load. All other conditions were the same except that the scrubbing liquor pH was reported to be higher than normal. The SO_2 removal efficiencies of this system were 90.5, 90.8, and 91.0 percent during the three 1-hour tests, for an average of 90.8 percent.

The overall reliability of this system (including both the first absorber, the second absorber, and a third absorber installed in the system subsequent to the acceptance tests described above) during the 12 months of 1981 was reported by the operator to be over 97 percent.

The third short-term test was a performance test conducted over three 1-hour periods using Reference Method 6 for SO_2 emission measurement. The dual alkali wet scrubbing system serviced three coal-fired stoker steam generating units with heat input capacities of 14 MW (25 million Btu/hour) for Units No. 3 and 4 and 49 MW (85 million Btu/hour) for Unit No. 5. The dual alkali system consisted of two SO_2 absorbers and a single regeneration section. During the performance test, only steam generating Units No. 3 and 5 were operated. Flue gas from Unit No. 3 was directed to Absorber A while flue gas from Unit No. 5 was directed to Absorber B. Steam generating Unit No. 3, the subject of this performance test, was fired with bituminous coal with an average sulfur content of 2,360 ng SO_2/J (5.49 lb SO_2/million Btu). The steam generating unit load was approximately 78 percent of full load. This corresponded to approximately 43 percent of the Absorber A design capacity.

The SO_2 absorber in this system was a venturi-type scrubber. The liquid-to-gas ratio was maintained near 4,700 ℓ/m^3 (35 gallon/1,000 ft^3). The pH of the scrubbing liquor averaged 6.0. The calcium-to-sulfur and sodium-to-sulfur ratios were not reported. The SO_2 removal efficiency was 85.6, 86.4, and 91.9 percent during the three 1-hour tests, for an average of 88.1 percent.

The fourth short-term test was a 3-hour performance test conducted on Unit No. 5 of the same facility immediately following the above test. Steam generating Unit No. 5 combusted the same coal as Unit No. 3 and operated at approximately 65 percent of full load. This corresponded to approximately 59 percent of the Absorber B design capacity.

Absorber B was also a venturi-type scrubber. The liquid-to-gas ratio was maintained near 5,400 ℓ/m^3 (40 gallon/1,000 ft^3). The pH of the scrubbing liquor averaged 7.1. The calcium-to-sulfur and sodium-to-sulfur ratios were not reported. The SO_2 removal efficiencies were 87.7, 96.9, and 97.9 percent during the three 1-hour tests, for an average of 94.2 percent.

The first long-term test was conducted over 17 days using continuous SO_2 emission monitors for data collection on both the inlet and outlet of the FGD system. The dual alkali wet scrubbing system at this site serviced two coal-fired spreader stoker steam generating units with heat input capacities of 40 MW (135 million Btu/hour) for Unit No. 1 and 23 MW (77 million Btu/hour) for Unit No. 3. The dual alkali system consisted of two SO_2 absorbers, each serving a separate steam generating unit, and a single regeneration section. The sulfur content of the bituminous coal received at the plant during the test averaged 1,490 ng SO_2/J (3.47 lb SO_2/million Btu) with a range of 1,340 to 1,670 ng SO_2/J (3.12 to 3.88 lb SO_2/million Btu). During the test, the steam generating units also burned oil with an average sulfur content of 320 ng SO_2/J (0.74 lb SO_2/million Btu) and a range of 270 to 370 ng SO_2/J (0.62 to 0.86 lb SO_2/million Btu), based on deliveries received during the testing period. On a thermal input basis, coal represented 92.5 percent of the fuel burned during this period for both steam generating units; the balance of the heat input was supplied by oil. Steam generating Unit No. 1, the subject of this test, operated at an average load of 67 percent of full load. The load varied between 42 and 96 percent during the testing period.

In the Unit No. 1 scrubber, flue gases flowed countercurrent to the aqueous scrubbing solution. The two streams were brought into contact by means of two absorption trays fitted with self-adjusting bubble caps. The absorber operated at a design liquid-to-gas ratio of 2,680 ℓ/m^3 (20 gallon/1,000 ft^3). The calcium-to-sulfur ratio ranged from 1.32 to 1.90 mole of calcium per mole of sulfur in the filter cake. The sodium-to-sulfur ratio varied between 0.028 and 0.05 mole of sodium carbonate (Na_2CO_3) per mole of SO_2 removed. The pH of the scrubbing liquor ranged from 5.7 to 6.5 and averaged 6.0. Over the 17-day data collection period, the SO_2 removal efficiency ranged from 87.6 to 95.2 percent and averaged 91.6 percent. During the test period, the dual alkali scrubbing FGD system operated at a reliability level of 100 percent.

The second long-term test was conducted on steam generating Unit No. 3 of the same facility shortly after the above test. Data were collected over a 24-day period using continuous SO_2 emission monitors on both the inlet and outlet of the FGD system. The fuel analysis for coal and oil burned during the test and the heat input ratio of coal and oil were the same as that for Unit No. 1. Steam generating unit load varied between 5 and 95 percent during the testing period and averaged 62 percent of full load based on coal-fired heat input capacity.

The SO_2 absorber design, liquid-to-gas ratio, calcium-to-sulfur ratio, and sodium-to-sulfur ratio were the same as that for Unit No. 3. The pH of the scrubbing liquor ranged from 4.7 to 6.5 and averaged 6.0. Over the 24-day collection period, the SO_2 removal ranged from 73.6 to 97.1 percent and averaged 92.2 percent. During the test period, the dual alkali scrubbing FGD system operated at a reliability level of 100 percent.

During both of the long-term performance tests, the SO_2 removal efficiency was insensitive to changes in steam generating unit and FGD system load over the range observed. Dual alkali wet scrubbing systems, however, operate with a scrubbing liquor sodium concentration that is greatly in excess of the theoretical amount required for SO_2 absorption. As a result, SO_2 removal performance is not mass transfer limited, but is determined by the equilibrium conditions of the scrubbing liquor. These conditions are governed primarily by the concentration of active sodium species. Consequently, increasing the SO_2 loading on the system, either by increasing the flue gas flow rate or SO_2 concentrations, would not seriously deplete excess active sodium species nor affect feed liquor pH in the short run. Thus, SO_2 removal performance will be relatively independent of load and inlet SO_2 concentration if vigorous gas-liquid contact is maintained in the absorber and the sodium-to-sulfur and liquid-to-gas ratios are maintained at a constant level.

This is verified by statistical analysis of the SO_2 performance data from the 17- and 24-day tests showing that SO_2 removal efficiency was independent of SO_2 inlet concentration. It follows, therefore, that variations in steam generating unit load would similarly not affect SO_2

removal. The 24-day test shows that 92.2 percent SO_2 removal on high sulfur coal can be reliably and consistently achieved on an industrial steam generating unit operated at normal, but less than maximum, load. A dual alkali wet scrubbing system could also operate at this level of performance under full load conditions by adjusting the reagent addition rate and scrubbing liquor feed rate upward to maintain constant sodium-to-sulfur and liquid-to-gas ratios.

These long-term data for dual alkali wet scrubbing systems were analyzed to determine their variability (i.e., RSD and AC) using an AR(1) time series statistical model as discussed earlier. The 24-hour RSD and AC values of the data were found to be 33 percent and 0.13, respectively, based on controlled SO_2 emissions. Using a 30-day rolling average to determine performance (i.e., percent reduction in emissions), the AR(1) model was used to project the maximum expected variation in performance, assuming this maximum variation would only be exceeded once in ten years. This once in ten years maximum expected variation in performance on a 30-day rolling average basis was found to be less than 2 percentage points.

Thus, SO_2 removal efficiency can be expected to vary by less than 2 percentage points above and below the mean SO_2 removal efficiency using a data averaging period of 30 days. Consequently, to ensure that SO_2 removal efficiency for a given dual alkali wet scrubbing system is consistently above a minimum performance level, the system should be operated at a long-term average performance level 2 percentage points above the minimum performance level. If the system is operated in this manner, SO_2 removal performance would be expected to fall below the minimum level only once in a ten-year period. It follows, therefore, that a dual alkali wet scrubbing system should be operated at a long-term average performance level of 92 percent or above to ensure that the SO_2 emissions reduction efficiency for the system is consistently at or above 90 percent.

The dual alkali system average performance during the second long-term test was 92.2 percent, which is equivalent to the long-term average required to meet consistently a once in ten year 30-day rolling average minimum performance level of 90 percent emission reduction. Although this performance level was achieved at a steam generating unit and FGD system load of only 62 percent, this same level of performance can be achieved by a new dual alkali wet scrubbing system at full load conditions if vigorous gas-liquid contact is maintained in the absorber and the sodium-to-sulfur and liquid-to-gas ratios are maintained at a level sufficient to provide an adequate supply of active sodium species.

Based on these analyses of system performance and system variability, the dual alkali wet scrubbing FGD technology is capable of reducing SO_2 emissions from coal-fired industrial-commercial-institutional steam generating units by 90 percent using a 30-day rolling average to calculate emission reductions.

5.3.5 Sodium Wet Scrubbing

The fourth FGD technology that is considered to be demonstrated for industrial-commercial-institutional steam generating units is sodium wet scrubbing. The three system parameters that have a major influence on SO_2 removal efficiency in sodium scrubbing systems are contact area in the scrubber (determined primarily by scrubber type and internal design), sodium-to-sulfur ratio, and pH. The data gathered to assess the performance of sodium wet scrubbing applied to coal-fired and oil-fired industrial-commercial-institutional steam generating units consist of 12 short-term emission tests, one long-term emission test, and reliability data from two sites accounting for a total of 16 sodium wet scrubbers.

A long-term emission test was conducted over a 30-day period at a coal-fired industrial-commercial-institutional steam generating unit using continuous SO_2 emission monitors for data collection on both the inlet and outlet of the scrubber. The FGD system was designed to service two coal-fired steam generating units with a total rated heat input capacity of 94 MW (320 million Btu/hour). During the test period, flue gas from only one unit, a pulverized coal-fired steam generating unit, was directed to the FGD system. The sulfur content of the subbituminous coal burned during the test ranged between 3.55 and 3.73 weight percent. This corresponded to a flue gas SO_2 concentration at the scrubber inlet that ranged from 1,980 ng SO_2/J (4.6 lb SO_2/million Btu) to 2,710 ng SO_2/J (6.3 lb SO_2/million Btu). During this period, the pulverized coal-fired steam generating unit load varied from 33 to 80 percent of full load. This corresponded to 22 to 52 percent of FGD system design capacity.

The SO_2 absorber in this system was a tray and quench liquid scrubber. Sodium hydroxide was used as the absorption reagent and was added in the form of a 50 percent solution with water at a rate of 132 ℓ/minute (35 gallon/minute). This corresponded to a sodium-to-sulfur molar ratio of approximately 27 to 1 based on the inlet flue gas SO_2 loading. The pH of the feed liquor averaged 8.1 during the testing period and ranged on a daily average basis from 7.8 to 8.8. Over the 30-day data collection period, the SO_2 removal efficiency ranged from 95.4 to 97.7 percent and averaged 96.3 percent. The sodium wet scrubbing FGD system operated at a reliability level of 100 percent during the test period.

The SO_2 removal efficiency was insensitive to changes in steam generating unit and FGD system load over the range observed during the test. Sodium wet scrubbing systems, however, operate with a scrubbing liquor sodium concentration that is greatly in excess of the theoretical amount required for SO_2 absorption. As a result, SO_2 removal performance is not mass transfer limited, but is determined by the equilibrium conditions of the scrubbing liquor. These conditions are governed primarily by the concentration of active sodium species. Consequently, increasing the SO_2 loading on the system, either by increasing the flue gas flow rate or SO_2 concentrations, would not seriously deplete excess active sodium species nor affect feed liquor pH in the short run. Thus, SO_2 removal performance will be relatively independent of load and inlet SO_2 concentration if vigorous gas-liquid contact is maintained in the absorber and the sodium-to-sulfur and liquid-to-gas ratios are maintained at a constant level.

This is verified by statistical analysis of the SO_2 performance data from the 30-day test showing that SO_2 removal efficiency was independent of SO_2 inlet concentration. It follows, therefore, that variations in steam generating unit load would similarly not affect SO_2 removal.

This test shows that 96.3 percent SO_2 removal on high sulfur coal can be reliably and consistently achieved on an industrial steam generating unit operated at normal, but less than maximum, load. A sodium wet scrubbing system could also operate at this level of performance under full load conditions by adjusting the reagent addition rate and scrubbing liquor feed rate to maintain constant sodium-to-sulfur and liquid-to-gas ratios.

These long-term data for sodium wet scrubbing systems were analyzed to determine their variability (i.e., RSD and AC) using an AR(1) time series statistical model as discussed earlier. The 24-hour RSD and AC values of the data were found to be 34 percent and 0.13, respectively, based on controlled SO_2 emissions. Using a 30-day rolling average to determine performance (i.e., percent reduction in emissions), the AR(1) model was used to project the maximum expected variation in performance, assuming this maximum variation would only be exceeded once in ten years. This once in ten years maximum expected variation in performance on a 30-day rolling average basis was found to be less than 1 percentage point.

Thus, SO_2 removal efficiency can be expected to vary by less than 1 percentage point above and below the mean SO_2 removal efficiency using a data averaging period of 30 days. Consequently, to ensure that SO_2 removal efficiency for a given sodium wet scrubbing system is consistently above a minimum performance level, the system should be operated at a long-term average performance level 1 percentage point above the minimum performance level. If the system is operated in this manner, SO_2 removal performance would be expected to fall below the minimum level only once in a ten-year period. It follows, therefore, that a sodium wet scrubbing system should be operated at a long-term average performance level of 91 percent or above to ensure that the SO_2 emissions reduction efficiency for the system is consistently at or above 90 percent.

The sodium wet scrubbing system average performance during the 30-day test was 96.3 percent, which is well above the long-term average required to meet consistently a once in ten year 30-day rolling average minimum performance level of a 90 percent reduction in SO_2 emissions. Although this performance level was achieved at an FGD system load of only 22 to 52 percent of design capacity, this same level of performance can be achieved by a new sodium wet scrubbing system at full load conditions if rigorous gas-liquid contact is maintained in the absorber and the sodium-to-sulfur and liquid-to-gas ratios are maintained at the same level to provide an adequate supply of active sodium species.

In addition to long-term performance data from coal-fired steam generating units, short-term performance data have also been gathered for sodium wet scrubbing systems applied to oil-fired industrial-commercial-institutional steam generating units. Short-term performance data are available from 12 sites where data were collected by Reference Method 8, typically over a 3-hour period. In each case, a sodium wet scrubbing system serviced an oil-fired steam generating unit ranging in size from 15 MW (50 million Btu/hour) to 63 MW (210 million Btu/hour) heat input capacity. The sulfur contents of the oils burned ranged from about 260 to 650 ng SO_2/J (0.6 to 1.5 lb SO_2/million Btu). Steam generating unit load information was not recorded.

A number of different absorber designs were represented by these tests, including a tray absorber, venturi scrubber, spray baffle, and liquid jet eductor. Sodium-to-sulfur ratios and pH levels were not recorded. The SO_2 removal efficiencies of the 12 sodium wet scrubbing systems ranged from 90.0 to 99.4 percent.

In addition to these data, other data have also been reported for sodium wet scrubbing systems applied to oil-fired industrial steam generating units. At one site, a single sodium wet scrubbing unit reduced SO_2 emissions from the combined flue gases of 5 package steam generating units, each rated at 17 MW (57 million Btu/hour) heat input capacity. The steam generating units burned crude oil with a sulfur content that ranged from 960 to 1,810 ng SO_2/J (2.22 to 4.22 lb SO_2/million Btu). Two of the units were idle during the performance period, two operated at 50 percent average load, and one operated at 95 percent average load. The combined average load on the FGD system was approximately 40 percent. The SO_2 absorber in this system consisted of a venturi eductor followed by a spray tower. The scrubbing liquor pH was maintained at 7.0. The sodium-to-sulfur ratio was not reported. The sodium wet scrubbing system performed at 95 percent SO_2 removal on average. Over an approximate 4-year period, this system operated at a reliability level near 98 percent.

At a second site, a total of 15 sodium wet scrubbers serviced a total of 19 package oil-fired steam generating units. The steam generating units ranged in size from 7 to 15 MW (25 to 50 million Btu/hour) heat input capacity. However, since in some cases multiple steam generating units were ducted to a single sodium wet scrubbing system, the size of the FGD systems ranged from 7 to 73 MW (25 to 250 million Btu/hour) equivalent heat input capacity. The steam generating units burned crude oil with a sulfur content which ranged from 720 to 830 ng SO_2/J (1.67 to 1.94 lb SO_2/million Btu). All the steam generating units operated at an average load near 85 percent of capacity. The SO_2 absorbers in these systems included tray absorbers, horizontal spray towers, and venturi scrubbers. The scrubber liquor pH was maintained near 7.0 in all cases. Sodium-to-sulfur ratios were not reported. The sodium wet scrubbing systems all operated at approximately 95 percent SO_2 removal on average. All systems operated at reliability levels in excess of 99 percent over time periods ranging from 6 to 12 months.

Based on these analyses of system performance and system variability, sodium wet scrubbing FGD technology is capable of reducing SO_2 emissions from coal-fired and oil-fired industrial-commercial-institutional steam generating units by 90 percent using a 30-day rolling average to calculate emission reductions.

5.4 PARTICULATE MATTER EMISSIONS FROM OIL COMBUSTION

Currently, the performance of particulate matter control techniques is measured with Reference Method 5. However, Reference Method 5 has been found to be subject to interference with sulfur oxides, which effectively increases measured particulate matter emissions above true values. As a result, a new reference method is under development - Reference Method 5b - that greatly reduces the problem of sulfur oxide interference. This new reference method was proposed on May 29, 1985 (50 FR 21863).

Reference Method 5b consistently results in equivalent or lower particulate matter emission measurements, with the most significant reduction being observed when measuring particulate matter emissions from the combustion of high sulfur fuels. A comparative analysis shows a 35 to 50 percent reduction in measured particulate matter emissions when Reference Method 5b is used in place of Reference Method 5 to measure the performance of electrostatic precipitation in reducing particulate matter emissions from combustion of high sulfur fuel oils.

Most of the emission performance data discussed below, however, was collected prior to the development of Reference Method 5b. Consequently, the performance of wet scrubbers and electrostatic precipitators (and to some extent, the performance of low sulfur oil) for the control of particulate matter emissions from oil-fired steam generating units may be somewhat greater than that discussed below based on the use of Reference Method 5.

The three emission control technologies considered demonstrated for the purpose of developing standards of performance limiting particulate matter emissions from oil-fired industrial-commercial-institutional steam generating units are the use of low sulfur oil and the use of "add-on" control techniques, such as electrostatic precipitators or wet scrubbers.

5.4.1 Low Sulfur Oil

As discussed earlier, fuel oils are generally classified by sulfur content (see Table 4-1). This classification scheme based on sulfur content has its origins in the classifications used by the U.S. Department of Energy to report refinery production data and in studies for fuel oil use patterns.

To determine the performance of low sulfur oil in reducing particulate matter emissions, data were collected using Reference Method 5 from three steam generating units burning a fuel oil having a fuel sulfur content of 129 ng SO_2/J (0.3 lb SO_2/million Btu) or less. The heat input capacities of these three units were 320, 355, and 600 MW (1,096, 1,215 and 2,055 million

Btu/hour). Each of the three steam generating units exhibited particulate matter emission rates of 9 ng/J (0.02 lb/million Btu) heat input.

A review of the data from over 100 steam generating units that were used to establish the relationship between fuel oil sulfur content and emissions of particulate matter from oil combustion presented in the manual, "Compilation of Air Pollutant Emission Factors" (AP-42), indicates that fuel oils having a sulfur content of 129 ng SO_2/J (0.3 lb SO_2/million Btu) or less are capable of reducing emissions of particulate matter to levels of 17 ng/J (0.04 lb/million Btu) heat input or less.

As a result, the use of fuel oils having sulfur contents less than or equal to 129 ng SO_2/J (0.3 lb SO_2/million Btu) will reduce particulate matter emissions from industrial-commercial-institutional steam generating units to 17 ng/J (0.04 lb/million Btu) heat input or less.

Emission test data using Reference Method 5 were collected for fifteen steam generating units with heat input capacities ranging from 41 to 400 MW (140 to 1,360 million Btu/hour). When combusting fuel oils with a sulfur content of 129 to 344 ng SO_2/J (0.3 to 0.8 lb SO_2/million Btu), the particulate matter emissions from thirteen of the steam generating units ranged from 9 to 43 ng/J (0.02 to 0.10 lb/million Btu) heat input. Particulate matter emissions from the remaining two steam generating units were 65 and 82 ng/J (0.15 and 0.19 lb/million Btu) heat input. Contacts with the personnel at these two units revealed that the measured particulate matter emissions were uncharacteristically high and were the result of injection nozzle problems that led to poor combustion conditions. This was supported by the existence of two other steam generating units burning the same residual fuel oil and exhibiting particulate matter emissions of 17 and 30 ng/J (0.04 and 0.07 lb/million Btu) heat input.

Review of the data from over 100 steam generating units that were used to establish the relationships between fuel oil sulfur content and emissions of particulate matter in the manual, "Compilation of Air Pollutant Emission Factors" (AP-42), indicates that fuel oils having a sulfur content between 129 and 344 ng SO_2/J (0.3 and 0.8 lb SO_2/million Btu) are capable of reducing emissions of particulate matter to levels of approximately 30 ng/J (0.07 lb/million Btu) heat input.

The use of low sulfur fuel oils having sulfur contents less than or equal to 344 ng SO_2/J (0.8 lb SO_2/million Btu), therefore, will reduce particulate matter emissions from industrial-commercial-institutional steam generating units to 43 ng/J (0.10 lb/million Btu) heat input or less.

Emission test data using Reference Method 5 were collected from twenty-three steam generating units ranging in heat input capacities from 28 to 400 MW (94 to 1,360 million Btu/hour). When combusting fuel oils having sulfur contents between 344 and 645 ng SO_2/J (0.8 and 1.5 lb SO_2/million Btu), the particulate matter emissions from twenty-two of the steam generating units ranged from 17 to 60 ng/J (0.04 to 0.14 lb/million Btu) heat input. The particulate matter emissions from one of the twenty-three units were 73 ng/J (0.17 lb/million Btu) heat input. Close examination of the other steam generating units at this site, however, indicated that average particulate matter emission rates of 52 ng/J (0.12 lb/million Btu) heat input were achieved while combusting the same type of fuel oil. These observations indicate that the steam generating unit emitting 73 ng/J (0.17 lb/million Btu) heat input was experiencing problems with poor combustion, and that proper combustion conditions would reduce the particulate matter emissions to 52 ng/J (0.12 lb/million Btu) heat input.

Review of the data from over 100 steam generating units that were used to develop the relationship between fuel oil sulfur content and emissions of particulate matter presented in the manual, "Compilation of Air Pollutant Emission Factors" (AP-42), indicates that fuel oils having sulfur contents less than 645 ng SO_2/J (1.5 lb SO_2/million Btu) are capable of reducing emissions of particulate matter to levels of approximately 52 ng/J (0.12 lb/million Btu) heat input.

As a result, the use of an intermediate sulfur fuel oil having a sulfur content of less than or equal to 645 ng SO_2/J (1.5 lb SO_2/million Btu) will reduce particulate matter emissions from industrial-commercial-institutional steam generating units to 60 ng/J (0.14 lb/million Btu) heat input or less.

5.4.2 Add-On Control Techniques

To determine the performance of electrostatic precipitators in reducing particulate matter emissions from oil combustion, emission data were collected from eight steam generating units equipped with electrostatic precipitators using Reference Method 5. Two of these steam generating units had heat input capacities of 28 MW (94 million Btu/hour) and burned a fuel oil with a sulfur content of 301 ng SO_2/J (0.7 lb SO_2/million Btu). The particulate matter emission rates as measured by Reference Method 5 averaged 24 and 30 ng/J (0.055 and 0.07 lb/million Btu) heat input.

Three steam generating units were tested which had individual heat input capacities of 1,611 MW (5,500 million Btu/hour) and burned a fuel oil with a sulfur content of 946 ng SO_2/J (2.2 lb SO_2/million Btu). The particulate matter emission rates as measured by Reference Method 5b averaged 18, 19, and 21 ng/J (0.041, 0.045, and 0.049 lb/million Btu) heat input for the three units.

Finally, three steam generating units with individual heat input capacities of 322 MW (1,100 million Btu/hour) were tested with Reference Method 5 while burning a fuel oil with a sulfur content of 796 ng SO_2/J (1.85 lb SO_2/million Btu). The particulate matter emissions from these three units averaged 25, 29, and 30 ng/J (0.057, 0.067, and 0.070 lb/million Btu) heat input.

Electrostatic precipitators, therefore, will reduce particulate matter emissions from oil-fired industrial-commercial-institutional steam generating units to 30 ng/J (0.07 lb/million Btu) heat input or less.

To determine the performance of wet scrubbers in reducing particulate matter emissions from oil combustion, emission data were collected from seven steam generating units equipped with wet scrubbers using Reference Method 5. All seven of these wet scrubbers were designed for control of both particulate matter emissions and sulfur oxide emissions. Two steam generating units with a heat input capacity of 17 MW (57 million Btu/hour) were equipped with steam venturi eductors followed by spray tower wet scrubbers. The steam generating units burned fuel oils with fuel sulfur contents of 473 and 1,204 ng SO_2/J (1.1 and 2.8 lb SO_2/million Btu), and achieved particulate matter emission levels of 22 and 43 ng/J (0.05 and 0.1 lb/million Btu) heat input, respectively.

Two steam generating units, with a heat input capacity of 15 MW (50 million Btu/hour), equipped with venturi scrubbers that operated at a liquid-to-gas ratio of 21,400 ℓ/m^3 (160 gallons/1,000 ft^3) were tested. The steam generating units burned fuel oils with fuel sulfur contents of 560 and 730 ng SO_2/J (1.3 and 1.7 lb SO_2/million Btu) and achieved particulate matter emission levels of 38 and 30 ng/J (0.09 and 0.07 lb/million Btu) heat input, respectively.

Two spray tower wet scrubbers were also tested, one serving a 7 MW (25 million Btu/hour) heat input steam generating unit and one serving five 15 MW (50 million Btu/hour) heat input steam generating units. Both scrubbers employed three trays and operated at a liquid-to-gas ratio of 2,675 ℓ/m^3 (20 gallons/1,000 ft^3). The smaller steam generating unit burned fuel oil with a sulfur content of 645 ng SO_2/J (1.5 lb SO_2/million Btu) and the five larger steam generating units burned fuel oil with a sulfur content of 473 ng SO_2/J (1.1 lb SO_2/million Btu). These two tray scrubbers achieved particulate matter emission rates of 34 and 26 ng/J (0.08 and 0.06 lb/million Btu) heat input.

Finally, a single steam generating unit with a heat input capacity of 15 MW (50 million Btu/hour) and equipped with a horizontal spray-baffle wet scrubber was tested. The liquid-to-gas ratio during the test was 6,000 ℓ/m^3 (45 gallons/1,000 ft^3). During the combustion of fuel oil with a sulfur content of 645 ng SO_2/J (1.5 lb SO_2/million Btu), the horizontal spray-baffle wet scrubber reduced emissions of particulate matter to 34 ng/J (0.08 lb/million Btu) heat input.

Each of the seven wet scrubbers discussed above achieved SO_2 emission reductions of 92 percent or greater while achieving particulate matter emission levels of 43 ng/J (0.1 lb/million Btu) heat input or less. As a result, wet scrubbing systems, including those designed for SO_2 emission control, are capable of reducing particulate matter emissions from oil-fired industrial-commercial-institutional steam generating units to 43 ng/J (0.1 lb/million Btu) heat input or less.

5.5 PARTICULATE MATTER EMISSIONS FROM COAL COMBUSTION

The use of a flue gas desulfurization system to control particulate matter emissions from coal combustion is considered a demonstrated particulate matter emission control technology. The performance of FGD systems in controlling particulate matter emissions was assessed for both coal-fired stoker steam generating units and pulverized coal-fired steam generating units.

As discussed above, Reference Method 5 has been found to be subject to interference from sulfur oxides. Thus, a new reference method that minimizes this problem of interference - Reference Method 5b - is currently under development. Measurements obtained through the use of Reference Method 5b can be as much as 50 percent lower than measurements obtained through the use of Reference Method 5.

To assess the performance of wet scrubber FGD systems in reducing particulate matter emissions, data were gathered from three industrial coal-fired stoker steam generating units. At the time these data were gathered, the problem mentioned above of sulfur oxide interference associated with the use of Reference Method 5 was recognized. Because the problem results, in part, from the condensation of sulfuric acid mist on the particulate matter collection filter, an attempt was made to minimize condensation, and hence sulfur oxide interference, by maintaining the collection filter at a temperature above the sulfuric acid dew point. Thus, the filter was maintained at a temperature of 177°C (350°F).

Although this was found to reduce sulfur oxide interference, subsequent testing during the development of Reference Method 5b indicated that condensation in the probe can also be a significant contributor to this problem of interference. Consequently, Reference Method 5b also maintains the probe as well as the filter at elevated temperatures. Reference Method 5b is also somewhat different from Reference Method 5 in several other aspects. Thus, even though the temperature of the collection filter was maintained at an elevated temperature during these tests, the use of Reference Method 5b would yield lower particulate matter emission levels.

The three coal-fired stoker steam generating units tested ranged in size from 24 to 69 MW (80 to 236 million Btu/hour) heat input capacity, and operated at loads of from 73 to 92 percent of capacity. The coals fired during the tests had sulfur contents ranging from 1.3 to 2.6 weight percent, and ash contents ranging from 4.4 to 11.4 weight percent. With operating pressure drops in the FGD scrubbers of 7.5 to 19.3 inches of water, particulate matter emission levels were reduced to 30 to 43 ng/J (0.7 to 0.10 lb/million Btu) heat input.

Data were also gathered to assess the performance of wet scrubber FGD systems applied to pulverized coal-fired steam generating units. Two pulverized coal-fired steam generating units equipped with venturi scrubber FGD systems were tested. At the time these data were being gathered, the problem of sulfur oxide interference associated with the use of Reference Method 5 was not recognized. As a result, these data were gathered through the use of Reference Method 5. The use of Reference Method 5b, therefore, would yield lower particulate matter emission levels.

The two pulverized coal-fired steam generating units tested had heat input capacities of 29 and 40 MW (100 and 137 million Btu/hour) and were both operated at a load of 100 percent. The coals fired during the tests had sulfur contents ranging from 3.5 to 3.9 weight percent, and ash contents ranging from 12 to 15 weight percent. With operating pressure drops in the FGD scrubbers of 9 and 21 inches of water, average particulate matter emissions from each steam generating unit were reduced to less than 30 ng/J (0.07 lb/million Btu) heat input.

These data are representative of the performance of wet scrubber FGD systems on stoker and pulverized coal-fired steam generating units firing high ash coals at high steam generating unit loads. Both of these conditions contribute to relatively high uncontrolled particulate matter emission rates and thus represent the performance of wet scrubber FGD systems under relatively adverse conditions. Therefore, wet scrubbing FGD systems installed on coal-fired industrial-commercial-institutional steam generating units are capable of reducing particulate matter emissions from these units to 43 ng/J (0.10 lb/million Btu) heat input or less.

Fabric filters and ESP's, as well as other FGD systems, such as lime spray drying systems, which incorporate these particulate matter control technologies in their design and operation, are also demonstrated technologies for controlling particulate matter emissions from coal-fired steam generating units. The performance of fabric filters and ESP's was discussed in the new source performance standards proposed on June 19, 1984 (49 FR 25102). Both fabric filters and ESP's, as well as those FGD systems that incorporate fabric filters and ESP's in their design and operation, are capable of reducing particulate matter emissions from coal-fired industrial-commercial-institutional steam generating units to 21 ng/J (0.05 lb/million Btu) heat input or less.

6.0 CONSIDERATION OF DEMONSTRATED EMISSION CONTROL TECHNOLOGY COSTS

The cost impacts associated with the use of the various demonstrated emission control technologies to reduce emissions of SO_2 from coal-fired, oil-fired, and mixed fuel-fired (i.e., mixtures of fossil or fossil and nonfossil fuels) industrial-commercial-institutional steam generating units and emissions of particulate matter from oil-fired industrial-commercial-institutional steam generating units were evaluated in three ways: increases in capital costs; increases in annualized costs, including both annual fixed capital charges and annual operating and maintenance costs; and the cost effectiveness of emission control, or the cost per unit quantity of pollutant removed. In each case, absolute costs of emission control were examined, as well as incremental increases in cost.

Costs were estimated using cost algorithms to project capital costs and annual operating and maintenance costs. Capital costs include the cost of the equipment and its installation, indirect expenses such as engineering fees and startup costs, and interest during construction. Annual operating and maintenance costs include labor, utilities, raw materials, and waste treatment and disposal. These cost algorithms are based on actual plant cost data and vendor quotes.

Capital costs of flue gas desulfurization (FGD) systems reflect the current practice of owners of industrial-commercial-institutional steam generating units to design and install FGD systems capable of achieving 90 percent SO_2 removal with no flue gas bypass in order to provide maximum fuel flexibility. This conservative design practice permits the steam generating unit to fire the least expensive coal or oil available to minimize operating costs. Annual operating and maintenance costs, however, reflect operation at the minimal percent SO_2 removal necessary to comply with regulatory requirements considering the sulfur content of the actual fuel fired.

The prices and specifications for various coals, oils, and natural gas that were used in this analysis are discussed in "Consideration of National Impacts." All fuel prices were levelized at a 10 percent discount rate over a 15-year period beginning in 1987, and were adjusted to January 1983 dollars.

The financial parameters used in this analysis include an amortization period of 15 years and a real cost of capital of 10 percent in constant dollars. A real rather than a nominal cost of capital is used in order to avoid having to make adjustments for varying inflation rates. For example, an assumed inflation rate of 8 percent and a 10 percent real cost of capital is equivalent to an 18 percent nominal cost of capital. All costs are presented in January 1983 dollars.

Costs presented in this analysis also include costs of demonstrating compliance with applicable regulations through the use of continuous emission monitoring devices. Costs to maintain compliance during periods of FGD system malfunction are also included and are based on the firing of natural gas during periods of FGD malfunction.

To analyze the potential cost impacts associated with the use of various emission control technologies to reduce SO_2 emissions from new industrial-commercial-institutional steam generating units, a regulatory baseline must be selected for the analysis. The regulatory baseline reflects the general level of emission control that would be required in the absence of new source performance standards (NSPS).

Emissions of SO_2 from most steam generating units covered by the proposed standards are currently controlled under existing State implementation plans (SIP's). The level of SO_2 control required under current SIP regulations varies considerably by location. In addition, regulatory requirements associated with the prevention of significant deterioration (PSD) and new source review (NSR) programs also limit emissions of SO_2 from the steam generating units covered by the proposed standards. Furthermore, emissions of SO_2 from new steam generating units with heat input capacities greater than 73 MW (250 million Btu/hour) are currently limited to 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input under the existing NSPS (40 CFR 60 Subpart D) promulgated in 1971.

An analysis of SIP requirements limiting SO_2 emissions from both coal-fired and oil-fired industrial-commercial-institutional steam generating units indicates that the "average" SIP SO_2 emission limit is approximately 1,075 ng SO_2/J (2.5 lb SO_2/million Btu) heat input. This average SIP limit corresponds to the emissions generated during the combustion of a medium sulfur coal or the combustion of a high sulfur oil. The use of this average SIP emission limit as the regulatory baseline for coal- and oil-fired steam generating units tends to overstate the cost impacts associated with the use of various emission control technologies. Approximately 40 percent of SIP's for steam generating units with heat input capacities of 73 MW (250 million Btu/hour) or less, for example, are more stringent than this average SIP emission limit.

Also, as mentioned earlier, regulatory requirements associated with the PSD and NSR programs are often more stringent than SIP's. A review of recent PSD and NSR permits for coal-fired industrial-commercial-institutional steam generating units, for example, indicates that approximately 50 percent of all PSD/NSR permits for units with heat input capacities of 73 MW (250 million Btu/hour) or less, and all permits for units with heat input capacities greater than 73 MW (250 million Btu/hour), limit SO_2 emissions to 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input or less.

A regulatory baseline reflecting the average SIP emission limit, however, better illustrates the comparative costs of different SO_2 emission control technologies than a regulatory baseline based on the more stringent PSD/NSR programs. For purposes of this analysis, therefore, average SIP emission limits of 1,075 ng SO_2/J (2.5 lb SO_2/million Btu) and 1,290 ng SO_2/J (3.0 lb SO_2/million Btu) heat input were selected as the regulatory baselines for coal- and oil-fired steam generating units, respectively. [As discussed in "Consideration of National Impacts," the projected coal prices used in this analysis include a coal type containing 1,075 ng SO_2/J (2.5 lb SO_2/million Btu) heat input. The projected oil prices, however, include oil types containing 688 ng SO_2/J (1.6 lb SO_2/million Btu) and 1,290 ng SO_2/J (3.0 lb SO_2/million Btu) heat input. Thus, the regulatory baseline for oil was assumed to be 1,290 ng SO_2/J (3.0 lb SO_2/million Btu) heat input, rather than 688 ng SO_2/J (1.6 lb SO_2/million Btu), to reflect combustion of high sulfur oil rather than medium sulfur oil.]

In addition to being based on the use of average SIP emission limits to represent the regulatory baseline, the cost impacts discussed below represent the maximum impacts associated with an NSPS on a specific industrial-commercial-institutional steam generating unit. In many cases, the actual cost impacts associated with an NSPS will be lower because steam generating unit operators have the option of firing relatively sulfur-free fuels to avoid many of the costs associated with compliance with an NSPS. For example, rather than install an FGD system to reduce SO_2 emissions from combustion of coal, an operator may elect to avoid the costs of such a system by firing natural gas.

6.1 COSTS OF SULFUR DIOXIDE EMISSION CONTROL FOR COAL-FIRED STEAM GENERATING UNITS

As discussed in "Selection of Demonstrated Emission Control Technologies," there are two basic approaches that can be used to reduce SO_2 emissions from coal-fired steam generating units: the combustion of low sulfur coals, or the use of FGD systems. The FGD systems that are considered demonstrated for the purposes of developing an NSPS for coal-fired industrial-commercial-institutional steam generating units are sodium, dual alkali, lime, limestone, and lime spray drying. Table 6-1 presents the costs of SO_2 control for these technologies achieving 90 percent SO_2 removal on high and low sulfur coals on a 44 MW (150 million Btu/hour) heat input capacity steam generating unit in EPA Region V. As shown, the annualized costs of SO_2 control for the various FGD technologies are generally within 30 percent of each other. These differences in costs are minimal in terms of the total annualized cost of a steam generating unit with an FGD system. The variation in costs among the different FGD technologies, in terms of the total annualized costs for the steam generating unit with an FGD system, is generally less than 4 percent.

TABLE 6-1. COSTS OF DEMONSTRATED FLUE GAS DESULFURIZATION SYSTEMS[a]

		Sodium Scrubbing FGD		Dual Alkali FGD		Dry Lime FGD	
	Uncontrolled[b]	SO_2[c]	Total	SO_2[c]	Total	SO_2[c]	Total
Capital Cost ($1,000)							
High Sulfur Coal[d]	14,020	920	14,940	2,410	16,430	1,550	15,570
Low Sulfur Coal[e]	14,070	830	14,900	2,350	16,420	1,480	15,550
Annualized Cost ($1,000/year)							
High Sulfur Coal[d]	5,700	920	6,620	1,170	6,870	1,090	6,790
Low Sulfur Coal[e]	6,340	490	6,830	910	7,250	740	7,080

[a]Based on 90 percent SO_2 removal on a 44 MW (150 million Btu/hour) steam generating unit in EPA Region V.

[b]Costs include NO_x control and particulate matter control.

[c]Cost of SO_2 control is incremental cost over uncontrolled steam generating unit.

[d]Sulfur content = 2380 ng SO_2/J (5.54 lb SO_2/million Btu); fuel price = $2.37/GJ ($2.50/million Btu).

[e]Sulfur content = 409 ng SO_2/J (0.95 lb SO_2/million Btu); fuel price = $3.14/GJ ($3.32/million Btu).

In any particular situation, the lowest cost FGD technology will vary depending on the size and capacity utilization factor of the steam generating unit, sulfur content of the coal, and percent removal achieved by the FGD system. For small steam generating units operating at low capacity utilization factors and firing low sulfur coal, sodium scrubbing is generally significantly less costly than the other FGD technologies. However, as steam generating unit size and capacity utilization factor increase, and as the sulfur content of the coal and SO_2 removal requirements increase, the costs of other FGD technologies become more favorable. At the larger steam generating unit sizes and capacity utilization factors, the costs of all the FGD technologies examined are generally comparable.

Sodium scrubbing is currently the most widely used FGD technology for industrial-commercial-institutional steam generating units. In addition, as outlined above, its costs can be considered representative of FGD technology costs in general. Consequently, sodium scrubbing was used to represent the costs of FGD systems in this analysis.

A separate analysis of the relative competitiveness of fluidized bed combustion (FBC) versus the use of conventional coal-fired steam generating units was performed to examine the potential impact that new source performance standards might have on the use of FBC technology. The results of this analysis indicate that FBC systems, operated to control SO_2 emissions, are slightly more expensive than conventional coal-fired steam generating units that fire a low sulfur fuel to achieve the same level of SO_2 control.

On the other hand, the results of the analysis also indicate that the costs associated with an FBC system and a conventional coal-fired steam generating unit using an FGD system to reduce SO_2 emissions are currently about the same. Under these conditions, FBC systems are competitive with conventional steam generating units.

This is essentially no different than the situation as it presently exists regarding the relative competitiveness of FBC systems and conventional coal-fired steam generating units. Even in the absence of considerations regarding control of SO_2 emissions, FBC systems are usually slightly more expensive than conventional steam generating units. As a result, the application of FBC systems has generally been limited to those situations where concerns relating to fuel flexibility, or the need to combust low-grade fuels, are paramount. As a result, the proposed new source performance standards will neither preclude nor hinder the use of FBC technology.

The costs and cost impacts associated with a given alternative control level for a specific coal-fired steam generating unit vary depending on its geographic location. This variation is due primarily to regional differences in the prices of coal. This analysis focuses on the costs associated with the various alternative control levels for coal-fired steam generating units located in EPA Region V and EPA Region VIII. Region V includes the states of Minnesota, Wisconsin, Illinois, Indiana, Michigan, and Ohio. The coal types available in Region V include high and low sulfur eastern bituminous coals, and low sulfur western subbituminous coals. The prices and types of coals available in Region V are representative of those in the eastern and midwestern states. Region VIII includes the states of Colorado, Wyoming, Utah, Montana, North Dakota, and South Dakota. The coal types available in Region VIII include low and medium sulfur bituminous and subbituminous coals. The prices and types of coal available in Region VIII are typical of those in other western states. In addition, Region VIII has the lowest coal prices in the country and, therefore, the cost impacts of alternative control levels requiring a specific percent reduction in SO_2 emissions through the use of FGD are the highest in Region VIII.

Finally, the costs presented in this analysis for each of the alternative control levels discussed below are based on the use of the "least cost" approach for complying with that alternative. For example, to comply with an alternative of 50 percent SO_2 emission reduction and an emission ceiling of 387 ng/J (0.9 lb/million Btu) heat input, it may be less costly to operate an FGD system at 90 percent SO_2 removal on a high sulfur coal than it is to operate an FGD system at 50 percent removal on a low sulfur coal. In other words, the savings that result from firing less expensive high sulfur coal rather than more expensive low sulfur coal may be more than enough to compensate for the increased cost of operating an FGD system at 90 percent emission reduction rather than at 50 percent emission reduction.

A number of alternative control levels could be examined to assess the potential cost impacts associated with new source performance standards based on the use of low sulfur coal and new source performance standards requiring a percent reduction in SO_2 emissions. As discussed in "Performance of Demonstrated Emission Control Technologies," SO_2 emissions could be reduced to 731 ng SO_2/J (1.7 lb SO_2/million Btu) heat input and 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input through the use of low sulfur coals. Therefore, each of these alternatives merits consideration.

There are two viewpoints from which the analysis of potential cost impacts associated with alternative SO_2 percent reduction requirements could be approached. One viewpoint is that, because FGD systems can be operated over a wide range of SO_2 removal efficiencies, a range of SO_2 percent reduction requirements merit consideration. Achieving a percent reduction in SO_2 emissions of much less than 50 percent, however, would not reduce emissions to less than 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input on most coal types. Consequently, the lowest percent reduction requirement that merits serious consideration under this viewpoint is 50 percent. As discussed in "Performance of Demonstrated Emission Control Technologies," FGD technologies are capable of reducing SO_2 emissions by 90 percent. This, therefore, is the highest percent reduction requirement that merits consideration. To examine an intermediate percent reduction requirement between 50 and 90 percent, a requirement of 70 percent reduction can be considered.

Combining these three alternative percent reduction requirements with the maximum expected SO_2 emission rates associated with combustion of the various coals discussed earlier in "Performance of Demonstrated Emission Control Technologies" results in the various SO_2 emission ceilings summarized in Table 6-2. As shown, for a minimum percent reduction requirement of 50 percent, there are only two alternatives with SO_2 emission

TABLE 6-2. SO_2 EMISSION CEILINGS ASSOCIATED WITH VARIOUS PERCENT REDUCTION REQUIREMENTS

Coal Type	Maximum Expected SO_2 Emission Rate[a]	SO_2 Emission Ceiling[a]		
		50 Percent Reduction	70 Percent Reduction	90 Percent Reduction
Low Sulfur	516 (1.2)	258 (0.6)	172 (0.4)	65 (0.15)
Low Sulfur	731 (1.7)	387 (0.9)	215 (0.5)	86 (0.2)
Medium Sulfur	1,118 (2.6)	559 (1.3)	344 (0.8)	129 (0.3)
Medium Sulfur	1,592 (3.7)	817 (1.9)	473 (1.1)	172 (0.4)
High Sulfur	2,237 (5.2)	1,118 (2.6)	688 (1.6)	215 (0.5)
High Sulfur	2,710 (6.3)	1,376 (3.2)	817 (1.9)	258 (0.6)

[a]Emission rates and emission ceilings in ng SO_2/J (lb SO_2/million Btu) heat input.

ceilings below 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input - 387 ng SO_2/J (0.9 lb SO_2/million Btu) and 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input. As mentioned above, the use of low sulfur coal could reduce SO_2 emissions to 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input. Consequently, these two alternatives are the only two associated with a percent reduction requirement of 50 percent that would be more effective in reducing SO_2 emissions than the use of low sulfur coal, and they are the only two that merit consideration.

Assuming that a 70 percent reduction requirement should be more effective in reducing SO_2 emissions than a 50 percent reduction requirement, there are also only two alternatives associated with a 70 percent reduction requirement that merit consideration. As shown in Table 6-2, these two alternatives have emission ceilings of 215 ng SO_2/J (0.5 lb SO_2/million Btu) heat input and 172 ng SO_2/J (0.4 lb SO_2/million Btu) heat input.

Finally, assuming that a 90 percent reduction requirement should be more effective in reducing SO_2 emissions than a 70 percent reduction requirement, there are only three alternatives associated with a 90 percent reduction requirement that merit consideration. As shown in Table 6-2, these three alternatives have emission ceilings of 129 ng SO_2/J (0.3 lb SO_2/million Btu), 86 ng SO_2/J (0.2 lb SO_2/million Btu), and 65 ng SO_2/J (0.15 lb SO_2/million Btu) heat input.

This viewpoint, that a range of percent reduction requirements should be considered, therefore, leads to seven alternative percent reduction requirements: two alternatives associated with a 50 percent reduction requirement, two alternatives associated with a 70 percent reduction requirement, and three alternatives associated with a 90 percent reduction requirement. Rather than examine all seven percent reduction requirements, however, the following four alternatives were selected for analysis:

1. 50 percent reduction - 387 ng SO_2/J (0.9 lb SO_2/million Btu)
2. 50 percent reduction - 258 ng SO_2/J (0.6 lb SO_2/million Btu)
3. 70 percent reduction - 172 ng SO_2/J (0.4 lb SO_2/million Btu)
4. 90 percent reduction - 86 ng SO_2/J (0.2 lb SO_2/million Btu)

These four alternative percent reduction requirements are representative of the range of alternative percent reduction requirements discussed above.

Combining these four alternative percent reduction requirements with the two alternatives mentioned above based on the use of low sulfur coal, in addition to the regulatory baseline, results in seven alternative control levels for analysis, as summarized in Table 6-3.

As mentioned, however, there is another viewpoint from which the analysis of potential cost impacts associated with alternative percent reduction requirements could be approached. This viewpoint is that since FGD technologies are capable of achieving a 90 percent reduction in emissions, and FGD systems for industrial-commercial-institutional steam generating units are currently designed to achieve this level of performance, 90 percent reduction is the only percent reduction requirement that merits consideration.

As shown in Table 6-2, combining a 90 percent reduction requirement with the maximum expected SO_2 emission rates associated with combustion of the various coals discussed in "Performance of Demonstrated Emission Control Technologies" results in six alternatives, all with SO_2 emission ceilings of less than 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input. Rather than examine all six of these alternatives, however, the following three were selected for analysis:

1. 90 percent reduction - 258 ng SO_2/J (0.6 lb SO_2/million Btu)
2. 90 percent reduction - 172 ng SO_2/J (0.4 lb SO_2/million Btu)
3. 90 percent reduction - 86 ng SO_2/J (0.2 lb SO_2/million Btu)

These three percent reduction requirements are representative of the range of alternative percent reduction requirements discussed.

Combining these three alternative percent reduction requirements with the two alternatives based on the use of low sulfur coal, in addition to the regulatory baseline, results in six alternate control levels for analysis under this viewpoint, as shown in Table 6-4.

TABLE 6-3. ALTERNATIVE CONTROL LEVELS FOR COAL-FIRED INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

Range of Percent Reduction Requirements

Percent Reduction/ Emission Ceiling, ng SO_2/J (lb SO_2/million Btu)	Control Method
None / 1075 (2.5)[a]	Medium Sulfur Coal
None / 731 (1.7)	Low Sulfur Coal
None / 516 (1.2)	Low Sulfur Coal
50% / 387 (0.9)	FGD with 50% Removal
50% / 258 (0.6)	FGD with 50% Removal
70% / 172 (0.4)	FGD with 70% Removal
90% / 86 (0.2)	FGD with 90% Removal

[a]Represents regulatory baseline.

TABLE 6-4. ALTERNATIVE CONTROL LEVELS FOR COAL-FIRED INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

90 Percent Reduction Requirement

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	Control Method
None / 1075 (2.5)[a]	Medium Sulfur Coal
None / 731 (1.7)	Low Sulfur Coal
None / 516 (1.2)	Low Sulfur Coal
90% / 258 (0.6)	FGD with 90% Removal
90% / 172 (0.4)	FGD with 90% Removal
90% / 86 (0.2)	FGD with 90% Removal

[a]Represents regulatory baseline.

Each viewpoint, therefore, results in a somewhat different set of alternative control levels for analysis. This analysis examined both sets of alternative control levels. For convenience, the alternative control levels resulting from the first viewpoint are referred to as "range of percent reduction requirements" and the alternative control levels resulting from the second viewpoint are referred to as "90 percent reduction requirement."

Before presenting and discussing the results of this analysis, however, one additional point should be mentioned. A percent reduction requirement with a low SO_2 emission ceiling may preclude combustion of certain coals. Although an SO_2 emission ceiling of 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input does not preclude combustion of any coal in this analysis, coals containing more than 2,580 ng SO_2/J (6.0 lb SO_2/million Btu) heat input could not be burned and SO_2 emissions reduced to 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input, assuming that 90 percent SO_2 emission reduction is the maximum percentage reduction in SO_2 emissions that can be achieved with any FGD system.

Similarly, the SO_2 emission ceilings of 172 ng SO_2/J (0.4 lb SO_2/million Btu) and 86 ng SO_2/J (0.2 lb SO_2/million Btu) heat input associated with the 90 percent reduction requirement discussed above would generally preclude combustion of coals containing more than 1,720 ng SO_2/J (4.0 lb SO_2/million Btu) and 860 ng SO_2/J (2.0 lb SO_2/million Btu) heat input, respectively. Thus, an SO_2 emission ceiling of 172 ng SO_2/J (0.4 lb SO_2/million Btu) heat input would generally limit steam generating units to combustion of low or medium sulfur coals, even with the use of FGD systems to reduce SO_2 emissions. Similarly, an SO_2 emission ceiling of 86 ng SO_2/J (0.2 lb SO_2/million Btu) heat input would generally limit steam generating units to combustion of low sulfur coals.

6.1.1 <u>Range of Percent Reduction Requirements</u>

The cost impacts associated with each alternative control level were examined for a typical industrial-commercial-institutional coal-fired steam generating unit. This steam generating unit has a heat input capacity of 44 MW (150 million Btu/hour) and an annual capacity utilization factor of 0.60. The annual capacity utilization factor of a steam generating unit is defined as the actual annual heat input to the unit divided by the maximum annual heat input to the unit if it were operated at design capacity for 24 hours per day, 365 days per year (8,760 hours per year). Table 6-5 summarizes the results for Region V and Table 6-6 summarizes the results for Region VIII.

Tables 6-5 and 6-6 show that the increase in capital costs associated with each of the alternative control levels based on the use of low sulfur coal are essentially the same as those for a steam generating unit at the regulatory baseline. An increase in the capital costs ranging from $0.7 to $0.8 million, however, is associated with the various alternative control levels that require a percent reduction in SO_2 emissions. This represents an increase of about 5 percent in the capital costs for a typical 44 MW (150 million Btu/hour) heat input capacity coal-fired industrial-commercial-institutional steam generating unit.

The additional annualized costs for a typical 44 MW (150 million Btu/hour) heat input capacity coal-fired steam generating unit associated with the various alternative control levels based on the use of low sulfur coal would range from $70,000 to $180,000 per year, representing an increase of less than 3 percent over the regulatory baseline. The additional annualized costs associated with the various alternative control levels that require a percent reduction in emissions would range from about $440,000 to $610,000 per year, depending on the percent removal required and location (i.e., Region V or Region VIII). This represents an increase in steam generating unit annualized costs of 7 to 12 percent over the annualized costs at the regulatory baseline.

The average cost effectiveness of emission control is calculated as the difference in costs between a particular control level and the regulatory baseline, divided by the difference in emission reductions between that control level and the regulatory baseline. Tables 6-5 and 6-6 show that the average cost effectiveness of SO_2 emission control associated with the various alternative control levels based on the use of low sulfur coal

TABLE 6-5. COST IMPACTS OF A 44 MW (150 MILLION BTU/HOUR) COAL-FIRED STEAM GENERATING UNIT IN EPA REGION V

Range of Percent Reduction Requirements

Alternative Control Level		"Least Cost" Approach						
Percent Reduction	SO_2 Emission Ceiling ng/J (lb/million Btu)	Percent Removal	Coal Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Annual Emissions Mg/yr (ton/yr)	Capital Cost $million	Annualized Cost $1,000/yr	Average Cost Effectiveness $/Mg($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
None	1,075 (2.5)	0	894 (2.08)	750 (830)	14.1	6,160	-	-
None	731 (1.7)	0	589 (1.37)	520 (570)	14.1	6,230	300 (270)	300 (270)
None	516 (1.2)	0	404 (0.94)	340 (370)	14.1	6,340	430 (390)	610 (550)
50	387 (0.9)	83	1,793 (4.17)	240 (260)	14.9	6,600	850 (770)	2,600 (2,360)
50	258 (0.6)	89	1,793 (4.17)	150 (170)	14.9	6,630	780 (710)	360 (330)
70	172 (0.4)	92	1,793 (4.17)	110 (120)	14.9	6,640	750 (680)	220 (200)
90	86 (0.2)	90	589 (1.37)	50 (60)	14.9	6,770	870 (790)	2,390 (2,170)

TABLE 6-6. COST IMPACTS OF A 44 MW (150 MILLION BTU/HOUR) COAL-FIRED STEAM GENERATING UNIT IN EPA REGION VIII

Range of Percent Reduction Requirements

Alternative Control Level		"Least Cost" Approach						
Percent Reduction	SO_2 Emission Ceiling ng/J (lb/million Btu)	Percent Removal	Coal Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Annual Emissions Mg/yr (tons/yr)	Capital Cost $million	Annualized Cost $1,000/yr	Average Cost Effectiveness $/Mg($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
None	1,075 (2.5)	0	894 (2.08)	750 (830)	15.2	4,950	-	-
None	731 (1.7)	0	589 (1.37)	520 (570)	15.2	5,040	390 (350)	390 (350)
None	516 (1.2)	0	404 (0.94)	340 (370)	15.2	5,050	240 (220)	60 (50)
50	387 (0.9)	50	894 (2.08)	240 (260)	15.9	5,510	1,080 (980)	4,600 (4,180)
50	258 (0.6)	70	404 (0.94)	150 (170)	15.9	5,510	940 (850)	0 (0)
70	172 (0.4)	90	404 (0.94)	110 (120)	15.9	5,530	900 (820)	440 (400)
90	86 (0.2)	84	404 (0.94)	50 (60)	15.9	5,540	850 (770)	190 (170)

ranges from approximately \$240 to \$430/Mg (\$220 to \$390/ton) for a typical 44 MW (150 million Btu/hour) heat input capacity steam generating unit. The average cost effectiveness of alternative control levels requiring a percent reduction in SO_2 emissions ranges from about \$750 to \$1,080/Mg (\$680 to \$980/ton) of SO_2 removed.

The incremental cost effectiveness of SO_2 control was also examined. Incremental cost effectiveness is defined as the difference in cost between two alternative control levels divided by the difference in emission reductions achieved by the two alternative control levels. Tables 6-5 and 6-6 show that the incremental cost effectiveness of SO_2 emission control between alternative control levels based on the use of low sulfur coal varies from \$610/Mg (\$550/ton) in Region V to \$60/Mg (\$50/ton) in Region VIII. This difference is due to the differences in price between the two types of low sulfur coal in Region V and Region VIII. In Region V there is a significant difference in the price of these two types of low sulfur coal. In Region VIII, however, there is little difference. Thus, the incremental cost effectiveness of control is higher in Region V than in Region VIII.

For an alternative control level requiring a 50 percent reduction in SO_2 emissions and an alternative control level based on the use of low sulfur coal to meet an emission level of 516 ng SO_2/J (1.2 lb SO_2/million Btu), the incremental cost effectiveness also varies substantially between Regions V and VIII. In Region V, the incremental cost effectiveness is about \$2,600/Mg (\$2,360/ton) of SO_2 removed; in Region VIII, the incremental cost effectiveness is about \$4,600/Mg (\$4,180/ton).

This difference in incremental cost effectiveness is also explained by differences in the availability of various coal types and coal prices between the two regions. Steam generating units in Region V will fire a high sulfur coal in response to a control level requiring a 50 percent reduction in SO_2 emissions with an emission ceiling of 387 ng SO_2/J (0.9 lb SO_2/million Btu) heat input. This high sulfur coal is much lower in price than low sulfur coal in Region V. The savings from firing this less expensive coal, compared to firing the more expensive low sulfur coal, minimizes the cost impacts associated with the use of FGD to achieve a 50 percent reduction in SO_2 emissions.

Steam generating units in Region VIII will fire a medium sulfur coal to meet this same alternative control level. There is little difference in price between low and medium sulfur coals in Region VIII. Consequently, the cost impacts of requiring a 50 percent reduction in SO_2 emissions are not mitigated by lower fuel prices resulting from firing a higher sulfur coal.

The incremental cost effectiveness of increasingly more stringent alternative control levels requiring a percent reduction in SO_2 emissions is also shown in Tables 6-5 and 6-6. In each case, the incremental cost effectiveness of more stringent alternative control levels is less than \$440/Mg (\$400/ton), with one exception.

In Region V, the incremental cost effectiveness of requiring a 90 percent SO_2 emission reduction with an emission ceiling of 86 ng SO_2/J (0.2 lb SO_2/million Btu) heat input is about \$2,390/Mg (\$2,170/ton). When a 90 percent reduction is required with an emission ceiling of 86 ng SO_2/J (0.2 lb SO_2/million Btu) heat input, a steam generating unit must fire a low sulfur coal, whereas a high sulfur coal can be fired to meet the less stringent alternatives. The high price of low sulfur coal compared to high sulfur coal in Region V, therefore, increases the costs and leads to a less favorable cost effectiveness value for SO_2 emission control.

In Region VIII, however, the price differential between various coal types is small. The incremental cost effectiveness of increasingly more stringent alternative control levels is determined primarily by differences in FGD operating costs. Because FGD operating costs increase only slightly with increasing SO_2 removal efficiency, but substantial emission reductions are achieved at more stringent control levels, the incremental cost effectiveness is less than \$440/Mg (\$400/ton) in Region VIII.

The cost impacts of alternative control levels were also examined as a function of steam generating unit size. The results are summarized in Table 6-7 for Region V and Table 6-8 for Region VIII. These tables present the increases in capital costs, the increases in annualized costs, and the cost effectiveness of control for typical 29, 44, 73, and 117 MW (100, 150, 250,

TABLE 6-7. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT SIZE IN EPA REGION V

Range of Percent Reduction Requirements

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	50%/ 387(0.9)	50%/ 258(0.6)	70%/ 172(0.4)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent						
29 MW (100 million Btu/hour)	0	0	7	7	7	7
44 MW (150 million Btu/hour)	0	0	6	6	6	6
73 MW (250 million Btu/hour)	0	0	5	5	5	5
117 MW (400 million Btu/hour)	0	0	5	5	5	4
Increase in Annualized Cost Over Baseline, percent						
29 MW (100 million Btu/hour)	1	3	8	8	8	10
44 MW (150 million Btu/hour)	1	3	7	8	8	10
73 MW (250 million Btu/hour)	1	3	6	6	7	9
117 MW (400 million Btu/hour)	1	3	6	6	6	9
Average Cost Effectiveness, \$/Mg(\$/ton)						
29 MW (100 million Btu/hour)	320(290)	470(430)	1,010(920)	940(850)	880(800)	1,000(910)
44 MW (150 million Btu/hour)	300(270)	430(390)	850(770)	780(710)	750(680)	870(790)
73 MW (250 million Btu/hour)	330(300)	460(420)	720(650)	660(600)	630(570)	780(710)
117 MW (400 million Btu/hour)	340(310)	460(420)	620(560)	580(530)	550(500)	700(640)
Incremental Cost Effectiveness, \$/Mg(\$/ton)						
29 MW (100 million Btu/hour)	320(290)	670(610)	3,120(2,840)	390(350)	300(270)	2,480(2,250)
44 MW (150 million Btu/hour)	300(270)	610(550)	2,600(2,360)	360(330)	220(200)	2,390(2,170)
73 MW (250 million Btu/hour)	330(300)	640(580)	1,710(1,550)	310(280)	230(210)	2,530(2,300)
117 MW (400 million Btu/hour)	340(310)	630(570)	1,210(1,100)	340(310)	220(200)	2,480(2,250)

TABLE 6-8. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT SIZE IN EPA REGION VIII

Range of Percent Reduction Requirements

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	50%/ 387(0.9)	50%/ 258(0.6)	70%/ 172(0.4)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent						
29 MW (100 million Btu/hour)	0	0	5	5	5	5
44 MW (150 million Btu/hour)	0	0	5	5	5	5
73 MW (250 million Btu/hour)	0	0	4	4	4	4
117 MW (400 million Btu/hour)	0	0	4	4	4	4
Increase in Annualized Cost Over Baseline, percent						
29 MW (100 million Btu/hour)	2	2	11	12	12	12
44 MW (150 million Btu/hour)	2	2	11	11	12	12
73 MW (250 million Btu/hour)	2	2	10	10	10	11
117 MW (400 million Btu/hour)	2	2	10	10	11	11
Average Cost Effectiveness, $/Mg($/ton)						
29 MW (100 million Btu/hour)	390(350)	250(230)	1,220(1,110)	1,060(960)	1,000(910)	950(860)
44 MW (150 million Btu/hour)	390(350)	240(220)	1,080(980)	940(850)	900(820)	850(770)
73 MW (250 million Btu/hour)	390(350)	250(230)	940(850)	840(760)	790(720)	750(680)
117 MW (400 million Btu/hour)	390(350)	250(230)	860(780)	760(690)	730(660)	690(630)
Incremental Cost Effectiveness, $/Mg($/ton)						
29 MW (100 million Btu/hour)	390(350)	90(80)	4,970(4,520)	0(0)	300(270)	280(250)
44 MW (150 million Btu/hour)	390(350)	60(50)	4,610(4,180)	0(0)	440(400)	190(170)
73 MW (250 million Btu/hour)	390(350)	70(60)	3,640(3,310)	150(140)	230(210)	330(300)
117 MW (400 million Btu/hour)	390(350)	90(80)	3,200(2,910)	140(130)	300(270)	280(250)

and 400 million Btu/hour) heat input capacity steam generating units. As shown, the results and trends discussed above for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit generally apply to other steam generating unit sizes as well. Cost impacts of alternative control levels based on the use of low sulfur coals change very little with respect to unit size. Cost impacts of alternative control levels requiring a percent reduction in SO_2 emissions, however, decrease with increasing steam generating unit size due to the economies of scale of FGD systems.

Steam generating unit size has the greatest impact on the incremental cost effectiveness between alternative control levels requiring a percent reduction in emissions and alternative control levels based on the use of low sulfur coal. For example, in Region V the incremental cost effectiveness of the least stringent alternative control level requiring a percent reduction in emissions over the most stringent alternative control level based on the use of low sulfur coal is about $3,120/Mg ($2,840/ton) of SO_2 removed for a 29 MW (100 million Btu/hour) heat input capacity steam generating unit. The incremental cost effectiveness decreases to $1,210/Mg ($1,100/ton) of SO_2 removed for a 117 MW (400 million Btu/hour) heat input capacity steam generating unit in Region V. Similarly, in Region VIII the incremental cost effectiveness decreases from $4,970/Mg ($4,520/ton) to $3,200/Mg ($2,910/ton) as steam generating unit heat input capacity increases from 29 MW to 117 MW (100 to 400 million Btu/hour).

Finally, the cost impacts of the alternative control levels were examined as a function of steam generating unit annual capacity utilization factor. The variations in cost impacts with annual capacity utilization factor were examined for 44 MW (150 million Btu/hour) heat input capacity steam generating units in Regions V and VIII. Cost impacts were examined for annual capacity utilization factors of 0.15, 0.30, and 0.60.

Capital costs for a given steam generating unit are fixed, regardless of the annual capacity utilization factor of the unit. However, operation and maintenance costs, such as labor, fuel, utilities, raw materials, and waste disposal, decrease with decreasing annual capacity utilization factor. Therefore, at low annual capacity utilization factors capital charges represent a large percentage of the total annualized cost of control. As annual capacity utilization factor increases, however, capital charges become less important. Annual emissions, of course, are directly proportional to the annual capacity utilization factor of the steam generating unit.

Cost impacts associated with alternative control levels based on the use of low sulfur coal are essentially constant with respect to annual capacity utilization factor, since differences in fuel prices are independent of annual capacity utilization factor. However, the cost impacts associated with alternative control levels requiring a percent reduction in SO_2 emissions generally increase with decreasing annual capacity utilization factor because the fixed capital costs associated with the FGD system must be borne by a lower level of operation. Thus, cost impacts per unit of operation increase as annual capacity utilization factor decreases.

Tables 6-9 and 6-10 show that the steam generating unit annual capacity utilization factor has a significant impact on the average cost effectiveness of alternative control levels requiring a percent reduction in SO_2 emissions. For example, in Region V the average cost effectiveness of alternatives requiring a percent reduction in SO_2 emissions increases from $750 to $870/Mg ($680 to $790/ton) at an annual capacity utilization factor of 0.60 to $2,100 to $2,550/Mg ($1,910 to $2,320/ton) at an annual capacity utilization factor of 0.15. Similarly, in Region VIII the average cost effectiveness of alternative control levels based on a percent reduction in SO_2 emissions increases from $850 to $1,080/Mg ($770 to $980/ton) at an annual capacity utilization factor of 0.60 to $1,940 to $2,550/Mg ($1,760 to $2,320/ton) at an annual capacity utilization factor of 0.15.

Tables 6-9 and 6-10 also show that annual capacity utilization factor has a significant impact on the incremental cost effectiveness of alternative control levels requiring a percent reduction in SO_2 emissions compared to alternative control levels based on the use of low sulfur coal. For example, the incremental cost effectiveness of the least stringent alternative control level requiring a percent reduction in SO_2 emissions

TABLE 6-9. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT CAPACITY UTILIZATION FACTOR IN EPA REGION V

Percent Removal/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	50%/ 387(0.9)	50%/ 258(0.6)	70%/ 172(0.4)	90%/ 86(0.2)
	Range of Percent Reduction Requirements					
Increase in Capital Cost Over Baseline, percent						
CUF = 0.15	0	0	6	6	6	6
CUF = 0.30	0	0	6	6	6	6
CUF = 0.60	0	0	6	6	6	6
Increase in Annualized Cost Over Baseline, percent						
CUF = 0.15	1	1	9	9	9	10
CUF = 0.30	1	2	8	9	9	10
CUF = 0.60	1	3	7	8	8	10
Average Cost Effectiveness, \$/Mg(\$/ton)						
CUF = 0.15	340(310)	480(440)	2,550(2,320)	2,290(2,080)	2,100(1,910)	2,170(1,970)
CUF = 0.30	250(230)	440(400)	1,390(1,260)	1,280(1,160)	1,180(1,070)	1,290(1,170)
CUF = 0.60	300(270)	430(390)	850(770)	780(710)	750(680)	870(790)
Incremental Cost Effectiveness, \$/Mg(\$/ton)						
CUF = 0.15	340(310)	670(610)	10,620(9,650)	510(460)	0(0)	2,940(2,670)
CUF = 0.30	250(230)	670(610)	5,120(4,650)	510(460)	0(0)	2,570(2,340)
CUF = 0.60	300(270)	610(550)	2,600(2,360)	360(330)	220(200)	2,390(2,170)

TABLE 6-10. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT CAPACITY UTILIZATION FACTOR IN EPA REGION VIII

Range of Percent Reduction Requirements

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	50%/ 387(0.9)	50%/ 258(0.4)	70%/ 172(0.6)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent						
CUF = 0.15	0	0	5	5	5	5
CUF = 0.30	0	0	5	5	5	5
CUF = 0.60	0	0	5	5	5	5
Increase in Annualized Cost Over Baseline, percent						
CUF = 0.15	1	1	9	9	10	10
CUF = 0.30	1	1	11	11	11	11
CUF = 0.60	2	2	11	11	12	12
Average Cost Effectiveness, $/Mg($/ton)						
CUF = 0.15	340(310)	300(270)	2,550(2,320)	2,210(2,010)	2,100(1,910)	1,940(1,760)
CUF = 0.30	340(310)	240(220)	1,580(1,440)	1,380(1,250)	1,270(1,150)	1,200(1,090)
CUF = 0.60	390(350)	240(220)	1,080(980)	940(850)	900(820)	850(770)
Incremental Cost Effectiveness, $/Mg($/ton)						
CUF = 0.15	340(310)	220(200)	11,370(10,340)	0(0)	780(710)	0(0)
CUF = 0.30	340(310)	220(100)	6,820(6,200)	0(0)	0(0)	360(330)
CUF = 0.60	390(350)	60(50)	4,610(4,180)	0(0)	440(400)	190(170)

over the most stringent alternative control level based on the use of low sulfur coal is approximately $2,600/Mg ($2,360/ton) for an annual capacity utilization factor of 0.60 in Region V, but increases to $10,610/Mg ($9,650/ton) at an annual capacity utilization factor of 0.15. Similarly, in Region VIII the incremental cost effectiveness increases from $4,600/Mg ($4,180/ton) to $11,370/Mg ($10,340/ton).

6.1.2 90 Percent Reduction Requirement

The costs and cost impacts associated with each alternative control level were first examined for a coal-fired steam generating unit having a heat input capacity of 44 MW (150 million Btu/hour) and an annual capacity utilization factor of 0.60. This unit is representative of a typical industrial-commercial-institutional coal-fired steam generating unit. Table 6-11 summarizes the results of this cost analysis for Region V and Table 6-12 summarizes the results for Region VIII.

The alternative control levels based on the use of low sulfur coal to meet emission ceilings of 731 ng/J (1.7 lb/million Btu) or 516 ng/J (1.2 lb/million Btu) heat input are identical to those presented previously in Table 6-4. Therefore, the cost impacts of alternative control levels based on the use of low sulfur coal are not discussed in detail below. This discussion focuses mainly on the costs and cost impacts of alternative control levels based on a 90 percent reduction in SO_2 emissions.

Tables 6-11 and 6-12 show that the increase in capital costs associated with each alternative control level based on a 90 percent reduction in SO_2 emissions is about $0.7 to $0.8 million over the cost at the regulatory baseline. This represents an increase of about 5 percent in the capital costs for a typical 44 MW (150 million Btu/hour) heat input capacity coal-fired industrial-commercial-institutional steam generating unit.

The additional annualized costs for a typical 44 MW (150 million Btu/hour) heat input capacity coal-fired steam generating unit associated with the various alternative control levels requiring a 90 percent reduction in SO_2 emissions range from about $460,000 to $610,000 per year, depending

TABLE 6-11. COST IMPACTS OF A 44 MW (150 MILLION BTU/HOUR) COAL-FIRED STEAM GENERATING UNIT IN EPA REGION V

90 Percent Reduction Requirement

Alternative Control Level		"Least Cost" Approach						
Percent Reduction	SO_2 Emission Ceiling ng/J (lb/million Btu)	Percent Removal	Coal Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Annual Emissions Mg/yr (tons/yr)	Capital Cost $million	Annualized Cost $1,000/yr	Average Cost Effectiveness $/Mg($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
None	1,075 (2.5)	0	894 (2.08)	750 (830)	14.1	6,160	-	-
None	731 (1.7)	0	589 (1.37)	520 (570)	14.1	6,230	300 (270)	300 (270)
None	516 (1.2)	0	404 (0.94)	340 (370)	14.1	6,340	430 (390)	610 (550)
90	258 (0.6)	90	2,150 (5.00)	150 (170)	14.9	6,620	770 (700)	1,540 (1,400)
90	172 (0.4)	90	1,256 (2.92)	70 (80)	14.9	6,710	800 (730)	1,100 (1,000)
90	86 (0.2)	90	589 (1.37)	40 (40)	14.9	6,770	850 (770)	1,650 (1,500)

TABLE 6-12. COST IMPACTS OF A 44 MW (150 MILLION BTU/HOUR) COAL-FIRED STEAM GENERATING UNIT IN EPA REGION VIII

90 Percent Reduction Requirement

Alternative Control Level		"Least Cost" Approach						
Percent Reduction	SO_2 Emission Ceiling ng/J (lb/million Btu)	Percent Removal	Coal Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Annual Emissions Mg/yr (tons/yr)	Capital Cost $million	Annualized Cost $1,000/yr	Average Cost Effectiveness $/Mg($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
None	1,075 (2.5)	0	894 (2.08)	750 (830)	15.2	4,950	-	-
None	731 (1.7)	0	589 (1.37)	520 (570)	15.2	5,040	390 (350)	390 (350)
None	516 (1.2)	0	404 (0.94)	340 (370)	15.2	5,050	240 (220)	60 (50)
90	258 (0.6)	90	404 (0.94)	30 (30)	15.9	5,550	830 (750)	1,620 (1,470)
90	172 (0.4)	90	404 (0.94)	30 (30)	15.9	5,550	830 (750)	0 (0)
90	86 (0.2)	90	404 (0.94)	30 (30)	15.9	5,550	830 (750)	0 (0)

on the emission ceiling and steam generating unit location (i.e., Region V or Region VIII). This represents an increase in steam generating unit annualized costs of 7 to 12 percent over the annualized costs at the regulatory baseline.

Tables 6-11 and 6-12 show that the average cost effectiveness of alternative control levels requiring a 90 percent reduction in SO_2 emissions ranges from about \$770 to \$850/Mg (\$700 to \$770/ton) for a typical 44 MW (150 million Btu/hour) heat input capacity steam generating unit.

The incremental cost effectiveness of an alternative control level based on a 90 percent reduction in SO_2 emissions with an emission ceiling of 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input compared to a control alternative based on the use of low sulfur coal to meet an emission ceiling of 516 ng SO_2/J (1.2 lb SO_2/million Btu) is about \$1,540/Mg (\$1,400/ton) in Region V and about \$1,620/Mg (\$1,470/ton) in Region VIII. The incremental cost effectiveness to meet increasingly more stringent emission ceilings for alternative control levels based on a 90 percent reduction in SO_2 emissions is about \$1,100 to \$1,650/Mg (\$1,000 to \$1,500/ton) in Region V. In Region VIII, this incremental cost effectiveness is zero because coal with the same sulfur content would be used under all alternative control levels requiring a 90 percent reduction in SO_2 emissions.

The cost impacts of alternative control levels were also examined as a function of steam generating unit size. The results are summarized in Table 6-13 for Region V and Table 6-14 for Region VIII. These tables present the increases in capital costs, the increases in annualized costs, and the cost effectiveness of SO_2 control for typical 29, 44, 73, and 117 MW (100, 150, 250, and 400 million Btu/hour) heat input capacity steam generating units. As shown, the results and trends discussed above for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit generally apply to other steam generating unit sizes as well. As discussed previously, cost impacts of alternative SO_2 control levels based on the use of low sulfur coals change very little with respect to unit size. Cost impacts of alternative control levels requiring a 90 percent reduction in SO_2 emissions, however,

TABLE 6-13. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT SIZE IN EPA REGION V

90 Percent Reduction Requirement

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	90%/ 258(0.6)	90%/ 172(0.4)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent					
29 MW (100 million Btu/hour)	0	0	7	7	7
44 MW (150 million Btu/hour)	0	0	6	6	6
73 MW (250 million Btu/hour)	0	0	5	5	5
117 MW (400 million Btu/hour)	0	0	5	4	4
Increase in Annualized Cost Over Baseline, percent					
29 MW (100 million Btu/hour)	1	3	8	10	11
44 MW (150 million Btu/hour)	1	3	7	9	10
73 MW (250 million Btu/hour)	1	3	6	8	9
117 MW (400 million Btu/hour)	1	3	6	7	9
Average Cost Effectiveness, \$/Mg(\$/ton)					
29 MW (100 million Btu/hour)	320(290)	470(430)	930(840)	960(870)	990(900)
44 MW (150 million Btu/hour)	300(270)	430(390)	770(700)	800(730)	850(770)
73 MW (250 million Btu/hour)	330(300)	460(420)	650(590)	720(650)	770(700)
117 MW (400 million Btu/hour)	340(310)	460(420)	560(510)	640(580)	690(630)
Incremental Cost Effectiveness, \$/Mg(\$/ton)					
29 MW (100 million Btu/hour)	320(290)	670(610)	1,910(1,730)	1,230(1,120)	1,580(1,430)
44 MW (150 million Btu/hour)	300(270)	610(550)	1,540(1,400)	1,100(1,000)	1,650(1,500)
73 MW (250 million Btu/hour)	330(300)	640(580)	1,050(950)	1,230(1,120)	1,730(1,570)
117 MW (400 million Btu/hour)	340(310)	630(570)	770(700)	1,230(1,120)	1,680(1,520)

TABLE 6-14. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT SIZE IN EPA REGION VIII

90 Percent Reduction Requirement

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	90%/ 258(0.6)	90%/ 172(0.4)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent					
29 MW (100 million Btu/hour)	0	0	5	5	5
44 MW (150 million Btu/hour)	0	0	5	5	5
73 MW (250 million Btu/hour)	0	0	4	4	4
117 MW (400 million Btu/hour)	0	0	4	4	4
Increase in Annualized Cost Over Baseline, percent					
29 MW (100 million Btu/hour)	2	2	12	12	12
44 MW (150 million Btu/hour)	2	2	12	12	12
73 MW (250 million Btu/hour)	2	2	11	11	11
117 MW (400 million Btu/hour)	2	2	11	11	11
Average Cost Effectiveness, \$/Mg(\$/ton)					
29 MW (100 million Btu/hour)	390(350)	250(230)	930(840)	930(840)	930(840)
44 MW (150 million Btu/hour)	390(350)	240(220)	830(750)	830(750)	830(750)
73 MW (250 million Btu/hour)	390(350)	240(220)	740(670)	740(670)	740(670)
117 MW (400 million Btu/hour)	390(350)	250(230)	670(610)	670(610)	670(610)
Incremental Cost Effectiveness, \$/Mg(\$/ton)					
29 MW (100 million Btu/hour)	390(350)	90(80)	1,820(1,650)	0(0)	0(0)
44 MW (150 million Btu/hour)	390(350)	60(50)	1,620(1,470)	0(0)	0(0)
73 MW (250 million Btu/hour)	390(350)	70(60)	1,380(1,250)	0(0)	0(0)
117 MW (400 million Btu/hour)	390(350)	90(80)	1,210(1,100)	0(0)	0(0)

decrease with increasing steam generating unit size due to the economies of scale of FGD systems.

Steam generating unit size has the greatest impact on the incremental cost effectiveness between alternative control levels requiring a 90 percent reduction in SO_2 emissions and alternative control levels based on the use of low sulfur coal. For example, in Region V the incremental cost effectiveness of the least stringent alternative control level requiring a 90 percent reduction in SO_2 emissions over the most stringent alternative control level based on the use of low sulfur coal is about $1,900/Mg ($1,730/ton) of SO_2 removed for a 29 MW (100 million Btu/hour) heat input capacity steam generating unit. The incremental cost effectiveness decreases to $770/Mg ($700/ton) of SO_2 removed for a 117 MW (400 million Btu/hour) heat input capacity steam generating unit in Region V. Similarly, in Region VIII the incremental cost effectiveness decreases from $1,810/Mg ($1,650/ton) to $1,200/Mg ($1,100/ton) as steam generating unit size increases.

Finally, the cost impacts of the alternative control levels were examined as a function of the steam generating unit annual capacity utilization factor. The variations in cost impacts with annual capacity utilization factor were examined for 44 MW (150 million Btu/hour) heat input capacity steam generating units with annual capacity utilization factors of 0.15, 0.30, and 0.60 in Regions V and VIII. The results are summarized in Tables 6-15 and 6-16, respectively.

Cost impacts associated with alternative SO_2 control levels based on the use of low sulfur coal are essentially constant with respect to annual capacity utilization factor, because differences in fuel prices are independent of annual capacity utilization factor. However, the cost impacts associated with alternative control levels requiring a 90 percent reduction in SO_2 emissions generally increase with decreasing annual capacity utilization factor, as explained earlier.

Tables 6-15 and 6-16 show that steam generating unit annual capacity utilization factor has a significant impact on the average cost effectiveness of alternative control levels requiring a 90 percent reduction

TABLE 6-15. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT CAPACITY UTILIZATION FACTOR IN EPA REGION V

<u>90 Percent Reduction Requirement</u>

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	90%/ 258(0.6)	90%/ 172(0.4)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent					
CUF = 0.15	0	0	6	6	6
CUF = 0.30	0	0	6	6	6
CUF = 0.60	0	0	6	6	6
Increase in Annualized Cost Over Baseline, percent					
CUF = 0.15	1	1	9	10	10
CUF = 0.30	1	2	9	10	10
CUF = 0.60	1	3	8	9	10
Average Cost Effectiveness, \$/Mg(\$/ton)					
CUF = 0.15	340(310)	480(440)	2,130(1,930)	2,140(1,940)	2,140(1,940)
CUF = 0.30	250(230)	440(400)	1,270(1,150)	1,240(1,130)	1,270(1,150)
CUF = 0.60	300(270)	430(390)	770(700)	800(730)	850(770)
Incremental Cost Effectiveness, \$/Mg(\$/ton)					
CUF = 0.15	340(310)	670(610)	5,110(4,640)	2,260(2,050)	2,100(1,910)
CUF = 0.30	250(230)	670(610)	3,080(2,790)	1,370(1,240)	1,580(1,430)
CUF = 0.60	300(270)	610(550)	1,540(1,400)	1,100(1,000)	1,650(1,560)

TABLE 6-16. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT CAPACITY UTILIZATION FACTOR IN EPA REGION VIII

90 Percent Reduction Requirement

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	None/ 731(1.7)	None/ 516(1.2)	90%/ 258(0.6)	90%/ 172(0.4)	90%/ 86(0.2)
Increase in Capital Cost Over Baseline, percent					
CUF = 0.15	0	0	5	5	5
CUF = 0.30	0	0	5	5	5
CUF = 0.60	0	0	5	5	5
Increase in Annualized Cost Over Baseline, percent					
CUF = 0.15	1	1	10	10	10
CUF = 0.30	1	1	11	11	11
CUF = 0.60	2	2	11	11	12
Average Cost Effectiveness, \$/Mg(\$/ton)					
CUF = 0.15	340(310)	300(270)	1,870(1,700)	1,879(1,700)	1,870(1,700)
CUF = 0.30	340(310)	240(220)	1,190(1,080)	1,190(1,080)	1,190(1,080)
CUF = 0.60	390(350)	240(220)	830(750)	830(750)	830(750)
Incremental Cost Effectiveness, \$/Mg(\$/ton)					
CUF = 0.15	340(310)	220(200)	3,950(3,580)	0(0)	0(0)
CUF = 0.30	340(310)	110(100)	2,420(2,200)	0(0)	0(0)
CUF = 0.60	390(350)	60(50)	1,590(1,440)	0(0)	0(0)

in SO_2 emissions. For example, in Region V the average cost effectiveness of alternatives requiring a 90 percent reduction in SO_2 emissions increases from about $770 to $850/Mg ($700 to $770/ton) at an annual capacity utilization factor of 0.60 to about $2,130/Mg ($1,940/ton) at an annual capacity utilization factor of 0.15. In Region VIII, the average cost effectiveness increases from about 830/Mg ($750/ton) at an annual capacity utilization factor of 0.60 to $1,870/Mg ($1,700/ton) at an annual capacity utilization factor of 0.15.

Tables 6-15 and 6-16 also show that the annual capacity utilization factor has a significant impact on the incremental cost effectiveness of alternative control levels requiring a 90 percent reduction in SO_2 emissions compared to alternative control levels based on the use of low sulfur coal. For example, the incremental cost effectiveness of the least stringent alternative control level requiring a 90 percent reduction in SO_2 emissions over the most stringent alternative control level based on the use of low sulfur coal is approximately $1,540/Mg ($1,400/ton) at an annual capacity utilization factor of 0.60 in Region V, but increases to $5,100/Mg ($4,640/ton) at an annual capacity utilization factor of 0.15. Similarly, in Region VIII the incremental cost effectiveness increases from $1,580/Mg ($1,440/ton) at an annual capacity utilization factor of 0.60 to $3,940/Mg ($3,580/ton) at an annual capacity utilization factor of 0.15.

6.1.3 Summary of Analysis

The results of this cost analysis indicate that the impacts associated with alternative control levels based on the use of low sulfur coal are lower than those associated with alternative control levels requiring a percent reduction in SO_2 emissions. Furthermore, the impacts associated with alternative control levels based on the use of low sulfur coal are fairly constant with respect to steam generating unit size and annual capacity utilization factor because fuel prices do not change with respect to unit size or annual capacity utilization factor.

The impacts associated with alternative control levels requiring a percent reduction in SO_2 emissions, however, do vary as a function of steam generating unit location, size, and annual capacity utilization factor. Location and annual capacity utilization factor are the most important of these factors in determining these cost impacts. In locations where significant differences exist between the price of high or medium sulfur coal and low sulfur coal, the incremental cost effectiveness of alternative control levels based on a percent reduction in SO_2 emissions over alternative control levels based on the use of low sulfur coal is less than in locations where only small differences exist between the prices of high or medium sulfur coals and low sulfur coals. In locations where significant differences in prices exist, the fuel savings realized by switching from firing low sulfur coal to firing medium or high sulfur coal offsets, to some extent, the costs of the FGD systems installed to comply with a percent reduction requirement.

As annual capacity utilization factor decreases, the cost impacts associated with alternative control levels based on a percent reduction requirement increase significantly. The large capital costs associated with FGD systems installed to comply with a percent reduction requirement must be borne by a lower level of operation. The cost impacts of alternative control levels requiring a percent reduction in emissions also increase as steam generating unit size decreases.

In addition, the predicted cost impacts vary depending on the viewpoint used in developing alternative control levels based on percent reduction requirements. In this analysis, two viewpoints were examined. The first viewpoint resulted in a range of SO_2 percent reduction requirements; the second resulted in only a 90 percent reduction requirement. The average and incremental cost effectiveness of alternative control levels based on a 90 percent reduction in SO_2 emissions are generally lower than those based on a 50 or 70 percent reduction in SO_2 emissions. Table 6-17 illustrates this for various coal types in Regions V and VIII for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit. Table 6-17 shows that the differences in annualized costs among FGD systems operated at various

TABLE 6-17. COST EFFECTIVENESS OF SO_2 PERCENT REDUCTION REQUIREMENTS FOR A 44 MW (150 MILLION BTU/HR) COAL-FIRED STEAM GENERATING UNIT

Percent Reduction	Coal Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Annualized Cost $1,000/yr	Annual SO_2 Emissions, Mg/yr (tons/yr)	Cost Effectiveness, $/Mg ($/ton)	
				Average[a]	Incremental
Region V:					
Low Sulfur Coal	516(1.2)	6,340	340(370)	-	-
50 Percent		6,800	150(170)	2,480(2,250)	2,480(2,250)
70 Percent		6,820	90(100)	1,930(1,750)	310(280)
90 Percent		6,830	30(30)	1,560(1,420)	150(140)
Medium Sulfur Coal	1,075(2.5)	6,160	750(830)	-	-
50 Percent		6,680	350(380)	1,270(1,150)	1,270(1,150)
70 Percent		6,720	200(220)	1,010(920)	280(250)
90 Percent		6,760	50(60)	860(780)	280(250)
High Sulfur Coal	2,580(6.0)	5,700	1,980(2,180)	-	-
50 Percent		6,410	910(1,000)	660(600)	660(600)
70 Percent		6,520	530(580)	560(510)	260(240)
90 Percent		6,620	150(170)	510(460)	300(270)
Region VIII:					
Low Sulfur Coal	516(1.2)	5,050	340(370)	-	-
50 Percent		5,510	150(170)	2,480(2,250)	2,480(2,250)
70 Percent		5,530	90(100)	1,930(1,750)	310(280)
90 Percent		5,550	30(30)	1,600(1,450)	310(280)
Medium Sulfur Coal	1,075(2.5)	4,950	750(830)	-	-
50 Percent		5,470	350(380)	1,260(1,150)	1,260(1,150)
70 Percent		5,520	200(220)	1,030(940)	350(320)
90 Percent		5,560	50(60)	880(800)	280(250)

[a]Cost effectiveness compared to uncontrolled steam generating unit firing identical coal.

percent removal efficiencies are minimal, especially when compared to the increase in cost associated with the use of an FGD system over the use of medium or low sulfur coal to reduce SO_2 emissions. However, there is a substantial difference between the annual SO_2 emission reductions achieved by an FGD system operated at 90 percent emission reduction and one operated at 50 percent emission reduction. Thus, the cost effectiveness of achieving a 90 percent reduction in SO_2 emissions on any given coal type is lower than the cost effectiveness of achieving a 50 percent reduction in SO_2 emissions.

Table 6-18 summarizes the cost impacts associated with a 90 percent reduction requirement on coals with various sulfur contents in Regions V and VIII. As shown, the average cost effectiveness over the regulatory baseline of requiring a 90 percent reduction in SO_2 emissions ranges from about \$560/Mg (\$510/ton) to \$1,050/Mg (\$950/ton). The incremental cost effectiveness over the use of low sulfur coal to achieve an emission level of 516 ng/J (1.2 lb/million Btu) heat input ranges from \$770/Mg (\$700/ton) to \$2,050/Mg (\$1,860/ton).

Finally, it should be noted that the cost impacts discussed in the above analysis represent the "worse case" impacts that might be incurred by industrial-commercial-institutional steam generating units. As discussed earlier, steam generating unit operators may switch fuels in response to different SO_2 emission control requirements, thus avoiding many of the costs associated with the control of SO_2 emissions. The effect of fuel switching on the cost effectiveness of emission controls can be dramatic, as outlined below.

The costs presented above are presented on a before-tax annualized cost basis. The fuel choice decision for new industrial-commercial-institutional steam generating units, however, will most likely be made by determining the lowest after-tax net present value (NPV) of the cash outlays for capital, operating and maintenance, and fuel expenses over a fixed investment period. Thus, the effects of fuel switching must be examined on an after-tax NPV basis.

Table 6-19 illustrates the impact of fuel switching on costs, annual emissions, and cost effectiveness of emission controls. For example,

TABLE 6-18. COST IMPACTS FOR COAL-FIRED STEAM GENERATING UNITS IN REGIONS V AND VIII

90 Percent Reduction Requirement

			REGION V			REGION VIII		
				Cost Effectiveness, \$/Mg(\$/ton)			Cost Effectiveness, \$/Mg(\$/ton)	
Coal Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Percent Reduction Required	Annual Emissions Mg/yr (tons/yr)	Annualized Cost \$1,000/yr	Over Baseline	Over Low Sulfur Coal	Annualized Cost \$1,000/yr	Over Baseline	Over Low Sulfur Coal
29 MW (100 million Btu/hr):								
903(2.5)	0	500(550)	4,430	-	-	3,640	-	-
516(1.2)	0	230(250)	4,560	450(410)	-	3,710	240(220)	-
2,580(6.0)	90	100(110)	4,800	910(830)	1,900(1,730)	NA[a]	-	-
903(2.5)	90	35(40)	4,890	980(890)	1,760(1,600)	4,090	970(880)	2,050(1,860)
516(1.2)	90	20(20)	4,940	1,050(950)	1,830(1,660)	4,090	920(840)	1,820(1,650)
44 MW (150 million Btu/hr):								
903(2.5)	0	750(830)	6,160	-	-	4,950	-	-
516(1.2)	0	350(380)	6,340	450(410)	-	5,050	230(210)	-
2,580(6.0)	90	150(170)	6,620	770(700)	1,450(1,320)	NA	-	-
903(2.5)	90	50(60)	6,760	860(780)	1,450(1,320)	5,560	870(790)	1,780(1,620)
516(1.2)	90	30(30)	6,840	940(850)	1,560(1,420)	5,550	810(740)	1,580(1,440)
73 MW (250 million Btu/hr):								
903(2.5)	0	1,250(1,380)	10,430	-	-	8,200	-	-
516(1.2)	0	560(620)	10,750	460(420)	-	8,370	250(230)	-
2,580(6.0)	90	250(280)	11,080	640(580)	1,030(940)	NA	-	-
903(2.5)	90	90(100)	11,300	750(680)	1,180(1,070)	9,090	770(700)	1,510(1,370)
516(1.2)	90	45(50)	11,440	840(760)	1,310(1,190)	9,090	730(660)	1,350(1,230)
117 MW (400 million Btu/hr):								
903(2.5)	0	2,010(2,210)	15,200	-	-	11,560	-	-
516(1.2)	0	910(1,000)	15,700	460(420)	-	11,840	250(230)	-
2,580(6.0)	90	400(440)	16,100	560(510)	770(700)	NA	-	-
903(2.5)	90	150(170)	16,460	680(620)	1,000(910)	12,860	700(640)	1,350(1,230)
516(1.2)	90	70(80)	16,680	760(690)	1,160(1,050)	12,860	670(610)	1,220(1,110)

[a]NA = coal type not available.

TABLE 6-19. IMPACTS OF FUEL SWITCHING ON COST ANALYSIS[a]

Alternative Control Level	After-Tax Net Present Value ($1,000)	Before-Tax Annualized Cost ($1,000/year)	Annual Emissions Mg/year (tons/year)	Cost Effectiveness $/Mg($/ton)
516 ng/J (1.2 lb/million Btu)	17,840	5,360	250 (280)	--
90 Percent Removal	18,990	5,570	120 (130)	1,540 (1,400)
Natural Gas	18,660	4,440	0 (0)	0 (0)

[a]Based on a 44 MW (150 million Btu/hour) heat input capacity steam generating unit in EPA Region V with an annual capacity utilization factor of 0.45.

assuming that fuel choice decisions are based on the lowest cost after-tax NPV, a 44 MW (150 million Btu/hour) heat input capacity steam generating unit in Region V operating at an annual capacity utilization factor of 0.45 would fire low sulfur coal under an alternative control level based on the use of low sulfur coal. However, in response to an alternative control level requiring a 90 percent reduction in SO_2 emissions, this steam generating unit would switch to firing natural gas, since this represents the strategy with the lowest after-tax NPV which complies with this alternative control level.

The annualized costs of firing a low sulfur coal to meet an alternatve control level of 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input would be $5.36 million per year and annual SO_2 emissions would be 250 Mg SO_2/year (280 tons SO_2/year). The annualized costs of installing an FGD on a coal-fired steam generating unit in response to an alternative control level requiring a 90 percent reduction in SO_2 emissions would be $5.57 million and the annual SO_2 emissions would be 120 Mg SO_2/year (130 tons SO_2/year). The annualized costs of firing natural gas, however, would be $4.44 million per year and annual emissions would be zero. Thus, switching from coal to natural gas in response to an alternative control level requiring a 90 percent reduction in SO_2 emissions would result in a significant reduction in both annualized costs and annual SO_2 emissions. The incremental cost effectiveness of control would be reduced from $1,540/Mg ($1,400/ton) of SO_2 removed to zero due to this fuel switching.

This example shows that, under certain circumstances, steam generating unit owners and operators can avoid certain costs associated with SO_2 emission reduction requirements by switching to a cleaner fuel, rather than installing FGD control equipment. For this model steam generating unit cost analysis, however, it was assumed that all such owners and operators would install control technology. Consequently, the costs and cost effectiveness values cited should be viewed as "worse case" values.

6.2 COSTS OF SULFUR DIOXIDE EMISSION CONTROL FOR OIL-FIRED STEAM GENERATING UNITS

As with coal-fired steam generating units, there are two basic approaches that can be used to reduce SO_2 emissions from oil-fired steam generating units: the combustion of low sulfur oils, or the use of flue gas desulfurization (FGD) systems. Although sodium, dual alkali, lime, and limestone FGD systems are considered demonstrated for the purpose of developing NSPS for oil-fired industrial-commercial-institutional steam generating units, sodium scrubbing systems are the only FGD systems that have received widespread application to oil-fired steam generating units. Consequently, sodium scrubbing was used to represent the costs of FGD systems in this analysis.

In addition, this cost analysis focuses only on EPA Region V. The price of oil with a specific sulfur content varies on a regional basis; however, the price differential among oils with various sulfur contents remains essentially constant across all regions. For example, the price of a 344 ng SO_2/J (0.8 lb SO_2/million Btu) oil may vary substantially from one region to another, but the difference in price between a 344 ng SO_2/J (0.8 lb SO_2/million Btu) oil and a 688 ng SO_2/J (1.6 lb SO_2/million Btu) oil remains essentially the same. Therefore, although this analysis focuses only on Region V, the impacts associated with various alternative SO_2 control levels are representative of impacts in all regions.

Finally, as in the analysis discussed above for coal-fired steam generating units, the costs presented in this analysis for each of the alternative control levels discussed below are based on the "least cost" approach for complying with the requirements of that alternative. For example, to comply with an alternative control level based on the use of low sulfur oil, it may be less costly in some cases to fire a high sulfur oil and install an FGD system to reduce SO_2 emissions than it is to fire a low sulfur oil. In other words, the savings in annualized costs resulting from firing less expensive high sulfur oil may compensate for the cost of the FGD system.

As discussed in "Performance of Demonstrated Emission Control Technologies," SO_2 emissions could be reduced to 688 ng SO_2/J (1.6 lb SO_2/million Btu), 344 ng SO_2/J (0.8 lb SO_2/million Btu), and 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input through the use of low sulfur oils. To reduce emissions to less than 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input, however, the use of FGD is necessary.

As discussed previously, there are two viewpoints from which to approach the analysis of potential cost impacts associated with percent reduction requirements based on the use of FGD systems. One is that a range of percent reduction requirements merit consideration because FGD systems can be operated over a wide range of SO_2 removal efficiencies. Another is that a 90 percent reduction is the only percent reduction requirement that merits serious consideration because all of the demonstrated FGD systems are capable of achieving a 90 percent reduction in SO_2 emissions and current practice for industrial-commercial-institutional steam generating units is to design and install FGD systems capable of achieving this level of performance.

As mentioned above, the use of very low sulfur oil could reduce SO_2 emissions to 129 ng SO_2/J (0.3 lb SO_2/million Btu). Achieving a percent reduction of much less than 70 percent, however, would not reduce SO_2 emissions to less than 129 ng SO_2/J (0.3 lb SO_2/million Btu) on most oil types. Consequently, from the viewpoint that a range of percent reduction requirements should be considered, the lowest percent reduction requirement that merits consideration is 70 percent. As discussed earlier in "Performance of Demonstrated Emission Control Technologies," FGD systems are capable of reducing SO_2 emissions by 90 percent. This, therefore, represents the highest percent reduction requirement that merits consideration.

Combining these two percent reduction requirements with the maximum expected SO_2 emission rates associated with combustion of the various oils discussed in "Performance of Demonstrated Emission Control Technologies" results in the various SO_2 emission ceilings summarized in Table 6-20. As shown in this table, there are only two alternatives with SO_2 emission

TABLE 6-20. SO_2 EMISSION CEILINGS ASSOCIATED WITH VARIOUS PERCENT REDUCTION REQUIREMENTS

Oil Type	Maximum Expected SO_2 Emission Rate[a]	SO_2 Emission Ceiling[a]	
		70 Percent Reduction	90 Percent Reduction
Very Low Sulfur	129 (0.3)	43 (0.1)	22 (0.05)
Low Sulfur	344 (0.8)	86 (0.2)	43 (0.1)
Medium Sulfur	688 (1.6)	215 (0.5)	86 (0.2)
High Sulfur	1,290 (3.0)	387 (0.9)	129 (0.3)

[a]Emission rates and emission ceilings in ng SO_2/J (lb SO_2/million Btu) heat input.

ceilings associated with a 70 percent reduction requirement that would be more effective in reducing SO_2 emissions than the use of low sulfur oil: 86 ng SO_2/J (0.2 lb SO_2/million Btu) and 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input. These two alternatives, therefore, are the only two associated with a percent reduction requirement of 70 percent that merit consideration.

Assuming that a 90 percent emission reduction requirement should be more effective in reducing SO_2 emissions than a 70 percent emission reduction requirement, there is only one alternative associated with a 90 percent reduction requirement that merits consideration. As shown in Table 6-20, this alternative has an SO_2 emission ceiling of 22 ng SO_2/J (0.05 lb SO_2/million Btu) heat input.

This viewpoint that a range of percent reduction requirements should be considered, therefore, leads to three alternative percent reduction requirements: two alternatives associated with a 70 percent reduction requirement and one alternative associated with a 90 percent reduction requirement. The difference in the SO_2 emission ceilings associated with these three percent reduction requirements, however, is very small, only about 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input. Consequently, rather than examine all three alternative percent reduction requirements, only the 70 percent reduction requirement with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input was examined. This alternative is generally representative of all three percent reduction requirements.

Combining this alternative percent reduction requirement with the three alternatives mentioned above based on the use of low sulfur oil, in addition to the regulatory baseline, results in five alternative control levels for analysis under this viewpoint as summarized in Table 6-21.

As shown in Table 6-20, the alternative viewpoint that a 90 percent reduction requirement is the only percent reduction requirement that merits consideration results in only three alternatives with SO_2 emission ceilings of less than 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input. The SO_2 emission ceilings associated with these three alternatives happen to be the same as those discussed above: 86 ng SO_2/J (0.2 lb SO_2/million Btu), 43 ng

TABLE 6-21. ALTERNATIVE CONTROL LEVELS FOR OIL-FIRED INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

Range of Percent Reduction Requirements

Percent Reduction/ Emission Ceiling ng/J (lb/million Btu)	Control Method
None / 1290 (3.0)[a]	High Sulfur Oil
None / 688 (1.6)	Medium Sulfur Oil
None / 344 (0.8)	Low Sulfur Oil
None / 129 (0.3)	Very Low Sulfur Oil
70% / 43 (0.1)	FGD with 70% Removal

[a]Represents regulatory baseline.

SO_2/J (0.1 lb SO_2/million Btu), and 22 ng SO_2/J (0.05 lb SO_2/million Btu) heat input. Again, since the difference among these SO_2 emission ceilings is very small, only a 90 percent reduction requirement with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input was examined.

As summarized in Table 6-22, combining this alternative percent reduction requirement with the three alternatives mentioned above based on the use of low sulfur oil, in addition to the regulatory baseline, leads to essentially the same alternative control levels for analysis as those developed under the viewpoint that a range of percent reduction requirements merits consideration. The only difference between these two sets of alternative control levels is that a 70 percent reduction requirement is included in one set and a 90 percent reduction requirement is included in the other set. The SO_2 emission ceiling associated with these two percent reduction requirements, however, is the same. Thus, the difference in alternative control levels resulting from these two viewpoints for oil-fired steam generating units is minimal. As in the analysis of cost impacts on coal-fired steam generating units discussed above, however, both sets of alternative control levels were examined. For convenience, the alternative control levels resulting from the first viewpoint are referred to as "range of percent reduction requirements" and the alternative control levels resulting from the second viewpoint are referred to as "90 percent reduction requirement."

Finally, as mentioned in the above discussion of the cost impacts on coal-fired steam generating units, an SO_2 emission ceiling may preclude the combustion of certain oils. In this analysis of the cost impacts on oil-fired steam generating units, only one SO_2 emission ceiling was examined - 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input. This emission ceiling would preclude combustion of both high sulfur and medium sulfur oils, and would essentially require combustion of low sulfur oils.

TABLE 6-22. ALTERNATIVE CONTROL LEVELS FOR OIL-FIRED INDUSTRIAL-COMMERCIAL-INSTITUTIONAL STEAM GENERATING UNITS

90 Percent Reduction Requirement

Percent Reduction/ Emission Ceiling, ng/J (lb/million Btu)	Control Method
None / 1290 (3.0)[a]	High Sulfur Oil
None / 688 (1.6)	Medium Sulfur Oil
None / 344 (0.8)	Low Sulfur Oil
None / 129 (0.3)	Very Low Sulfur Oil
90% / 43 (0.1)	FGD with 90% Removal

[a]Represents regulatory baseline.

6.2.1 Range of Percent Reduction Requirements

The cost impacts associated with each alternative SO_2 control level were examined for an oil-fired steam generating unit having a heat input capacity of 44 MW (150 million Btu/hour) and an annual capacity utilization factor of 0.55. This unit is representative of a typical oil-fired industrial-commercial-institutional steam generating unit. Table 6-23 summarizes the results of this cost analysis.

Table 6-23 shows that the least cost approach to meeting an alternative SO_2 control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) is to fire a high sulfur oil and install an FGD system, rather than burn a very low sulfur oil. This result is explained by the high cost of a very low sulfur oil compared to high sulfur oil. The cost savings associated with firing a high sulfur oil outweigh the costs of an FGD system.

Table 6-23 also shows that the capital costs associated with alternative control levels based on the use of medium and low sulfur oil (but not for very low sulfur oil) are essentially the same as those for a steam generating unit at the regulatory baseline. An alternative control level requiring a percent reduction in SO_2 emissions, however, would increase the capital costs for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit by about \$0.8 million. This represents an increase in capital cost of about 25 percent over the regulatory baseline. For the reasons mentioned above, an alternative SO_2 control level based on the use of very low sulfur oil has essentially the same impact on capital costs as an alternative control level requiring a percent reduction in emissions.

An alternative control level of 688 ng SO_2/J (1.6 lb SO_2/million Btu) heat input, based on the use of medium sulfur oil, would increase the annualized costs for a typical 44 MW (150 million Btu/hour) heat input capacity steam generating unit by about \$220,000 per year. This represents an increase in annualized costs of about 5 percent over the regulatory baseline. An alternative control level of 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input, based on the use of low sulfur oil, would increase the annualized costs by about \$500,000 per year, an increase in annualized cost

TABLE 6-23. COST IMPACTS OF A 44 MW (150 MILLION BTU/HOUR) OIL-FIRED STEAM GENERATING UNIT IN EPA REGION V

Range of Percent Reduction Requirements

Alternative Control Level: Percent Reduction/ SO_2 Emission Ceiling ng/J (lb/million Btu)	"Least Cost" Approach: Percent Removal	"Least Cost" Approach: Oil Sulfur Content ng/SO_2/J (lb SO_2/million Btu)	Annual Emissions Mg/yr (tons/yr)	Capital Cost $million	Annualized Cost $1,000/yr	Average Cost Effectiveness $/Mg ($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
None/1290 (3.0)[a]	0	1,290 (3.0)	980 (1,080)	3.2	4,640	-	-
None/688 (1.6)	0	688 (1.6)	530 (580)	3.3	4,860	480 (440)	480 (430)
None/344 (0.8)	0	344 (0.8)	260 (290)	3.3	5,140	690 (630)	1,070 (970)
None/129 (0.3)	90	1,290 (3.0)	90 (100)	4.0	5,220	650 (590)	460 (420)
70 Percent/43 (0.1)	90	344 (0.8)	30 (30)	4.0	5,500	900 (820)	4,400 (4,000)

[a]Represent regulatory baseline.

of about 11 percent over the regulatory baseline. An alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu), based on the use of very low sulfur oil, would increase the annualized costs by about $580,000 per year, an increase of about 12 percent over the regulatory baseline.

An alternative control level requiring a 70 percent reduction in SO_2 emissions with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input would increase annualized costs by about $860,000 per year. This represents an increase of 18 percent over the regulatory baseline. An alternative control level requiring a 70 percent reduction in emissions with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input would require that a low or very low sulfur oil be fired. The cost of the FGD system coupled with the high cost of low or very low sulfur oil results in a substantial increase in cost over the regulatory baseline.

The average cost effectiveness of each alternative control level is also shown in Table 6-23. The average cost effectiveness is calculated as the difference in costs between an alternative control level and the regulatory baseline, divided by the difference in emissions between the alternative control level and the regulatory baseline. The average cost effectiveness associated with an alternative control level of 688 ng SO_2/J (1.6 lb SO_2/million Btu) heat input based on the use of medium sulfur oil is $480/Mg ($440/ton) of SO_2 removed. The average cost effectiveness associated with an alternative control level of 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input based on the use of low sulfur oil is approximately $690/Mg ($630/ton) of SO_2 removed. The average cost effectiveness associated with an alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input based on the use of very low sulfur oil is about $650/Mg ($590/ton) of SO_2 removed. The average cost effectiveness of an alternative control level requiring a 70 percent reduction in emissions with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input is about $900/Mg ($820/ton) of SO_2 removed.

The incremental cost effectiveness of SO_2 control was also examined. Incremental cost effectiveness is defined as the difference in cost between two alternative control levels divided by the difference in emissions between the two alternative control levels. The incremental cost effectiveness of an alternative control level of 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input, based on the use of low sulfur oil, compared to an alternative control level of 688 ng SO_2/J (1.6 lb SO_2/million Btu) heat input, based on the use of medium sulfur oil, is about $1,070/Mg ($970/ton) of SO_2 removed. The incremental cost effectiveness of an alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input, based on the use of very low sulfur oil, compared to an alternative control level of 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input, based on the use of low sulfur oil, is about $460/Mg ($420/ton) of SO_2 removed. As mentioned above, it is less costly to fire a high sulfur oil and install an FGD system to meet an SO_2 emission limit of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input than it is to fire a very low sulfur oil.

The incremental cost effectiveness of an alternative control level requiring a 70 percent reduction in SO_2 emissions with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input, compared to an alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input based on the use of very low sulfur oil, is about $4,400/Mg ($4,000/ton) of SO_2 removed. The high incremental cost effectiveness of an alternative SO_2 control level requiring a 70 percent reduction in SO_2 emissions is due to the SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input associated with this percent reduction requirement. This SO_2 emission ceiling is so low that it requires firing a low or very low sulfur oil in addition to installing an FGD system. If this SO_2 emission ceiling were increased to 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input, the incremental cost effectiveness of an alternative control level requiring a 70 percent reduction in SO_2 emissions would decrease to $0/Mg ($0/ton) of SO_2 removed. This alternative would then be the same as the alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input based on the use of very low sulfur oil.

The cost impacts of alternative control levels were also examined as a function of steam generating unit size. The results are summarized in Table 6-24. Table 6-24 presents the increase in capital costs, the increase

TABLE 6-24. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT SIZE IN EPA REGION V

Range of Percent Reduction Requirements

Percent Reduction/Emission Ceiling ng/J (lb/million Btu)	None/688 (1.6)	None/344 (0.8)	None/129 (0.3)	70 Percent/43 (0.1)
Increase in Capital Cost Over Baseline, Percent				
29 MW (100 million Btu/hour)	1	1	23	23
44 MW (150 million Btu/hour)	1	1	23	22
73 MW (250 million Btu/hour)	1	1	22	22
117 MW (400 million Btu/hour)	1	1	17	17
Increase in Annualized Cost Over Baseline, Percent				
29 MW (100 million Btu/hour)	4	10	13	19
44 MW (150 million Btu/hour)	5	11	12	18
73 MW (250 million Btu/hour)	5	11	11	17
117 MW (400 million Btu/hour)	5	9	10	16
Average Cost Effectiveness, \$/Mg (\$/ton)				
29 MW (100 million Btu/hour)	460 (420)	680 (620)	730 (660)	980 (890)
44 MW (150 million Btu/hour)	480 (440)	690 (630)	650 (590)	900 (820)
73 MW (250 million Btu/hour)	480 (440)	620 (560)	550 (500)	800 (740)
117 MW (400 million Btu/hour)	480 (440)	550 (500)	500 (450)	770 (700)
Incremental Cost Effectiveness, \$/Mg (\$/ton)				
29 MW (100 million Btu/hour)	460 (420)	1,050 (950)	910 (830)	4,190 (3,800)
44 MW (150 million Btu/hour)	480 (440)	1,070 (970)	460 (420)	4,400 (4,000)
73 MW (250 million Btu/hour)	480 (440)	840 (760)	260 (240)	4,710 (4,270)
117 MW (400 million Btu/hour)	480 (440)	680 (620)	240 (220)	4,640 (4,220)

in annualized costs, and the cost effectiveness of control for typical 29 MW, 44 MW, 73 MW, and 117 MW (100, 150, 250, and 400 million Btu/hour) heat input capacity steam generating units. As shown, the results and trends discussed above for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit generally apply to other steam generating unit sizes as well. Cost impacts of alternative control levels based on the use of medium or low sulfur oil change very little with respect to unit size. Cost impacts of alternative control levels based on the use of very low sulfur oil or alternative control levels requiring a 70 percent reduction in SO_2 emissions, however, decrease slightly with increasing steam generating unit size due to the economies of scale of FGD systems.

Finally, the cost impacts of alternative control levels were examined as a function of steam generating unit annual capacity utilization factor for a 44 MW (150 million Btu/hour) heat input capacity oil-fired steam generating unit. The results of this analysis are shown in Table 6-25. Cost impacts are examined for annual capacity utilization factors of 0.15, 0.30, and 0.55.

Capital costs for a given steam generating unit are fixed, regardless of the annual capacity utilization factor of the unit. However, operating and maintenance costs such as fuel costs, utility costs, raw materials, and waste disposal costs decrease with decreasing annual capacity utilization factor. Therefore, at low annual capacity utilization factors capital charges represent a larger percentage of the total annualized cost of control. As annual capacity utilization factor increases, however, capital charges become less important. Annual emissions, of course, are directly proportional to the annual capacity utilization factor of the steam generating unit.

The cost effectiveness associated with alternative SO_2 control levels based on the use of medium or low sulfur oil are essentially constant with respect to annual capacity utilization factor, because differences in fuel prices are independent of annual capacity utilization factor. However, the cost impacts associated with an alternative control level based on the use of very low sulfur oil or an alternative control level requiring a 70

TABLE 6-25. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT CAPACITY UTILIZATION FACTOR IN EPA REGION V

Range of Percent Reduction Requirements

Percent Reduction/Emission Ceiling ng/J (lb/million Btu)	None/688 (1.6)	None/344 (0.8)	None/129 (0.3)	70 Percent/43 (0.1)
Increase in Capital Cost Over Baseline, Percent				
CUF = 0.15	0	0	23	23
CUF = 0.30	0	1	23	23
CUF = 0.55	1	1	23	22
Increase in Annualized Cost Over Baseline, Percent				
CUF = 0.15	3	7	11	22
CUF = 0.30	4	9	14	20
CUF = 0.55	5	11	12	18
Average Cost Effectiveness, $/Mg ($/ton)				
CUF = 0.15	470 (430)	700 (640)	860 (780)	1,550 (1,410)
CUF = 0.30	480 (440)	690 (630)	850 (770)	1,100 (1,000)
CUF = 0.55	480 (440)	690 (630)	650 (590)	900 (820)
Incremental Cost Effectiveness, $/Mg ($/ton)				
CUF = 0.15	470 (430)	1,100 (1,000)	1,540 (1,400)	11,000 (10,000)
CUF = 0.30	480 (440)	1,040 (940)	1,540 (1,400)	4,410 (4,000)
CUF = 0.55	480 (440)	1,070 (970)	460 (420)	4,400 (4,000)

percent reduction in SO_2 emissions generally increase with decreasing annual capacity utilization factor.

The method of control used to comply with an alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input also changes with decreasing annual capacity utilization factor. At an annual capacity utilization factor of 0.55, it is less costly to fire a high sulfur oil and install an FGD system to reduce SO_2 emissions than it is to fire a very low sulfur oil to comply with this alternative control level. However, at annual capacity utilization factors of 0.15 and 0.30, this situation reverses, and it is less costly to fire a very low sulfur oil. At these lower annual capacity utilization factors, the capital cost charges associated with the use of an FGD system are more significant than the differences in fuel costs between high and very low sulfur oils.

The cost impacts associated with an alternative SO_2 control level requiring a 70 percent reduction in SO_2 emissions increase with decreasing capacity utilization factor because the fixed capital costs associated with the FGD system must be borne by a lower level of operation.

The incremental cost effectiveness of the alternative control levels also tends to improve as annual capacity utilization factor increases. Again, this trend is most apparent for the alternative SO_2 control level based on the use of very low sulfur oil or the alternative SO_2 control level requiring a 70 percent reduction in SO_2 emissions. For example, the incremental cost effectiveness of the alternative control level based on the use of very low sulfur oil to meet an emission limit of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input ranges from about \$460/Mg (\$420/ton) of SO_2 removed at an annual capacity utilization factor of 0.55 to \$1,540/Mg (\$1,400/ton) of SO_2 removed at an annual capacity utilization factor of 0.15. Similarly, the incremental cost effectiveness of the alternative control level requiring a 70 percent reduction in SO_2 emissions with an emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input ranges from about \$4,400/Mg (\$4,000/ton) of SO_2 removed at an annual capacity utilization factor of 0.55 to about \$11,000/Mg (\$10,000/ton) of SO_2 removed at an annual capacity utilization factor of 0.15.

6.2.2 90 Percent Reduction Requirement

The cost impacts associated with each alternative control level were examined for an oil-fired steam generating unit having a heat input capacity of 44 MW (150 million Btu/hour) and an annual capacity utilization factor of 0.55. As mentioned above, this unit is representative of a typical industrial-commercial-institutional steam generating unit. Table 6-26 summarizes the results of this cost analysis.

The alternative control levels based on the use of medium, low, and very low sulfur oils to meet emission limits of 688, 344, and 129 ng SO_2/J (1.6, 0.8 and 0.3 lb SO_2/million Btu) heat input, respectively, are identical to those presented previously in Table 6-22. Therefore, the cost impacts of alternative control levels based on the use of low sulfur oil will not be discussed in detail below. This discussion will focus mainly on the costs and cost impacts of an alternative control level based on a 90 percent reduction in SO_2 emissions.

An alternative control level requiring a 90 percent reduction in SO_2 emissions coupled with an emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input would increase the capital costs for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit by about \$0.8 million. This represents an increase in capital cost of about 25 percent over the regulatory baseline.

An alternative control level requiring a 90 percent reduction in SO_2 emissions with an emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input would increase the annualized costs of the steam generating unit by about \$860,000 per year. This represents an increase of about 18 percent over the regulatory baseline.

The average cost effectiveness of SO_2 emission control associated with each of the alternative control levels is also shown in Table 6-26. The average cost effectiveness associated with an alternative control level requiring a 90 percent reduction in SO_2 emissions with an emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input is about \$900/Mg (\$820/ton) of SO_2 removed.

TABLE 6-26. COST IMPACTS OF A 44 MW (150 MILLION BTU/HOUR) OIL-FIRED STEAM GENERATING UNIT IN EPA REGION V

90 Percent Reduction Requirement

Alternative Control Level	"Least Cost" Approach						
Percent Reduction/ SO_2 Emission Ceiling ng/J (lb/million Btu)	Percent Removal	Oil Sulfur Content ng/SO_2/J (lb SO_2/million Btu)	Annual Emissions Mg/yr (tons/yr)	Capital Cost $million	Annualized Cost $1,000/yr	Average Cost Effectiveness $/Mg ($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
None/1290 (3.0)[a]	0	1,290 (3.0)	980 (1,080)	3.2	4,640	-	-
None/688 (1.6)	0	688 (1.6)	530 (580)	3.3	4,860	480 (440)	-
None/344 (0.8)	0	344 (0.8)	260 (290)	3.3	5,140	690 (630)	1,070 (970)
None/129 (0.3)	90	1,290 (3.0)	90 (100)	4.0	5,220	650 (590)	460 (420)
90 Percent/43 (0.1)	90	344 (0.8)	30 (30)	4.0	5,500	900 (820)	4,400 (4000)

[a]Represents regulatory baseline.

The incremental cost effectiveness of SO_2 control was also examined. The incremental cost effectiveness of an alternative control level requiring a 90 percent reduction in SO_2 emissions with an emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input, compared to an alternative control level based on the use of very low sulfur oil is about $4,400/Mg ($4,000/ton) of SO_2 removed. As mentioned above, the high incremental cost of the alternative control level requiring a 90 percent reduction in SO_2 emissions is due to the SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input associated with this percent reduction requirement. This SO_2 emission ceiling is so low that it requires the firing of a low or very low sulfur oil in addition to the use of an FGD system. If the SO_2 emission ceiling were increased to 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input, the incremental cost effectiveness of an alternative control level requiring a 90 percent reduction in SO_2 emissions would decrease to $0/Mg ($0/ton). This alternative would then be the same as the alternative control level of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input based on the use of very low sulfur oil.

The cost impacts of alternative SO_2 control levels were also examined as a function of steam generating unit size. The results are summarized in Table 6-27. Table 6-27 presents the increase in capital costs, the increase in annualized costs, and the cost effectiveness of control for typical 29 MW, 44 MW, 73 MW and 117 MW (100, 150, 250 and 400 million Btu/hour) heat input capacity steam generating units. As shown, the results and trends discussed above for a 44 MW (150 million Btu/hour) heat input capacity steam generating unit generally apply to other steam generating unit sizes as well. Cost impacts of alternative control levels based on the use of low sulfur oil change very little with respect to unit size. Cost impacts of alternative control levels based on the use of very low sulfur oil or on a 90 percent reduction requirement, however, decrease slightly with increasing steam generating unit size due to the economies of scale of FGD systems.

Finally, the cost impacts of alternative SO_2 control levels were examined as a function of steam generating unit annual capacity utilization factor for a 44 MW (150 million Btu/hour) heat input capacity oil-fired

TABLE 6-27. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT SIZE IN EPA REGION V

90 Percent Reduction Requirement

Percent Reduction/Emission Ceiling ng/J (lb/million Btu)	None/688 (1.6)	None/344 (0.8)	None/129 (0.3)	90%/43 (0.1)
Increase in Capital Cost Over Baseline, Percent				
29 MW (100 million Btu/hour)	0	1	23	23
44 MW (150 million Btu/hour)	1	1	23	22
73 MW (250 million Btu/hour)	1	1	22	22
117 MW (400 million Btu/hour)	1	1	17	17
Increase in Annualized Cost Over Baseline, Percent				
29 MW (100 million Btu/hour)	5	10	12	19
44 MW (150 million Btu/hour)	5	11	11	18
73 MW (250 million Btu/hour)	5	11	10	17
117 MW (400 million Btu/hour)	5	9	10	16
Average Cost Effectiveness, $/Mg ($/ton)				
29 MW (100 million Btu/hour)	460 (420)	680 (620)	730 (660)	980 (890)
44 MW (150 million Btu/hour)	480 (440)	690 (630)	650 (590)	900 (820)
73 MW (250 million Btu/hour)	480 (440)	620 (560)	550 (500)	800 (740)
117 MW (400 million Btu/hour)	480 (440)	550 (500)	500 (450)	760 (690)
Incremental Cost Effectiveness, $/Mg ($/ton)				
29 MW (100 million Btu/hour)	460 (420)	1050 (950)	910 (830)	4180 (3800)
44 MW (150 million Btu/hour)	480 (440)	1070 (970)	460 (420)	4400 (4000)
73 MW (250 million Btu/hour)	480 (440)	840 (760)	260 (240)	4700 (4270)
117 MW (400 million Btu/hour)	480 (440)	680 (620)	240 (220)	4640 (4220)

steam generating unit. The results of this analysis are shown in Table 6-28. Cost impacts were examined for annual capacity utilization factors of 0.15, 0.30, and 0.55.

The cost impacts associated with an alternative control level based on the use of very low sulfur oil or an alternative control level requiring a 90 percent reduction in SO_2 emissions generally increase with decreasing annual capacity utilization factor. As discussed previously, the least cost approach to comply with an alternative control level based on the use of very low sulfur oil changes with respect to annual capacity utilization factor. At an annual capacity utilization factor of 0.55, it is less costly to install an FGD system and fire high sulfur oil than it is to fire a very low sulfur oil to meet an emission limit of 129 ng SO_2/J (0.3 lb SO_2/million Btu); at annual capacity utilization factors of 0.15 and 0.30, it is less costly to fire very low sulfur oil. The impacts associated with an alternative control level based on a 90 percent reduction in SO_2 emissions increase with decreasing annual capacity utilization factor because the fixed capital costs associated with the FGD system must be borne by a lower level of operation.

The averge cost effectiveness of an alternative control level requiring a 90 percent reduction in SO_2 emissions with an SO_2 emission ceiling of 43 ng SO_2/J (0.1 lb SO_2/million Btu) heat input increases from $880/Mg ($800/ton) to $1,550/Mg ($1,410/ton) of SO_2 removed as annual capacity utilization factor decreases.

The incremental cost effectiveness of the alternative control levels also tends to improve as annual capacity utilization factor increases. Again, this trend is most apparent for the alternative SO_2 control level requiring a 90 percent reduction in SO_2 emissions, compared to the alternative control level based on the use of very low sulfur oil.

6.2.3 Summary of Analysis

The results of this cost analysis indicate that the impacts associated with alternative SO_2 control levels based on the use of medium or low sulfur

TABLE 6-28. COST IMPACTS OF SO_2 CONTROL AS A FUNCTION OF STEAM GENERATING UNIT CAPACITY UTILIZATION FACTOR IN EPA REGION V

90 Percent Reduction Requirement

Percent Reduction/Emission Ceiling ng/J (lb/million Btu)	None/688 (1.6)	None/344 (0.8)	None/129 (0.3)	90%/43 (0.1)
Increase in Capital Cost Over Baseline, Percent				
CUF = 0.15	0	0	23	23
CUF = 0.30	0	1	23	23
CUF = 0.55	0	1	23	22
Increase in Annualized Cost Over Baseline, Percent				
CUF = 0.15	3	7	17	22
CUF = 0.30	4	9	15	20
CUF = 0.55	5	11	12	18
Average Cost Effectiveness, \$/Mg (\$/ton)				
CUF = 0.15	470 (430)	704 (640)	860 (780)	1550 (1410)
CUF = 0.30	480 (440)	690 (630)	850 (770)	1100 (1000)
CUF = 0.55	480 (440)	690 (630)	650 (590)	900 (820)
Incremental Cost Effectiveness, \$/Mg (\$/ton)				
CUF = 0.15	470 (430)	1100 (1000)	1540 (1400)	11000 (10000)
CUF = 0.30	480 (440)	1030 (940)	1540 (1400)	4410 (4000)
CUF = 0.55	480 (440)	1070 (970)	460 (420)	4400 (4000)

oil are lower than those associated with alternative control levels based on the use of very low sulfur oil or requiring a 90 percent reduction in SO_2 emissions. Furthermore, the impacts associated with alternative control levels based on the use of medium or low sulfur oil are fairly constant with respect to steam generating unit size and annual capacity utilization factor because fuel prices do not change with respect to unit size or annual capacity utilization factor.

Unlike the analysis of cost impacts on coal-fired steam generating units discussed above, the cost impacts on oil-fired steam generating units do not vary depending on the viewpoint used in developing alternative control levels based on percent reduction requirements. No matter which viewpoint is adopted, either a range of percent reduction requirements or a 90 percent reduction requirement, the cost impacts associated with alternative control levels based on percent reduction requirements are the same. This results from the fact that the SO_2 emission ceiling associated with the two percent reduction requirements examined in this analysis was the same. In addition, it was also low enough to effectively preclude combustion of medium and high sulfur oils and require combustion of low sulfur oil. As a result, the impacts associated with both the 70 percent and 90 percent reduction requirements were found to be the same.

In addition, there are only minimal cost differences among alternative control levels based on a percent reduction in SO_2 emissions even when considered independently of an associated emission ceiling. Table 6-29 shows that the differences in annualized costs among FGD systems operated over a range of percent removal efficiencies are minimal for low, medium, and high sulfur oils. However, there is a substantial difference between the annual SO_2 emission reductions achieved by a FGD system operated at 90 percent removal and one operated at 50 percent or 70 percent removal. As was found in the analysis of cost impacts for coal-fired steam generating units, an alternative control level based on a 90 percent reduction in SO_2 emissions is, therefore, more cost effective than alternative control levels requiring either a 50 percent or 70 percent reduction in SO_2 emissions.

TABLE 6-29. COST EFFECTIVENESS OF A RANGE OF PERCENT REDUCTION REQUIREMENTS FOR A 44 MW (150 MILLION BTU/HR) OIL-FIRED STEAM GENERATING UNIT IN REGION V

Percent Reduction	Oil Sulfur Content ng SO_2/J (lb $SO_2/10^6$ Btu)	Annualized Cost \$1,000/yr	Annual Emissions Mg/yr (tons/yr)	Cost Effectiveness \$/Mg (\$/ton) Removed	
				Average	Incremental
Low Sulfur Oil	344 (0.8)	5,140	262 (289)	-	-
50		5,470	100 (110)	2,040 (1,850)	2,040 (1,850)
70		5,485	60 (66)	1,710 (1,550)	375 (340)
90		5,500	20 (22)	1,490 (1,350)	375 (340)
Medium Sulfur Oil	688 (1.6)	4,860	524 (578)	-	-
50		5,250	200 (220)	1,205 (1,090)	1,205 (1,070)
70		5,280	120 (132)	1,060 (960)	375 (340)
90		5,310	40 (44)	930 (840)	375 (340)
High Sulfur Oil	1,290 (3.0)	4,640	983 (1,084)	-	-
50		5,100	372 (410)	760 (680)	760 (680)
70		5,160	223 (246)	685 (620)	400 (365)
90		5,220	74 (82)	640 (580)	400 (365)

For the typical oil-fired steam generating unit, unlike the typical coal-fired steam generating unit, the analysis also found that an alternative control level based on the use of very low sulfur fuel has essentially the same impact as an alternative control level based on a percent reduction requirement and having the same emission ceiling. This results from the fact that it is less costly to fire high sulfur oil and install an FGD system to reduce SO_2 emissions than to fire very low sulfur oil.

The cost effectiveness of alternative control levels based on percent reduction requirements, however, can be quite different from the cost effectiveness of an alternative control level based on the use of very low sulfur oil. If the SO_2 emission ceiling associated with the percent reduction requirement is low enough to effectively require the use of medium or low sulfur oil and preclude the use of high sulfur oil, the cost effectiveness of an alternative control level based on a percent reduction requirement is less attractive than that of an alternative control level based on the use of very low sulfur oil.

On the other hand, if the SO_2 emission ceiling is the same as that associated with the use of very low sulfur oil, then the average cost effectiveness of an alternative control level based on a percent reduction requirement is the same as that of an alternative control level based on the use of very low sulfur oil. In addition, the incremental cost effectiveness between an alternative control level based on a percent reduction requirement and an alternative control level based on the use of very low sulfur oil is zero.

For steam generating units with low annual capacity utilization factors, however, the impacts of an alternative control level based on a percent reduction requirement and the impacts of an alternative control level based on the use of very low sulfur oil are quite different. In this case, it is less costly to fire a very low sulfur oil than to fire a high sulfur oil and install an FGD system to reduce SO_2 emissions. Consequently, for oil-fired steam generating units with low annual capacity utilization factors, as with coal-fired steam generating units with low annual capacity utilization factors, the cost effectiveness of alternative control levels based on percent reduction requirements are always significantly less attractive than the cost effectiveness of an alternative control level based on the use of low sulfur fuels.

Table 6-30 summarizes the cost impacts associated with a 90 percent reduction requirement on high and low sulfur oils. The average cost effectiveness over the regulatory baseline ranges from approximately $500 to $950/Mg ($450 to $860/ton) of SO_2 removed. The incremental cost effectiveness of a 90 percent reduction requirement over the use of low sulfur oil to meet an emission limit of 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input ranges from $0 to $750/Mg ($0 to $680/ton) on high sulfur oil and from $970 to $1,740/Mg ($880 to $1,580/ton) on low sulfur oil.

The results of this cost analysis also show that at steam generating unit annual capacity utilization factors of 0.55 or greater, it is less costly to fire a high sulfur oil and install an FGD system to reduce SO_2 emissions than to fire a very low sulfur oil to meet an emission limit of 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input. At lower annual capacity utilization factors, however, it is less costly to fire very low sulfur oil.

For an alternative control level requiring a 90 percent reduction in SO_2 emissions or, in many cases, an alternative control level based on the use of very low sulfur oil, the cost impacts vary as a function of steam generating unit size and annual capacity utilization factor. Annual capacity utilization factor is the most important of these factors in determining the impacts. As the annual capacity utilization factor decreases, the cost impacts increase significantly. In addition, the cost impacts generally decrease with increasing steam generating unit size.

Finally, as mentioned above in the analysis of cost impacts on coal-fired steam generating units, the cost impacts discussed above represent the "worse case" impacts that might be incurred by oil-fired industrial-commercial-institutional steam generating units. As discussed previously, steam generating unit operators may switch fuels in response to an NSPS, thus avoiding many of the costs associated with control of SO_2 emissions. For example, a steam generating unit operator switching from oil

TABLE 6-30. COST IMPACTS FOR OIL-FIRED STEAM GENERATING UNITS IN REGION V

90 Percent Reduction Requirement

Oil Sulfur Content ng SO_2/J (lb SO_2/million Btu)	Percent Reduction Required	Annual Emissions Mg/yr (tons/yr)	Annualized Cost $1,000/yr	Cost Effectiveness, $/Mg ($/ton)	
				Over Baseline	Over Low Sulfur Oil
29 MW (100 million Btu/hr):					
1,290(3.0)	0	650(720)	3,260	-	-
344(0.8)	0	170(190)	3,580	680(620)	-
1,290(3.0)	90	50(60)	3,680	690(630)	750(680)
344(0.8)	90	20(20)	3,870	950(860)	1,740(1,580)
44 MW (150 million Btu/hr):					
1,290(3.0)	0	980(1080)	4,640	-	-
344(0.8)	0	260(290)	5,140	680(620)	-
1,290(3.0)	90	70(80)	5,200	620(560)	340(310)
344(0.8)	90	20(20)	5,480	870(790)	1,430(1,300)
73 MW (250 million Btu/hr):					
1,290(3.0)	0	1,630(1800)	7,380	-	-
344(0.8)	0	440(480)	8,220	690(630)	-
1,290(3.0)	90	130(140)	8,210	550(500)	0(0)
344(0.8)	90	40(40)	8,680	810(740)	1,140(1,040)
117 MW (400 million Btu/hr):					
1,290(3.0)	0	2,620(2890)	11,950	-	-
344(0.8)	0	700(770)	13,270	680(620)	-
1,290(3.0)	90	200(220)	13,140	500(450)	0(0)
344(0.8)	90	50(60)	13,890	760(690)	970(880)

to natural gas to avoid the costs of installing an FGD system would not only reduce the annualized costs associated with control of SO_2 emissions, but would also achieve greater reductions in SO_2 emissions. As a result, fuel switching can have a significant impact on the cost effectiveness of SO_2 emission control. Consequently, because the above discussion does not consider the possibility of fuel switching in response to alternative control levels, the costs and cost effectiveness values cited should be viewed as "worse case."

6.3 COSTS OF SULFUR DIOXIDE EMISSION CONTROL FOR MIXED FUEL-FIRED STEAM GENERATING UNITS

The SO_2 emissions resulting from combustion of wood, solid waste, and natural gas are negligible. As a result, SO_2 emissions from industrial-commercial-institutional steam generating units firing mixtures of coal or oil with nonfossil fuels such as wood or municipal solid waste, or even nonsulfur-bearing fossil fuels such as natural gas, are lower than SO_2 emissions from coal- or oil-fired steam generating units.

To comply with an alternative control level based on the use of low sulfur fuel, a coal- or oil-fired steam generating unit would be required to fire a low sulfur fuel or install an FGD system to reduce SO_2 emissions. As discussed in the analysis presented above, a coal- or oil-fired steam generating unit will generally choose to minimize costs and fire low sulfur fuel.

A mixed fuel-fired steam generating unit will also choose to minimize costs to comply with this same alternative control level. Because of the "dilution" of the SO_2 emissions resulting from combustion of coal or oil with the exhaust gases resulting from combustion of a nonsulfur-bearing fuel, however, a mixed fuel-fired steam generating unit will not fire a low sulfur fuel, if an emission credit is granted for the heat input to the steam generating unit from the nonsulfur bearing fuel. This steam generating unit will fire a medium or even high sulfur fuel.

A similar situation arises with alternative control levels requiring a percent reduction in SO_2 emissions. A coal- or oil-fired steam generating unit would be required to achieve the specific percent reduction requirement included in an alternative control level requiring such a reduction in SO_2 emissions. With an emission credit, however, a mixed fuel-fired steam generating unit would not be required to achieve this percent reduction requirement, but would be permitted to achieve a lower percent reduction requirement.

The merits of emission credits for mixed fuel-fired steam generating units, as well as the merits of emission credits for other types of steam generating units, are discussed in "Consideration of Emission Credits."

Assuming emission credits are not granted for mixed fuel-fired steam generating units, a mixed fuel-fired steam generating unit firing a mixture of coal or oil and other nonsulfur-bearing fuels can be considered a type of low annual capacity utilization factor coal- or oil-fired steam generating unit. To do this, the fossil fuel utilization factor of mixed fuel-fired steam generating units is defined as the actual annual heat input to the steam generating unit from coal or oil divided by the total maximum annual heat input to the unit if the unit were operated at design capacity for 24 hours per day, 365 days per year. For example, a steam generating unit firing 50 percent coal and 50 percent wood, and having an annual capacity utilization factor of 0.60, would have a fossil fuel utilization factor of 0.30. Emissions of SO_2 from a coal-fired steam generating unit operating at an annual capacity utilization factor of 0.3 and a mixed fuel-fired steam generating unit (e.g., coal/wood) operating at a fossil fuel utilization factor of 0.3 would be the same.

Without emission credits, the costs associated with alternative control levels based on the use of low sulfur fuels would be essentially the same for both fossil fuel-fired and mixed fuel-fired steam generating units. Both types of steam generating units would be required to fire low sulfur fuels or install FGD systems to reduce SO_2 emissions.

The costs associated with alternative control levels based on percent reduction requirements would also be essentially the same. In both cases, the FGD system would be designed and installed to handle the total exhaust gas volume from the steam generating unit. This would be necessary for the mixed fuel-fired steam generating unit, as well as the coal- or oil-fired steam generating unit, because the coal or oil fired in the mixed fuel-fired steam generating unit would represent 100 percent of the heat input when other fuels, such as wood, solid waste, and natural gas, are unavailable.

Similarly, the operating and maintenance costs would also be the same. These costs are primarily a function of the amount of SO_2 removed by the FGD system. This would be the same for both the mixed fuel-fired steam generating unit and the coal- or oil-fired steam generating unit.

Figure 6-1 illustrates these similarities in terms of the incremental cost effectiveness of a percent reduction requirement over a requirement based on the use of low sulfur fuel. As shown, the incremental cost effectiveness of SO_2 control for coal-fired steam generating units and mixed fuel-fired steam generating units are within the same range at all fossil fuel utilization factors. The variation in the incremental cost effectiveness shown in this figure for mixed fuel-fired steam generating units located in Regions I, IV, and X is the result of the wide variation in fuel types and prices among these regions and is not due to differences in the costs of flue gas desulfurization systems.

Without emission credits, therefore, the cost impacts on mixed fuel-fired steam generating units associated with alternative control levels based on the use of low sulfur fuels or requiring a percent reduction in SO_2 emissions are essentially the same as those discussed above for low annual capacity utilization factor coal- or oil-fired steam generating units.

6.4 COSTS OF PARTICULATE MATTER EMISSION CONTROL FOR OIL-FIRED STEAM GENERATING UNITS

As discussed in "Selection of Demonstrated Emission Control Technologies," there are three approaches that can be used to reduce particulate matter emissions from oil-fired industrial-commercial-

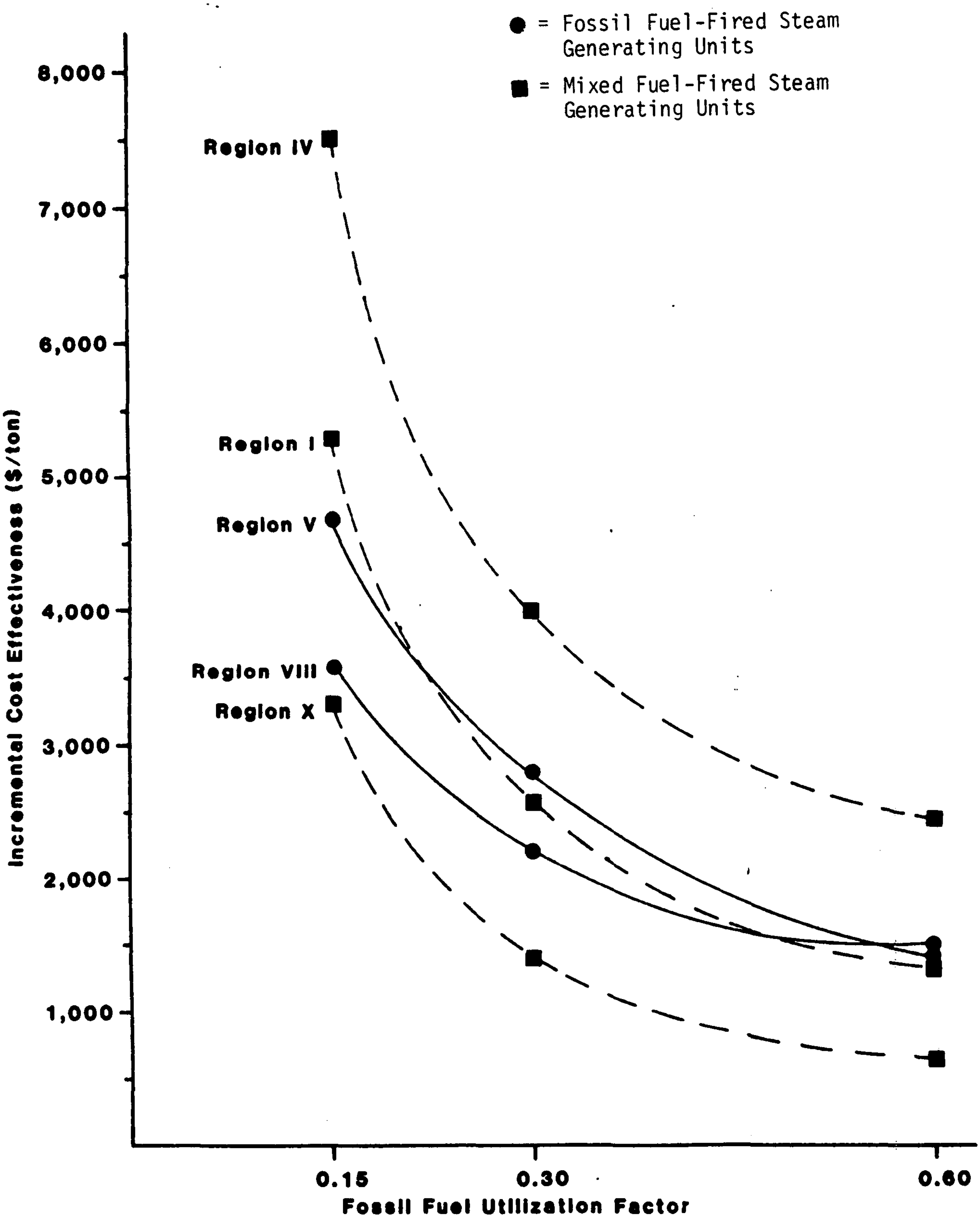

Figure 6-1. Incremental Cost Effectiveness of a Percent Reduction Requirement Over a Low Sulfur Fuel Requirement for 44 MW (150 Million Btu/Hour) Heat Input Capacity Coal-Fired and Mixed Fuel-Fired Steam Generating Units

institutional steam generating units. These are: the use of low sulfur oil to reduce both SO_2 and particulate matter emissions; the use of wet flue gas desulfurization (FGD) systems to reduce both SO_2 and particulate matter emissions; and the use of wet scrubbers or electrostatic precipitators (ESP's) to reduce particulate matter emissions only.

To analyze the potential cost impacts associated with limiting particulate matter emissions from new oil-fired industrial-commercial-institutional steam generating units, a regulatory baseline was developed. The regulatory baseline reflects the level of emission control that would be required in the absence of new source performance standards. An analysis of existing State implementation plans (SIP's) indicates that the average particulate matter emission limit for oil-fired industrial-commercial-institutional steam generating units is approximately 108 ng/J (0.25 lb/million Btu). This emission limit can generally be met even when firing high sulfur oil with no add-on controls. Therefore, the regulatory baseline selected was 108 ng/J (0.25 lb/million Btu) heat input, based on an uncontrolled oil-fired steam generating unit firing a high sulfur oil.

Costs for particulate matter controls were examined for a 44 MW (150 million Btu/hour) heat input capacity oil-fired steam generating unit with an annual capacity utilization factor of 0.55. This unit represents a typical oil-fired industrial-commercial-institutional steam generating unit. Table 6-31 presents the results of this cost analysis.

Table 6-31 shows that the capital cost for an oil-fired steam generating unit at the regulatory baseline is about \$3.2 million and the annualized cost is about \$4.66 million. Annual particulate matter emissions from a 44 MW (150 million Btu/hour) heat input capacity steam generating unit at the regulatory baseline are about 81 Mg/year (90 tons/year).

Costs associated with the use of low sulfur oil and the use of wet FGD systems to reduce SO_2 emissions are discussed above. Since these costs are all included under the cost of SO_2 control, the additional cost for particulate matter control is negligible. Thus, the average cost effectiveness of particulate matter control associated with use of these

TABLE 6-31. COST IMPACTS OF PARTICULATE MATTER CONTROL FOR A 44 MW (150 MILLION BTU/HOUR) OIL-FIRED STEAM GENERATING UNIT IN REGION V

Control Technique	Annual Emissions Mg/year (tons/year)	Capital Cost $Million	Annualized Cost $1,000/year	Average Cost Effectiveness $/Mg ($/ton)
High Sulfur Oil[a]	81 (90)	3.2	4,660	- -
Low Sulfur Oil[b]	33 (36)	3.2	5,150	0 (0)
Flue Gas Desulfurization[b]	33 (36)	4.0	5,220	0 (0)
Wet Scrubber	33 (36)	3.8	4,870	4,290 (3,900)
Electrostatic Precipitator	23 (25)	4.8	5,000	6,930 (6,300)

[a]Regulatory baseline.

[b]The cost of control can be attributed to SO_2 control; additional cost associated with particulate matter control is negligible.

emission control techniques is essentially zero. This is true regardless of steam generating unit size or annual capacity utilization factor.

Because control of SO_2 emissions also results in control of particulate matter emissions, the use of other particulate matter emission control technologies, such as wet scrubbers or ESP's, would not be necessary to reduce particulate matter emissions from oil-fired steam generating units. For completeness, however, the costs associated with these particulate matter control technologies are outlined below.

Installation of a wet scrubber or ESP to reduce particulate matter emissions from a 44 MW (150 million Btu/hour) heat input capacity oil-fired steam generating unit would increase capital costs over the regulatory baseline by about $550,000 for a wet scrubber and by about $1.6 million for an ESP. The increase in annualized costs over the regulatory baseline would be about $210,000 and about $340,000 per year, respectively. The average cost effectiveness of particulate matter control associated with the use of a wet scrubber would be about $4,280/Mg ($3,900/ton), and the average cost effectiveness associated with the use of an ESP would be about $6,940/Mg ($6,300/ton).

6.5 COSTS OF PARTICULATE MATTER EMISSION CONTROL FOR COAL-FIRED STEAM GENERATING UNITS EQUIPPED WITH FGD SYSTEMS

There are two alternatives that could be used to reduce particulate matter emissions from coal-fired steam generating units equipped with flue gas desulfurization systems for control of SO_2 emissions. These are: use of the FGD system to reduce emissions of particulate matter; or use of a fabric filter or an electrostatic precipitator upstream of the FGD system to reduce emissions of particulate matter.

The potential cost impacts associated with each of these alternatives were assessed. Costs were developed for a sodium FGD system and compared to the costs of installing a fabric filter upstream of this FGD system. As discussed in "Performance of Demonstrated Emission Control Technologies," wet scrubbing FGD systems are capable of reducing particulate matter emissions to 43 ng/J (0.1 lb/million Btu) heat input. A fabric filter, on the other hand, is capable of reducing particulate matter emissions to 21 ng/J (0.05 lb/million Btu) heat input. Costs of particulate matter control were examined for a typical 44 MW (150 million Btu/hour) heat input capacity steam generating unit operating at an annual capacity utilization factor of 0.6 in EPA Region V and firing coal with an average sulfur content of 2,380 ng SO_2/J (5.54 lb SO_2/million Btu) heat input.

The results of this analysis are presented in Table 6-32. The incremental annualized costs of installing and operating a fabric filter compared to using the FGD system alone to control particulate matter emissions are about $20,000. The incremental cost effectiveness of installing and operating a fabric filter for particulate matter control, therefore, compared to using the FGD system alone for particulate matter control, would be about $1,275/Mg ($1,160/ton) of particulate matter removed.

TABLE 6-32. COST IMPACTS OF PARTICULATE MATTER CONTROL FOR A 44 MW (150 MILLION BTU/HOUR) COAL-FIRED STEAM GENERATING UNIT IN REGION V

Control Technique	Annualized PM Emissions, Mg/yr (tons/yr)	Annualized Costs, $1,000/yr			Incremental Cost Effectiveness, $/Mg ($/ton) PM Removed
		SO_2 Control	PM Control	Total	
FGD, Combined PM/ SO_2 Control	36 (39)	786	399[a]	6434	-
FGD, SO_2 Control Alone FF, PM Control	18 (20)	786	420	6456	1,275 (1,160)[b]

[a]Cost of modifying the FGD for PM control.

[b]Over FGD for combined PM/SO_2 control.

7.0 CONSIDERATION OF SECONDARY ENVIRONMENTAL IMPACTS

Secondary environmental impacts associated with standards based on the use of low sulfur fuels or requiring a percent reduction in SO_2 emissions (i.e., based on the use of FGD systems) result primarily from the decrease in SO_2 emissions and the increase in liquid or solid wastes that may be generated from the use of various SO_2 control technologies. A related impact is an increase in the consumption of water resulting from the use of FGD systems.

As discussed in "Consideration of National Impacts," one of the results of a sulfur dioxide standard requiring a percent reduction in SO_2 emissions is fuel switching from coal and oil to natural gas. The secondary environmental impacts resulting from the increased liquid and solid wastes generated from the use of FGD discussed in this section would not occur at those facilities switching to natural gas. In addition, this fuel switching would result in a reduction in emissions of particulate matter and nitrogen oxides due to the lower emission levels of these pollutants resulting from combustion of natural gas.

7.1 AIR QUALITY IMPACTS

A dispersion analysis was performed to assess the ambient air quality impacts associated with standards based on the use of low sulfur fuel and standards requiring a percent reduction in SO_2 emissions. This analysis used the single source (CRSTER) model to estimate the ambient air concentrations of SO_2 resulting from each control alternative for model coal- and oil-fired steam generating units. Estimated maximum downwind ambient air SO_2 concentrations were calculated on an annual average and 24-hour average basis for a typical steam generating unit with a heat input capacity of 44 MW (150 million Btu/hour).

As a basis for the dispersion analysis, it was assumed that: (1) the pollutants displayed the dispersion behavior of a non-reactive gas; (2) all sources were located on flat or gently rolling terrain in urban areas;

(3) the model coal-fired steam generating unit was operated at a capacity utilization factor of 0.6 and the model oil-fired steam generating unit was operated at a capacity utilization factor of 0.55; (4) the stack height of each model steam generating unit was 53 meters (175 feet); (5) the stack gas temperature was 150°C (300°F) for units without FGD and 52°C (125°F) for units with FGD; (6) all model steam generating unit stacks were modeled as continuous point sources of emissions; (7) receptors were located at the same elevation as the base of the stack; and (8) 1964 meteorological data for St. Louis were used.

Table 7-1 presents the maximum downwind ambient air SO_2 concentrations as predicted by the single source (CRSTER) model and compares them to the ambient air SO_2 concentrations allowed under the National Ambient Air Quality Standards (NAAQS) and the Prevention of Significant Deterioration (PSD) Class II deterioration increments. The predicted ground level ambient air concentrations resulting from SO_2 control under both regulatory alternatives were all below the NAAQS, with maximum annual SO_2 concentrations ranging from 1.1 to 2.1 percent of the annual standard and maximum 24-hour SO_2 concentrations ranging from 3.3 to 6.2 percent of the 24-hour standard. The ambient air SO_2 concentrations resulting from SO_2 control under both regulatory alternatives were also below the PSD Class II deterioration increments, with maximum annual ambient air SO_2 concentrations ranging from 4.3 to 8.3 percent of the annual PSD increment and maximum 24-hour SO_2 concentrations ranging from 13.3 to 25 percent of the 24-hour PSD increment.

The data for both coal- and oil-fired steam generating units also indicate that ambient air concentrations of SO_2 decrease significantly in going from baseline control levels to control levels reflecting either the use of low sulfur fuel or a percent reduction in SO_2 emissions. If a steam generating unit equipped with FGD achieved the same SO_2 emission rate as a steam generating unit firing low sulfur fuel, higher ambient air SO_2 concentrations would result from the steam generating unit equipped with FGD. The lower gas temperature associated with the use of FGD reduces the gas plume buoyancy, thereby reducing dispersion of the pollutants emitted

TABLE 7-1. SO_2 DISPERSION ANALYSIS

		Maximum Downwind Ambient Concentration, $\mu g/m^3$ (10^{-6} gr/dscf)					
Fuel	Regulatory Alternative	Annual Mean	Percent of NAAQS[a]	Percent of PSD Increment[b]	24-Hour	Percent of NAAQS[c]	Percent of PSD Increment[d]
Coal	Regulatory Baseline 1,076 ng SO_2/J (2.5 lb $SO_2/10^6$ Btu)	3.46 (1.49)	4.3	17.3	43.85 (18.93)	12.0	48.2
	Low Sulfur Coal 516 ng SO_2/J (1.2 lb $SO_2/10^6$ Btu)	1.66 (0.72)	2.1	8.3	21.05 (9.09)	5.8	23.1
	Percent Reduction 90% Reduction and 258 ng SO_2/J (0.6 lb $SO_2/10^6$ Btu)	1.59 (0.69)	2.0	7.9	22.74 (9.82)	6.2	25.0
Oil	Regulatory Baseline 1,291 ng SO_2/J (3.0 lb $SO_2/10^6$ Btu)	4.50 (1.94)	5.6	22.5	55.99 (24.17)	15.3	61.5
	Low Sulfur Oil 344 ng SO_2/J (0.8 lb $SO_2/10^6$ Btu)	1.20 (0.52)	1.5	6.0	14.93 (6.45)	4.1	16.4
	Percent Reduction 90% Reduction and 129 ng SO_2/J (0.3 lb $SO_2/10^6$ Btu)	0.86 (0.37)	1.1	4.3	12.10 (5.22)	3.3	13.3

[a] SO_2 NAAQS (annual mean) = 80 $\mu g/m^3$ (34.54×10^{-6} gr/dscf).

[b] PSD Class II increment (annual mean) = 20 $\mu g/m^3$ (8.64×10^{-6} gr/dscf).

[c] SO_2 NAAQS (maximum 24-hr) = 365 $\mu g/m^3$ (157.60×10^{-6} gr/dscf).

[d] PSD Class II increment (maximum 24-hr) = 91 $\mu g/m^3$ (39.29×10^{-6} gr/dscf).

from the stack. However, as shown in Table 7-1, ambient air SO_2 concentrations are reduced to approximately the same level through the use of either SO_2 control alternative. This is because standards requiring a percent reduction in SO_2 emissions through the use of FGD generally achieve lower SO_2 emission rates than can be achieved through the use of low sulfur fuel. In addition, the positive air quality benefits associated with the larger SO_2 emission reductions achievable at the national level through standards requiring a percent reduction in SO_2 emissions should also be considered when assessing the secondary air quality impacts of alternative standards.

7.2 WATER QUALITY AND SOLID WASTE IMPACTS

Industrial-commercial-institutional steam generating units are generally part of a manufacturing plant and serve primarily in an auxiliary role. The plant's production processes typically result in the generation of substantial amounts of various wastes as well as the utilization of large amounts of water. Therefore, the amount of waste generated by control of SO_2 emissions from the steam generating unit(s) and the amount of water demanded by the FGD system(s) required to comply with percent reduction requirements frequently would represent only a small portion of the total plant waste generation and water demand.

7.2.1 Low Sulfur Fuels

The wastes generated from the combustion of low sulfur fuel to reduce SO_2 emissions are generally in dry ash form. The type and quantity of wastes produced vary depending on the type of fossil fuel fired, its ash content, and the method of producing and refining the fuel prior to firing.

The waste produced by coal-fired steam generating units consists of two fractions, fly ash and bottom ash. Fly ash, which accounts for the majority of the waste, is the fine ash fraction that is carried out of the steam generating unit in the flue gas. Fly ash is collected along with other particulate emissions by mechanical collectors, electrostatic precipitators, fabric filters, or wet scrubbers such as high pressure venturi scrubbers. The bottom ash, consisting of the larger and heavier combustion products and unburned residuals, drops to the bottom of the steam generating unit and is collected either as dry bottom ash or as slag.

For both fly ash and bottom ash, more than 80 percent of the total ash weight consists of silica, alumina, iron oxide, and lime (calcium oxide). Table 7-2 presents typical compositions of fly ash from eastern and western bituminous coals and western subbituminous coal. As shown in the table, the two most prominent components are silicon dioxide and aluminum oxide, which together comprise over 75 percent of the total ash by weight of the eastern and western bituminous coals. For western subbituminous coal, these two components plus calcium oxide (lime) make up over 80 percent of the total ash by weight.

Fly ash and bottom ash also contain small amounts of trace metals, as shown in Table 7-3. The types and amounts of these elements will vary greatly depending on the type of fuel fired, fuel handling procedures, and steam generating unit operating parameters. For coal-fired steam generating units, certain elements such as boron, chlorine, selenium, and arsenic may be present at levels greater than the average concentration in the earth's crust. These elements tend to collect in greater quantities in the fly ash than in the bottom ash. In general, elemental concentrations tend to be higher in eastern coals than in western coals.

Both bottom ash and fly ash are frequently disposed of in a pond disposal area. Typically, the ash is sluiced to a central disposal pond where the ash is allowed to settle out and the overflow liquor discharged or returned for sluicing. This pond liquor generally has a dissolved solids content on the order of hundreds of ppm, with the major constituents being calcium, magnesium, sodium, sulfate, and chloride, and lesser amounts of silicates, iron, manganese, and potassium.

As much as 20 percent of fly ash can be water soluble, raising the potential for leaching of certain constituents, notably calcium, magnesium, potassium, sulfate, and chloride. This, however, can be prevented by using

TABLE 7-2. TYPICAL COMPONENTS OF FLY ASH

Compound	Mean Weight Percent		
	Eastern Bituminous Coal	Western Bituminous Coal	Western Subbituminous Coal
SiO_2	48.76	49.69	40.2
Al_2O_2	23.26	23.04	21.8
Fe_2O	16.44	6.48	9.7
CaO	2.88	13.81	19.4
P_2O_5	2.73	0.38	0.4
K_2O	2.53	0.99	0.3
TiO_2	1.45	1.09	0.8
MgO	1.24	2.96	5.4
SO_3	0.78	1.66	-
Na_2O	0.53	1.04	2.0

TABLE 7-3. TRACE CONSTITUENTS IN FLY ASH AND BOTTOM ASH FROM VARIOUS UTILITY STEAM GENERATING UNITS

	Fly Ash Concentration (ppm)							Bottom Ash Concentration (ppm)						
Element	#1	#2	#3	#4	#5	#6	Mean	#1	#2	#3	#4	#5	#6	Mean
Arsenic	12	8	15	6	8.4	110	27	1	1	3	2	5.8	18	5
Beryllium	4.3	7	3	7	8.0	NR[a]	5.9	3	7	2	5	7.3	NR	4.9
Boron	266	200	300	700	NR	NR	367	143	125	70	300	NR	NR	160
Cadmium	0.5	0.5	0.5	1.0	6.44	8.0	2.8	0.5	0.5	0.5	1.0	1.08	1.1	0.8
Chromium	20	50	150	30	206	300	126	15	30	70	30	124	152	70
Cobalt	7	20	15	15	6.0	39	17	7	12	7	7	3.6	20.8	10
Copper	54	128	69	75	68	140	89	37	48	33	40	48	20	38
Fluoride	140	100	610	250	624	NR	345	50	50	100	85	10.6	NR	59
Lead	70	30	30	70	32	8.0	40	27	30	20	30	8.1	6.2	20
Mercury	0.07	0.01	0.03	0.08	20.0	0.05	3.37	0.01	0.01	0.01	0.01	0.51	0.03	0.10
Manganese	267	150	150	100	249	298	202	366	700	150	100	229	295	307
Nickel	10	50	70	20	134	207	82	10	22	15	10	62	85	34
Selenium	6.9	7.9	18.0	12.0	26.5	25	16.1	0.2	0.7	1.0	1.0	5.6	0.1	1.4
Vanadium	90	150	150	100	341	440	212	70	85	70	70	353	260	151
Zinc	63	50	71	103	352	740	230	24	30	27	45	150	100	63

[a]NR = not reported.

a lined disposal pond. In addition, fly ash possesses a high pozzolanic potential; it tends to aggregate and harden when moistened and compacted with lime and water. Due to this pozzolanic activity, a significant fraction (approximately 10 percent) of the fly ash generated is used for such purposes as soil or sludge stabilization, ice control, or as ingredients in cement, concrete, and blasting compounds. Bottom ash does not exhibit pozzolanic properties.

Dry ash can also be disposed of in managed landfills or dry impoundments. In this method, the wastes are collected and transported to the disposal area, then spread and compacted by physical means (e.g., bulldozing). Surface mine disposal may also be used for dry ash wastes. This may be done in one of three ways: disposal on the working pit floor prior to the return of overburden, dumping in spoil banks prior to reclamation, or mixing with overburden before returning it to the pit.

The constituents of coal ash are not considered a hazardous waste under the Resource Conservation and Recovery Act (RCRA). These wastes have been specifically exempted from characterization as hazardous by 40 CFR 261.4(b).

As mentioned above, the high solubility of some fly ash constituents creates a potential for the leaching of these constituents from the settling pond or landfill. This can be controlled, however, by the use of impermeable liners in the pond or landfill. After the settling out of the ash, the pond liquor typically contains total dissolved solids in the hundreds of ppm range, which consist primarily of calcium, magnesium, sodium, sulfate, and chloride with lesser amounts of silicates, iron, manganese, and potassium. When this pond liquor is diluted by combining it with other plant wastes prior to disposal, the concentrations of these substances are negligible.

In the absence of new source performance standards limiting emissions of SO_2 from new industrial-commercial-institutional steam generating units, most new coal-fired steam generating units in the east would probably fire medium sulfur eastern bituminous coals. Secondary environmental impacts in the east resulting from standards based on the use of low sulfur coal would depend on the source of the low sulfur coal fired. Firing low sulfur bituminous coal in the east would result in no additional secondary environmental impacts over the combustion of medium sulfur coal, as the types of waste generated and the method of disposal would remain the same. The process of cleaning medium sulfur coal to produce a low sulfur coal would also result in no additional secondary environmental impacts. Cleaning the coal would essentially move some of the wastes from the steam generating unit to the coal cleaning plant, but would generate no new wastes.

In the absence of standards, most new coal-fired steam generating units in the west would fire low sulfur subbituminous coal. Therefore, there would be little or no secondary environmental impacts associated with standards based on the use of low sulfur coal in the west.

Fuel oils fired by industrial-commercial-institutional steam generating units are processed in refineries to meet specifications set forth by the American Society for Testing and Materials (ASTM). Table 7-4 presents typical concentrations of various elements in unprocessed crude oil. Crude oil has a low ash content, and the amounts of trace metals present in fuel oil fired at a steam generating unit are much less than the levels at a coal-fired steam generating unit. At the refinery, fuel oils are typically processed using hydrodesulfurization to remove much of the sulfur content.

In the absence of standards, most steam generating units would fire medium sulfur fuel oil. The differences in refinery processing to produce a low sulfur oil compared to a medium sulfur oil would result in some additional waste generation at the refinery, but the amount of this additional waste would be extremely small compared to the total waste output at a typical refinery producing gasoline, home heating oil, diesel fuel, and other products in addition to the fuel oil supplied to industrial-commercial-institutional steam generating units. The removal of sulfur from oil in this manner is a routine practice and will not result in the generation of a new waste. Therefore, the secondary environmental impacts associated with standards based on the use of low sulfur oil would be negligible.

TABLE 7-4. ELEMENTAL COMPOSITION OF CRUDE OIL

Element	Range (%)
Carbon	83 - 87
Hydrogen	11 - 14
Sulfur	0 - 5
Nitrogen	0 - 0.88
Oxygen	0 - 2
Ash[a]:	0.01 - 0.05
Iron	
Calcium	
Magnesium	
Silicon	
Aluminum	
Vanadium	
Nickel	
Copper	
Manganese	
Strontium	
Barium	
Boron	
Cobalt	
Zinc	
Molybdenum	
Lead	
Tin	
Sodium	
Potassium	
Phosphorus	
Lithium	

[a]Elements present in the ash fraction are presented in decreasing concentrations.

7.2.2 Percent Reduction

The quantity of wastes associated with standards requiring a percent reduction in SO_2 emissions depends on several factors, including the sulfur and ash content of the fuel, applicable emission limits, the types of ash collection and FGD systems employed, and the FGD and steam generating unit operating conditions. Table 7-5 presents estimated quantities of waste that would be produced annually by various FGD systems on a steam generating unit with a heat input capacity of 44 MW (150 million Btu/hour) and an annual capacity utilization factor of 0.60 and the amount of waste produced by uncontrolled steam generating units.

The quantities of waste produced by FGD systems are small compared with the total amount produced by a typical industrial plant. For example, a typical iron and steel manufacturing plant would produce between 2.7 million and 11.5 million cubic meters (96 million and 410 million cubic feet) of wastewater per year and a typical petroleum refinery would produce approximately 1.2 million cubic meters (43 million cubic feet) of wastewater per year. In comparison, the use of sodium scrubbing to control SO_2 emissions from the steam generating units at a typical iron and steel manufacturing plant with a total steam generating unit heat input capacity of 215 MW (736 million Btu/hour) would produce approximately 252,000 cubic meters (9 million cubic feet) of wastewater per year if high sulfur coal is fired and 56,000 cubic meters (2 million cubic feet) of wastewater per year if low sulfur coal is fired. The use of sodium scrubbing to control SO_2 emissions from the steam generating units at a typical petroleum refinery with a total steam generating unit heat input capacity of 380 MW (1,300 million Btu/hour) would produce approximately 336,000 cubic meters (12 million cubic feet) of wastewater per year if high sulfur oil is fired and 98,000 cubic meters (3.5 million cubic feet) of wastewater per year if low sulfur oil is fired. Thus, the wastewater produced from sodium scrubbing would constitute from 0.5 to 9 percent of the total wastewater from a typical iron and steel manufacturing plant and from 8 to 28 percent of the total wastewater from a typical petroleum plant.

TABLE 7-5. QUANTITY OF WASTE PRODUCED BY VARIOUS FGD SO_2 CONTROL SYSTEMS

Fuel Type	FGD System[b]	Quantity of Waste Produced[a] Mass Mg/yr (tpy)	Volume 1,000 m^3/yr (1,000 ft^3/yr)
High Sulfur Coal[c]	None[g]	3,630 (4,000)	9.0 (315)
	Sodium	56,000 (61,700)	56.0 (1,980)
	Dual Alkali	6,810 (7,500)	5.2 (180)
	Dry Lime	6,600 (7,270)	5.5 (200)
Low Sulfur Coal[d]	None[g]	3,180 (3,500)	9.0 (315)
	Sodium	11,000 (12,150)	11.0 (390)
	Dual Alkali	1,170 (1,290)	0.8 (30)
	Dry Lime	2,090 (2,310)	1.8 (60)
High Sulfur Oil[e]	None[g]	18 (20)	9.0 (315)
	Sodium	31,000 (34,100)	31.0 (1,090)
Low Sulfur Oil[f]	None[g]	18 (20)	9.0 (315)
	Sodium	9,300 (10,300)	9.3 (330)

[a] Based on a 44 MW (150 million Btu/hour) heat input capacity steam generating unit with an annual capacity utilization factor of 0.60.

[b] Sodium = liquid waste
Dual alkali = sludge waste
Dry lime = dry solid waste

[c] 2580 ng SO_2/J (6.0 lb SO_2/million Btu).

[d] 516 ng SO_2/J (1.2 lb SO_2/million Btu).

[e] 1290 ng SO_2/J (3.0 lb SO_2/million Btu).

[f] 344 ng SO_2/J (0.8 lb SO_2/million Btu).

[g] Includes wastes produced by steam generating unit blowdown and ash.

Flue gas desulfurization systems do not consume water in the sense that a large quantity of the water circulating within the system is lost to evaporation or inclusion in a product. The water taken in by the FGD system during operation, or makeup water, is typically about 3 percent of the amount circulating within the system. About half of the makeup water is discharged as wastewater or in scrubber sludge, with the remaining half being lost to evaporation. Consequently, the amount of water needed by an FGD system can be assumed to be approximately double the quantity of wastewater discharged by the system.

Using the conservative assumption that total water consumption by a typical plant would be approximately equal to wastewater production (i.e., no water is being lost to evaporation or inclusion in a product), water consumption by an FGD system at a typical iron and steel plant would constitute approximately 1 to 18 percent of the total water consumption by the plant. For a typical petroleum refinery, water consumption by the FGD system would constitute 16 to 55 percent of the total plant consumption. These figures represent the "extreme" since some types of industry may experience substantial water loss through evaporation (such as sugar refining) or inclusion of water in the product (such as bottling or food processing). In these instances, the proportion of total plant water consumption attributable to the FGD system would be even less than that indicated by the wastewater production figures.

The form of the waste byproducts generated by the use of FGD systems varies from solid wastes, in the form of dry powders (from lime spray drying) or sludges (from lime/limestone or dual alkali wet scrubbing), to liquid wastes (from sodium wet scrubbing). While the form of the wastes generated by the various FGD systems may differ, the composition of these wastes are similar. They consist primarily of calcium sulfite/sulfate salts (in the case of lime spray drying, lime/limestone wet scrubbing, and dual alkali wet scrubbing) or sodium sulfite/sulfate salts (in the case of sodium wet scrubbing). Other constituents may also be present in FGD wastes. However, the source of these constituents is the fly ash resulting from combustion of the fuel. To the extent that disposal of the wastes generated by FGD systems may require treatment or disposal in ponds or landfills with impermeable liners, the same treatment or disposal would also be required for the fly ash.

Thus, while the wastes resulting from standards requiring a percent reduction in SO_2 emissions increase the volume of waste that must be disposed of, the nature of the environmental impacts which might result from disposal of these wastes are similar to those associated with disposal of wastes generated by combustion of fossil fuels in the absence of such standards.

Because coal-fired steam generating units produce greater quantities and a wider range of wastes than do oil-fired steam generating units, coal-fired steam generating units were used for analyzing the potential secondary environmental impacts associated with the use of lime spray drying, dual alkali, and lime/limestone FGD systems. Oil-fired steam generating units, however, were used for analyzing the potential secondary environmental impacts associated with the use of sodium scrubbing. Although the constituents of the wastewater stream from a sodium scrubber-equipped coal-fired steam generating unit can be calculated, as in Table 7-9 below, no actual data are readily available on the characteristics of sodium scrubbing wastewater streams from coal-fired steam generating units.

Lime spray drying FGD systems generate a dry waste byproduct. Because this dry waste byproduct is collected in a particulate matter collection device (fabric filter or electrostatic precipitator), it contains fly ash in addition to the spray drying byproducts.

As mentioned above, wastes produced by lime spray drying systems consist primarily of calcium sulfite, calcium sulfate, and unreacted lime (calcium oxide). Table 7-6 presents typical concentration ranges for the species generally present in lime spray drying FGD waste. This waste product may be more alkaline than those produced by wet scrubbing processes, favoring formation of the more stable sulfate species over the less stable sulfite. In addition, lime spray drying wastes contain trace elements similar to those described above for fly ash. The quantities of trace

TABLE 7-6. CONCENTRATIONS OF MAJOR AND MINOR SPECIES IN LIME SPRAY DRYING WASTE

	Weight Percent Range	
Compound	With Recycle	Without Recycle
SiO_2	18 - 51 (32)[b]	6 - 66 (25)
Al_2O_3	7.7 - 21 (13)	3.4 - 14 (7.7)
TiO_2	0.51 - 1.1 (0.75)	0.17 - 0.75 (0.54)
Fe_2O_3	2.8 - 6.7 (4.5)	1.4 - 7.8 (4.3)
CaO	9.9 - 28 (20.3)	15 - 48 (32)
MgO	1.4 - 3.6 (2.5)	0.51 - 3.0 (1.7)
Na_2O	0.35 - 2.0 (1.36)	0.096 - 2.0 (0.91)
K_2O	0.40 - 1.1 (0.5)	0.26 - 0.99 (0.50)
SO_3	1.4 - 7.0 (4.2)	0.4 - 6.6 (3.4)
SO_2	1.5 - 11.5 (6.1)	1.7 - 14 (6.2)
CO_2	0.44 - 6.6 (2.67)	0.13 - 15 (5.0)
H_2O[a]	0.4 - 6.0 (2.3)	0.4 - 10 (3.6)

[a]Estimate of hydroxide concentrations.

[b]Mean in parentheses.

elements present are a function of the type of fuel fired in the steam generating unit. Table 7-7 presents typical elemental concentrations in lime spray drying waste. These concentrations are less than those present in fly ash. In addition, these wastes have been specifically exempted from characterization as hazardous under the Resource Conservation and Recovery Act (RCRA) by 40 CFR 261.4(b).

The predominant disposal techniques for lime spray drying wastes are ponding and landfilling, as described above for fly ash disposal. The waste products are in the form of a dry, free-flowing powder with physical properties and handling characteristics similar to fly ash. Analyses of waste products from several facilities employing dry scrubbing indicate that the waste products possess enough structural strength to be suitable for landfill applications without additional stabilization or fixation. Another alternative that is currently under investigation is commercial utilization of the dry waste solids in concrete mixtures, in the same manner that fly ash is currently being used.

Again, the solubility of many of the dry scrubbing waste constituents in water could lead to the possibility of leaching of those constituents from the disposal pond or landfill. The structural integrity of the waste prevents any significant leaching from occurring, however, and the possibility can be completely eliminated by the use of an impermeable liner in the pond or landfill.

Dual alkali and lime/limestone wet scrubbing systems generate a waste byproduct that consists primarily of calcium sulfite, bisulfite, and sulfate salts in precipitate form suspended in the scrubbing liquor. The effluent from dual alkali systems also contains sodium sulfite and sulfate in dissolved form. Other substances making up the solid phase of these scrubber wastes include calcium carbonate, unreacted lime or limestone, and fly ash.

In lime/limestone wet scrubbing wastes, the ratio of calcium sulfite to sulfate depends primarily on the extent of oxidation that takes place - the greater the oxidation level, the greater the conversion of sulfite to sulfate. The percentage of sulfate produced is generally greater when

TABLE 7-7. TYPICAL ELEMENTAL COMPOSITION OF LIME SPRAY DRYING WASTE

	Concentration (ppm mass)	
Element	1	2
Antimony	<8	<8
Arsenic	30	28
Barium	350	820
Beryllium	4.3	4.0
Cadmium	<1.0	<1.0
Chromium	52	39
Cobalt	4.9	4.8
Copper	16	33
Iron	20,000	21,000
Lead	<20	<20
Magnesium	15,000	15,000
Molybdenum	16	16
Nickel	215	220
Potassium	4,300	4,600
Selenium	<20	<20
Silver	<0.5	<0.5
Strontium	1,900	1,960
Thallium	<25	<25
Tin	<36	<30
Titanium	3,100	3,200
Vanadium	580	610
Zinc	37	23

firing low sulfur western coal than with higher sulfur eastern coals, and more sulfate is generated from limestone wet scrubbing systems than from lime wet scrubbing systems. The lower pH levels at which limestone wet scrubbers operate and the lower pH of western coals favor oxidation of sulfite to the more stable sulfate.

Most lime/limestone and dual alkali wet scrubbing systems include a dewatering device to concentrate the suspended solids into a sludge prior to treatment and disposal. This leads to the formation of two separate disposal products: a wet sludge containing most of the solid or insoluble waste components, and an aqueous liquor containing the soluble waste components and free ions. Table 7-8 presents typical concentrations of various chemical species in both the liquor and sludge phases. These concentrations may vary widely depending on the type of fuel and FGD system used, and especially on the ash content of the fuel. In almost all cases, well over 90 percent of the total trace element mass is found in the solid phase. This distribution is explained by the very low solubilities of trace metal hydroxides, oxides, and carbonates.

Table 7-8 also lists the maximum concentrations of certain contaminants that are identified under RCRA as toxic and therefore subject to regulation under RCRA (40 CFR 261.24). Under the Extraction Procedure (EP) Toxicity Regulations for identifying toxic wastes, the solid and liquid portions of a waste stream are separated and the solid portion crushed before being dissolved in deionized water at a controlled pH level. The liquid waste and the solid waste solutions are then recombined and analyzed to determine the concentrations of the contaminants listed in 40 CFR 261.24, using standard analytical procedures. If the concentrations of contaminants are revealed by analysis to be in excess of the levels cited in Table 7-8, the treatment, handling and disposal procedures required under RCRA would have to be followed. These RCRA contamination levels have been established at 100 times the contamination levels established for drinking water under the Safe Drinking Water Act. As shown in Table 7-8, the levels of these contaminants found in the sludge and wastewater formed by FGD systems are well below the limitations established by RCRA. Consequently, the disposal of these wastes

TABLE 7-8. TYPICAL LEVELS OF CHEMICAL SPECIES IN WET FGD WASTE SOLIDS AND LIQUORS

Species	FGD Waste Solids (ppm)	FGD Waste Liquor (ppm)	EPA EP Toxicity Criteria (mg/ℓ)[a]
Antimony	-	0.09 - 1.6	-
Arsenic	0.06 - 63	<0.004 - 1.8	5.0
Beryllium	0.05 - 11	<0.0005 - 0.14	-
Cadmium	0.08 - 350	0.004 - 0.1	1.0
Calcium	ND[b]	240 - 45,000[c]	-
Chromium	3 - 250	0.001 - 0.5	5.0
Cobalt	ND	<0.002 - 0.17	-
Copper	1 - 76	0.002 - 0.6	-
Iron	ND	0.02 - 8.1	-
Lead	0.02 - 21	0.001 - 0.55	5.0
Manganese	11 - 120	<0.01 - 9.0	-
Mercury	0.001 - 6	<0.001 - 0.07	0.2
Molybdenum	-	0.9 - 5.3	-
Nickel	6 - 27	0.005 - 1.5	-
Selenium	0.2 - 19	<0.001 - 2.7	1.0
Sodium	ND	36 - 20,000[c]	-
Zinc	10 - 430	0.01 - 27	-
Chloride	-	470 - 43,000[c]	-
Fluoride	-	0.7 - 70	-
Sulfate	-	720 - 30,000[c]	-
TDS	-	2,500 - 95,000[c]	-
pH	-	2.8 - 12.8	-

[a]For FGD systems, ppm concentration values are very nearly equal to mg/ℓ values.

[b]ND - not determined.

[c]Highest values based on single worst-case measurements and may not be representative.

should not deter steam generating unit owners and operators from using FGD systems.

The major constituents of the waste liquor phase are calcium, chloride, magnesium, sodium, sulfate, and sulfite. Chloride is released from the coal as it is fired and enters the flue gas as hydrochloric acid (usually at concentrations less than 5,000 ppm). Sodium concentrations range from less than 100 ppm to over 10,000 ppm for some sodium-based dual alkali systems. The amount of sodium present in the waste liquor depends on the degree of dewatering and the extent of washing of filtered wastes. Calcium sulfite and sulfate are relatively insoluble, so most of these constituents remain in the solid phase of the waste. Calcium concentrations in the waste liquor are generally on the order of 1,000 ppm or less. The sulfate concentrations are limited by the level of calcium present. In conventional direct lime/limestone wet scrubbing systems, sulfate levels are generally under 5,000-8,000 ppm. In dual alkali wet scrubbing systems, or where soluble alkali or alkaline earth compounds are added to lime/limestone wet scrubbing systems to improve performance, sulfate levels may exceed 10,000 ppm. Magnesium sulfite and sulfate are more soluble than the calcium salts, and their concentrations are dependent on the amount of magnesium entering the system. Magnesium concentrations are pH sensitive. If the pH of the waste liquor is raised to 10.5 or greater, magnesium hydroxide will precipitate out and the magnesium levels in the liquor will be negligible.

In general, the sludges from lime/limestone and dual alkali wet scrubbing systems are relatively inert and can be disposed of using conventional methods. The predominant disposal techniques used for these sludges are ponding and landfilling.

Depending on its initial handling properties, the sludge from dual alkali wet scrubbing systems may be disposed of directly, or it may be stabilized with fly ash or fixated with lime prior to disposal. The addition of fly ash reduces the moisture content of the sludge, as well as reducing the permeability of the waste and the pollutant mobility. This assists in mitigating the possibility of pollutant leaching and reduces the solubility of trace metals present in the sludge, thereby reducing the concentrations of these trace metals in the liquor phase. Adding lime to the fly ash/sludge mixture initiates a pozzolanic action which is similar to cement curing, increasing the strength of the mixture and making it more suitable for landfilling.

Lime wet scrubbing systems produce a sludge that is composed primarily of calcium sulfite. Sulfite-rich wastes are more difficult to dewater than are sulfate-rich wastes. Because sulfite sludges retain large amounts of water, they remain very fluid and can only be disposed of by ponding. However, the dewatering properties of this sludge can be improved by the presence of fly ash and unreacted lime. In addition, forced oxidation is being employed at several facilities to oxidize calcium sulfite to calcium sulfate or gypsum. This improves the dewatering and handling properties of the sludge and increases its load-bearing strength, making it more suitable for landfill disposal. The use of an impermeable liner in the waste disposal pond or landfill or waste fixation by mixing it with fly ash or lime will mitigate any potential for leaching of soluble waste components.

Limestone wet scrubbing systems generally operate at lower pH levels than do lime wet scrubbing systems. This enhances the solubility of the sulfite components of the waste and increases its oxidation to sulfate. The higher sulfate concentrations present in limestone wet scrubbing system wastes produce a sludge that is much more easily dewatered than that from lime wet scrubbing systems. Limestone wet scrubbing system waste sludges are amenable to either ponding or landfilling and, depending on local disposal requirements, may be disposed of with or without fixation or stabilization.

Unlike the wet scrubbing systems described above, which convert SO_2 to solid calcium sulfite and calcium sulfate, sodium wet scrubbing systems convert SO_2 to aqueous sodium sulfite and sulfate. The aqueous waste byproduct produced by sodium wet scrubbing systems also contains varying concentrations of other dissolved solids and trace metals. Table 7-9 compares typical constituents of untreated sodium wet scrubbing wastewater streams from oil-fired steam generating units to the EP toxicity contamination levels established under RCRA (40 CFR 261.24). Table 7-9 also

TABLE 7-9. TYPICAL LEVELS OF CHEMICAL SPECIES IN SODIUM SCRUBBING WASTEWATER STREAMS

Species	Oil-Fired System Effluent (mg/ℓ)	Coal-Fired System Effluent[a] (mg/ℓ)	RCRA EP Toxicity Criteria (mg/ℓ)
Arsenic	0.01-0.60	0.12-0.92	5.0
Barium	0.01-1.0	0.41-3.22	100.0
Beryllium	-	0.01-0.077	-
Boron	-	0.40-3.14	-
Cadmium	0.005-0.20	0.008-0.061	1.0
Chromium	0.06-0.36	0.26-1.99	5.0
Copper	0.08-0.30	0.11-4.84	-
Iron	4.2-14	38.9-301.3	-
Lead	0.01-0.62	0.089-0.69	5.0
Manganese	0.22-0.40	0.18-1.38	-
Mercury	0.002-0.006	0.009-0.005	0.2
Nickel	0.05-37.0	0.28-2.22	-
Phosphorus	-	0.48-3.76	-
Selenium	0.19-0.54	0.03-0.23	1.0
Silver	0.05-0.70	-	5.0
Zinc	0.21-12	0.19-1.53	-
Sulfate (SO_4^{-2})	8,500-67,500	-	
Chloride (Cl^-)	130-34,000	-	
Total Sulfite (SO_3^{-2} and HSO_3^-)	7,200-130,000	-	
Sodium (Na+)	11,500-67,500	-	
Total Dissolved Solids	27,300-300,000	-	
Chemical Oxygen Demand	1,400-26,000	-	
Total Suspended Solids	670-3,300	-	
pH	5.0-8.1	7-7.5	

[a]Based on calculations using 1 percent ash capture assumption and EPA emission factors. Range includes values for high and low sulfur coal, and pulverized coal and spreader stoker steam generating unit.

compares the calculated characteristics of sodium scrubbing wastewater streams from coal-fired stream generating units to the EP toxicity levels. No actual data are readily available on the characteristics of sodium wet scrubbing wastewater streams from coal-fired steam generating units.

This scrubber wastewater is generally diluted prior to disposal by mixing with other plant wastewater streams. The combined wastewater stream is then oxidized and treated for suspended solids. Alternatively, because the sodium wet scrubbing wastewater stream exerts a high oxygen demand, it is sometimes oxidized separately before mixing with other plant wastes. These steps reduce the solids content of the scrubber waste stream to negligible amounts when compared to total plant wastes.

As shown in Table 7-9, the aqueous component of the sodium wet scrubbing wastewater stream may also contain small quantities of trace metals and minerals. The specific concentrations of these elements are a function of the type of fuel fired in the steam generating unit, the amount of ash present in the wastewater stream, and the solubility of the trace metal compounds. Many of the trace elements can precipitate out as hydroxides during treatment of the wastewater to remove suspended solids. Therefore, the concentrations shown in Table 7-9 represent conservatively high estimates. After dilution and treatment, the trace elements in the plant effluent attributable to the sodium wet scrubbing wastewater stream would be well below the RCRA toxicity limits shown in Table 7-9.

The trace metal composition of the sodium wet scrubber wastewater from coal-fired steam generating units will depend primarily on the type of coal fired and its ash content. The fly ash resulting from coal combustion, as previously shown in Table 7-2, has greater concentrations of trace elements than those resulting from oil combustion (shown in Table 7-9). However, unlike oil-fired steam generating units, coal-fired steam generating units will be equipped with fabric filters upstream of the FGD system. The fabric filter will remove 98 to 99 percent of the fly ash (and therefore the trace elements) from the wastewater stream, reducing the concentration of most of these trace elements to 1 to 2 percent of their potential concentration. In addition, due to the low solubility of many trace metal hydroxides, oxides, and carbonates, a large percentage of the trace elements remaining in the wastewater stream after fabric filter collection will precipitate out. Therefore, the trace metal concentrations for coal-fired steam generating units would be expected to fall within the range given in Table 7-9.

Sodium wet scrubbing wastewater may in many cases be discharged directly to a receiving water body or to a publicly owned treatment works (POTW). In arid areas where net evaporation exceeds net precipitation, the wastewater stream is usually discharged to an evaporation pond. Other possible disposal methods include deep well injection and injection with the steam used in thermally enhanced oil recovery operations, two techniques that are used to some extent in California and other western states. California regulations for evaporation ponds and deep well injection do not consider sodium wet scrubbing wastes to be hazardous.

There is a possibility that aqueous sulfur species discharged to a receiving water body or sewer may be re-emitted as SO_2 in aerobic receiving waters or hydrogen sulfide (H_2S) in anaerobic environments (sewers). This may be prevented in aerobic environments by raising the pH of the wastewater during oxidation and by providing enough oxygen transfer capabilities to ensure high conversion of sulfite to the more stable sulfate. Oxygen depletion of wastewater in anaerobic environments, which promotes H_2S formation, can be prevented by injecting air at various points along the sewer main and by preventing the sewer flow from becoming stagnant. Oxidation of the sulfur species prior to disposal and maintenance of a high pH will also help prevent formation of H_2S.

8.0 CONSIDERATION OF NATIONAL IMPACTS

The potential national impacts associated with various new source performance standards (NSPS) were analyzed. The analysis examined the incremental national environmental and cost impacts in the fifth year following proposal of standards compared to a regulatory baseline. The regulatory baseline represents the level of control required by existing State implementation plans and the existing NSPS (40 CFR Part 60, Subpart D) applicable to steam generating units of more than 73 MW (250 million Btu/hour) heat input. National impacts were examined for fossil fuel-fired steam generating units (i.e., coal, oil or natural gas) and for mixed fuel-fired steam generating units (i.e., mixtures of fossil fuels or fossil and nonfossil fuels).

8.1 FOSSIL FUEL-FIRED STEAM GENERATING UNITS

National impacts on new industrial fossil fuel-fired steam generating units were analyzed through the use of a computer model called the Industrial Fuel Choice Analysis Model (IFCAM). IFCAM is an energy demand model developed to evaluate fuel choice decisions among coal, oil, and natural gas by the industrial sector. The population of new industrial steam generating units in 1990 is projected in IFCAM and the total cost of each alternative fossil fuel, including the costs imposed by environmental regulations, is compared on an after-tax discounted cash flow basis for each steam generating unit over a 15-year investment period. The lowest cost combination of fossil fuel and emission control system is determined for each steam generating unit. These results are then aggregated to yield national projections in 1990 of fossil fuel consumption by fuel type, capital and annualized costs, sulfur dioxide emissions, and solid and liquid wastes.

The magnitude of the economic, environmental, and energy impacts associated with alternative control levels for new industrial steam generating units in IFCAM is a function of two major variables. These are the number of new fossil fuel-fired steam generating units projected and the type of fuel selected for each of these steam generating units.

The number of new industrial steam generating units projected in 1990 is a function of the projected growth in industrial fossil fuel energy demand. Based on the "Annual Energy Outlook 1983," issued by the Department of Energy, fossil fuel energy demand by new industrial steam generating units installed between 1985 and 1990 with a heat input capacity of more than 29 MW (100 million Btu/hour) is projected by IFCAM to be about 525 million GJ/year (498 trillion Btu/year). This compares to a 1982 fossil fuel energy consumption of about 18 billion GJ (17.3 quadrillion Btu) by the industrial sector, of which about 7.4 billion GJ (7.0 quadrillion Btu) were consumed by existing industrial steam generating units. Based on this projected fossil fuel energy demand, IFCAM projects construction of about 600 new fossil fuel-fired industrial steam generating units with a heat input capacity greater than 29 MW (100 million Btu/hour) between 1985 and 1990.

The type of fossil fuel selected for each new steam generating unit in IFCAM is a function of the projected prices for coal, oil, and natural gas. Several economic models were used to develop these projections. Coal prices were projected with the Coal and Electric Utilities Model (CEUM), a proprietary model developed by ICF, Incorporated. The model can be used to translate assumptions about growth in electric utility energy demand and global energy and economic conditions into projections of future coal prices.

In generating coal price forecasts, several assumptions were made concerning energy demand and economic conditions. Annual growth in GNP was assumed to be 3 percent between 1985 and 1990 and 2.5 percent between 1991 and 2000. World oil prices were assumed to increase from $32 per barrel in 1985 to $46 per barrel in 2000 (mid-1982 dollars). In addition, the Natural Gas Policy Act was assumed to be implemented in its current form with natural gas deregulation occuring in 1985. The growth in electricity demand was assumed to be 2.7 percent per year between 1985 and 2000.

Table 8-1 summarizes the coal prices projected by CEUM. While coal prices are projected to increase modestly during the timeframe of the forecast, the prices presented in Table 8-1 have been levelized and expressed in terms of 1982 dollars. Levelized prices are calculated by discounting prices in each year over the 15-year investment period to a present value, and multiplying this present value by a capital recovery factor to obtain a single price that represents the entire 15-year price forecast.

These coal prices are higher than those experienced by electric utilities. Industrial steam generating units do not generate sufficient demand to command either long-term contracts or bulk transportation rates. Consequently, industrial steam generating units generally purchase coal on the spot market at higher prices than utility steam generating units. Additionally, these projected coal prices exhibit "sulfur premiums" ranging from a negligible amount to about $0.72/GJ ($0.76/million Btu) for purchase of low sulfur coal over purchase of high sulfur coal.

In addition to coal prices, prices were forecast for residual fuel oil and natural gas. No prices were forecast for distillate fuel oil. Prices for this fuel are higher than for residual fuel oil and natural gas. Hence, distillate oil is not expected to be widely used as a fuel in new industrial-commercial-institutional steam generating units.

Residual fuel oil prices were projected with the World Oil (WOIL) forecasting model developed by EEA, Incorporated for the Department of Energy. The model generates projections of free world energy production, demand, and prices for five world regions. Energy consumption is projected by fuel type and sector from assumptions about economic growth, growth in energy demand, and OPEC oil production capacity. The model assumed a free-world economic growth rate of 3 percent per year between 1983 and 2000 in real terms. Growth in energy demand was assumed to be about 1.5 percent per year. This energy demand growth is less than the economic growth rate because of increases in energy conversion efficiency. Non-OPEC oil production was assumed to fall by about 3 percent per year between 1990 and 1995 with the shortfall in production met by rapidly increasing OPEC production. These assumptions lead to projections of a firm oil market

TABLE 8-1. LEVELIZED INDUSTRIAL FUEL PRICES: HIGH OIL PENETRATION ENERGY SCENARIO[a]
(1982 $/Million Btu)

Fuel Type	New England	New York/ New Jersey	Middle Atlantic	South Atlantic	Midwest	Southwest	Central	North Central	West	Northwest
Natural gas	5.82	5.78	5.73	6.02	5.88	5.41	5.45	4.91	5.44	5.57
Residual fuel oil										
(lb SO_2/million Btu)										
3.0	4.80	4.79	4.79	4.77	4.94	4.79	4.91	4.60	4.39	4.35
1.6	5.12	5.11	5.11	5.09	5.25	5.11	5.22	4.93	4.71	4.67
0.8	5.50	5.49	4.49	5.46	5.63	5.49	5.60	5.29	5.11	5.07
0.3	5.87	5.85	5.85	5.83	6.01	5.85	5.98	5.67	5.45	5.41
Bituminous Coal										
(lb SO_2/million Btu)										
<1.2	3.76	3.52	3.14	3.19	3.32	3.34	3.14	1.99	2.79	3.18
1.2-1.7	3.71	3.45	2.94	2.98	3.18	3.21	3.08	1.86	2.82	2.97
1.7-2.5	3.65	3.29	2.85	2.96	3.08	3.20	3.04	1.87	2.77	2.84
2.5-3.4	3.46	3.13	2.75	2.88	2.93	3.19	2.92	-	-	-
3.4-5.0	3.16	2.82	2.42	2.79	2.67	3.09	2.62	-	-	-
>5.00	3.26	2.85	2.39	2.62	2.50	2.96	2.47	-	-	-
Subbituminous coal										
(lb SO_2/million Btu)										
<1.2	-	-	-	-	3.38	3.49	2.74	1.40	2.84	2.66
1.2-1.7	-	-	-	-	3.34	3.39	2.69	1.39	2.74	2.60
1.7-2.5	-	-	-	-	3.30	3.33	2.72	1.29	2.65	2.09

[a]Ten percent discount rate. Fifteen-year period beginning in 1987.

characterized by crude oil prices increasing at an average real rate of 2.8 percent annually.

The residual oil prices are shown in Table 8-1. As was done for coal prices, these prices are presented as levelized prices. Additionally, these projected residual oil prices exhibit "sulfur premiums" of about $1/GJ ($1.05/million Btu) for purchase of low sulfur residual oil over purchase of high sulfur oil.

Natural gas prices were projected with the Hydrocarbon Supply Model. This model was developed by EEA, Incorporated for the Strategic Analysis and Energy Forecasting Division of the Gas Research Institute. The model translates assumptions about economic growth, growth in energy demand, world oil prices, regulation of natural gas prices, and natural gas imports into projections of future natural gas prices. The model assumed the projected world oil prices discussed above. Energy demand and economic growth were assumed to be the same as those discussed above in forecasting residual oil prices. In addition, the model assumed that the Natural Gas Policy Act will be implemented in its current form, that contract pricing issues will be resolved to allow the market to determine prices, that Canadian and Mexican imports will track the lower-48 states market prices after decontrol, that two trillion cubic feet of Canadian gas will be imported by 1987, and that the gas industry will establish an effective dual pricing system. Natural gas prices are also shown in Table 8-1. As was done for coal and residual oil prices, the natural gas prices are presented as levelized prices.

This energy scenario reflects a "best guess" of future coal, oil, and natural gas prices. Oil prices are relatively low and natural gas prices are generally at or above the price of low sulfur residual oil. As shown in Table 8-2, under this energy price scenario residual oil and natural gas compete for the industrial steam generating unit energy market, with residual oil achieving a slightly larger share. Coal does not effectively compete in this market due to the relatively low oil and natural gas prices. Thus, this energy pricing scenario is referred to as the high oil penetration scenario.

TABLE 8-2. NATIONAL IMPACTS[a]

Fossil Fuel-Fired Steam Generating Units

Regulatory Baseline (Base Case)

1990

	Energy Pricing Scenario	
	High Oil Penetration	High Coal Penetration
SO_2 Emissions, thousand tons/year	279	326
Annualized Costs, million $/year[b]	3,350	3,725
Fuel Use, trillion Btu/year		
Coal	23	284
Oil	323	7
Natural Gas	152	207

[a]New fossil fuel-fired steam generating units with a heat input capacity of more than 29 MW (100 million Btu/hour) installed between 1985 and 1990.

[b]1982 dollars.

In response to concerns that this energy pricing scenario might underestimate coal penetration in the new industrial steam generating unit energy market, an alternative energy scenario was developed to yield higher coal penetration. In this energy scenario, coal prices were assumed to remain the same as those discussed above for the high oil penetration energy scenario. Alternative residual oil prices were developed according to the method discussed above except that higher world oil prices were used. The world oil prices used were those developed by the Department of Energy and used in The National Energy Policy Plan, 1983 (NEPP-IV) projections. NEPP-IV contains three world oil price projections reflecting high, middle, and low price levels. The middle world oil price level contained in NEPP-IV was used in the high coal penetration energy scenario. These world oil prices are higher than the world oil prices used in the high oil penetration energy scenario and range from about 3.5 percent higher in 1985 to about 45 percent higher in 1995. All other assumptions used to forecast residual oil prices are the same in this energy scenario as in the high oil penetration energy scenario.

In a similar manner, the NEPP-IV world oil prices were used to project alternative natural gas prices. All other assumptions used to forecast natural gas prices are the same in this energy scenario as in the high oil penetration energy scenario.

The oil and natural gas prices used for this energy scenario are presented in Table 8-3. As shown in Table 8-2, in this scenario coal and natural gas compete for the steam generating unit energy market with coal capturing a slightly larger share than natural gas. Oil does not effectively compete in this market due to the relatively low coal and natural gas prices. This energy scenario, therefore, is referred to as the high coal penetration scenario.

8.1.1 Selection of Regulatory Alternatives

In order to assess the "sensitivity" of IFCAM projections, a number of alternative control levels based on the use of low sulfur fuels to reduce

TABLE 8-3. LEVELIZED INDUSTRIAL FUEL PRICES: HIGH COAL PENETRATION ENERGY SCENARIO[a]
(1982 $/Million Btu)

Fuel Type	New England	New York/ New Jersey	Middle Atlantic	South Atlantic	Midwest	Southwest	Central	North Central	West	Northwest
Natural gas	6.39	6.38	6.37	6.52	6.48	6.01	5.87	5.26	5.82	5.79
Residual fuel oil										
(3.0 lb SO_2/million Btu)	6.00	5.99	5.99	5.97	6.12	5.99	6.09	5.82	5.58	5.55
(1.6 lb SO_2/million Btu)	6.42	6.41	6.41	6.39	6.54	6.41	6.51	6.23	6.00	5.96
(0.8 lb SO_2/million Btu)	6.90	6.89	6.89	6.87	7.02	6.89	6.99	6.71	6.52	6.48
(0.3 lb SO_2/million Btu)	7.38	7.37	7.37	7.35	7.50	7.37	7.47	7.19	6.96	6.62

[a]Ten percent discount rate. Fifteen-year period beginning in 1987.

SO_2 emissions, or the use of flue gas desulfurization (FGD) systems to achieve a percent reduction in SO_2 emissions, were examined in a preliminary analysis and compared to the regulatory baseline. As stated previously, the regulatory baseline is defined by existing State implementation plans and the existing NSPS (40 CFR, Part 60, Subpart D) for large steam generating units of more than 73 MW (250 million Btu/hr) heat input capacity.

As mentioned earlier, under the regulatory baseline, oil and natural gas are responsible for about 96 percent of fuel use under the high oil penetration scenario. As a result, IFCAM projects minimal impacts associated with alternative control levels limiting SO_2 emissions from coal combustion under this energy scenario. In the high coal penetration scenario, coal and natural gas are responsible for about 99 percent of fuel use under the regulatory baseline. IFCAM, therefore, projects minimal impacts associated with alternative control levels limiting SO_2 emissions from oil combustion under this energy scenaro. Thus, in the high oil penetration scenario, impacts are determined primarily by the limits placed on SO_2 emissions from oil-fired steam generating units, and in the high coal penetration scenario, impacts are determined by the limits placed on SO_2 emissions from coal-fired steam generating units.

As discussed earlier in "Consideration of Demonstrated Emission Control Technology Costs," requirements to achieve percent reductions of much less than 70 percent in SO_2 emissions resulting from combustion of oil would generally not reduce emissions to levels below that achieved by the combustion of low sulfur oil. Similarly, requirements to achieve percent reductions of much less than 50 percent in SO_2 emissions resulting from combustion of coal would generally not reduce emissions to levels below those achieved by the combustion of low sulfur coal. Consequently, the alternative control levels examined for limiting SO_2 emissions from oil combustion included alternatives based on the use of low sulfur oils and alternatives requiring a reduction in SO_2 emissions of 70 percent or more. The alternative control levels examined for limiting SO_2 emissions from coal combustion included alternatives based on the use of low sulfur coal and alternatives requiring a reduction in SO_2 emissions of 50 percent or more.

The alternative control levels examined in the preliminary analysis are summarized in Table 8-4. Alternative control levels I and II are based on the use of low sulfur fuel to reduce emissions to 688 and 344 ng SO_2/J (1.6 and 0.8 lb SO_2/million Btu) heat input from oil combustion and to 731 and 516 ng SO_2/J (1.7 and 1.2 lb SO_2/million Btu) heat input from coal combustion. Alternative control level III is based on the use of FGD systems to achieve a 50 percent reduction in SO_2 emissions from coal combustion and reduce emissions to 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input from oil combustion. As mentioned above, a requirement to achieve a percent reduction in SO_2 emissions from oil combustion of less than 70 percent would generally not reduce emissions to levels below that achieved through the combustion of low sulfur oil. Thus, an alternative control level of 50 percent reduction in SO_2 emissions was not examined for oil combustion in the analysis of national impacts.

Alternative control level IV is based on the use of FGD systems to achieve a 90 percent reduction in SO_2 emissions, with an exemption from this requirement if SO_2 emissions are 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input or less from coal combustion or 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input or less from oil combustion.

Alternative control level V is based on the use of FGD systems to achieve a 90 percent reduction in SO_2 emissions and reduce emissions from coal combustion to less than 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input and from oil combustion to less than 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input. If emissions can be reduced to less than 258 ng SO_2/J (0.6 lb SO_2/million Btu) heat input for coal or 129 ng SO_2/J (0.3 lb SO_2/million Btu) heat input for oil, alternative control level V would only require a minimum percent reduction of 70 percent. This alternative control level represents the existing NSPS under Subpart Da for utility steam generating units.

Finally, alternative control level VI, the most stringent alternative, is based on the use of FGD systems to achieve a 90 percent reduction in SO_2 emissions from both oil and coal combustion and reduce emissions from coal combustion to less than 258 ng/J (0.6 lb SO_2/million Btu) heat input and

TABLE 8-4. ALTERNATIVE CONTROL LEVELS

Fossil Fuel-Fired Steam Generating Units

Alternative	Oil Combustion	Coal Combustion
Low Sulfur Fuel		
I	1.6 lb SO_2/million Btu	1.7 lb SO_2/million Btu
II	0.8 lb SO_2/million Btu	1.2 lb SO_2/million Btu
Percent Reduction		
III	-[a]	50% and 0.9 lb SO_2/million Btu
IV	90% or 0.3 lb SO_2/million Btu	90% or 0.6 lb SO_2/million Btu
V	90% and 0.8 lb SO_2/million Btu or 70% and 0.3 lb SO_2/million Btu	90% and 1.2 lb SO_2/million Btu or 70% and 0.6 lb SO_2/million Btu
VI	90% and 0.3 lb SO_2/million Btu	90% and 0.6 lb SO_2/million Btu

[a] SO_2 emissions from oil combustion limited to 0.8 lb SO_2/million Btu.

from oil combustion to less than 129 ng/J (0.3 lb SO_2/million Btu) heat input.

The results of the preliminary analyses under the high oil penetration and high coal penetration energy scenarios are summarized in Table 8-5. Before discussing the results of this preliminary analysis, there is one point that should be mentioned. As shown in Table 8-5, the cost impacts associated with alternative control levels limiting SO_2 emissions from oil combustion under the high oil penetration scenario are greater than the cost impacts associated with alternative control levels limiting SO_2 emissions from coal combustion under the high coal penetration scenario. This is explained by the type and amount of fuel switching that occurs under each energy scenario in response to limits on SO_2 emissions, as well as the greater number of steam generating units affected under the high oil penetration scenario than under the high coal penetration scenario.

In response to progressively more stringent standards, under the high coal penetration scenario, coal-fired units switch to natural gas, and under the high oil penetration scenario, oil-fired units switch to natural gas. As discussed below and illustrated in Table 6-19, because IFCAM summarizes annualized cost impacts on a before-tax basis, but makes fuel selection decisions on an after-tax basis, fuel switching from coal to natural gas can result in negative before-tax levelized cost impacts (i.e., decreased costs). This tends to mitigate the apparent cost impacts under the high coal penetration scenario. Under the high oil penetration scenario, however, fuel switching from oil to natural gas always results in positive cost impacts (i.e., increased costs). Thus, fuel switching does not mitigate the apparent cost impacts under the high oil penetration scenario.

As also mentioned, a larger number of steam generating units are impacted under the high oil penetration scenario than under the high coal penetration scenario. Consequently, more FGD systems are installed under the high oil penetration scenario than under the high coal penetration scenario. This also contributes to the higher cost impacts under the high oil penetration scenario than under the high coal penetration scenario.

TABLE 8-5. PRELIMINARY ANALYSIS OF NATIONAL IMPACTS

Fossil Fuel-Fired Steam Generating Units[a]

Alternative Control Level	Base Case	I	II	III	IV	V	VI
High Oil Penetration Scenario							
SO_2 Emissions, thousand ton/yr	279	205	106	102	39	47	16
Annualized Costs, $million/yr[b]	3,349	3,357	3,406	3,408	3,476	3,474	3,482
Fuel Use, trillion Btu/yr							
o Coal	23	17	17	9	26	26	26
o Oil	323	328	257	257	205	205	178
o Gas	152	153	224	232	267	267	294
Cost Effectiveness, $/ton[b]							
o Average	-	110	330	330	530	540	510
o Incremental	-	-	490	500	1,080	-	260
High Coal Penetration Scenario							
SO_2 Emissions, thousand ton/yr	326	148	114	46	34	30	16
Annualized Costs, $million/yr[b]	3,725	3,735	3,743	3,754	3,757	3,758	3,757
Fuel Use, trillion Btu/yr							
o Coal	284	261	248	153	153	153	147
o Oil	7	0	0	0	0	0	0
o Gas	207	237	250	345	345	345	351
Cost Effectiveness, $/ton[b]							
o Average	-	60	80	100	110	110	100
o Incremental	-	-	240	160	250	250	0

[a]National impacts in 1990 of new fossil fuel-fired steam generating units installed between 1985 and 1990 of more than 29 MW (100 million Btu/hour) heat input capacity.

[b]1982 dollars.

The results obtained under the high oil penetration scenario indicate that alternative control levels I and II, based on low sulfur oil and limiting SO_2 emissions from oil combustion to 688 and 344 ng SO_2/J (1.6 and 0.8 lb SO_2/million Btu) heat input, respectively, would achieve reductions in SO_2 emissions of 68,000 to 159,000 Mg/year (75,000 to 175,000 tons/year), with increases in annualized costs of $10 to $60 million/year. The average cost effectiveness of emission control under each of these alternatives is $121 to $364/Mg ($110 to $330/ton) of SO_2 removed. The control of SO_2 emissions under these alternatives also results in a shift of up to 74 million GJ/year (70 trillion Btu/year) from oil combustion to natural gas combustion.

Table 8-5 also shows that the impacts under the high oil penetration scenario associated with alternative control level III, which requires a percent reduction in emissions of 50 percent and a reduction in emissions to 387 ng SO_2/J (0.9 lb SO_2/million Btu) heat input from coal combustion and to 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input from oil combustion, are essentially the same as the impacts associated with alternative control level II which limits SO_2 emissions from coal combustion to 516 ng SO_2/J/ (1.2 lb SO_2/million Btu) and from oil combustion to 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input. This result shows, as mentioned above, that impacts under the high oil penetration energy scenario are determined primarily by the SO_2 emission limits placed on oil combustion.

Alternative control levels IV, V, and VI require a percent reduction in SO_2 emissions from oil combustion to achieve emission reductions of 200,000 to 236,000 Mg/year (220,000 to 260,000 tons/year), at increases in annualized costs of $120 to $130 million/year over the regulatory baseline. The average cost effectiveness of alternative control levels requiring a percent reduction in SO_2 emissions ranges from $560 to $600/Mg ($510 to $540/ton) of SO_2 removed.

The incremental cost effectiveness of alternative control level IV over alternative control level III (i.e., percent reduction over low sulfur fuel) is approximately $1,190/Mg ($1,080/ton) of SO_2 removed. Note, however, that the incremental cost effectiveness decreases, rather than increases, in progressing from alternative IV to alternative VI. Alternative control level VI, therefore, is more cost effective in reducing SO_2 emissions than either alternatives IV or V. This is consistent with the analysis discussed in "Consideration of Demonstrated Emission Control Technology Costs," which also indicates that a percent reduction requirement of 90 percent is more cost effective than other percent reduction requirements.

The most cost effective alternative requiring a percent reduction in emissions should be used to calculate the incremental cost effectiveness of alternative control levels requiring a percent reduction in SO_2 emissions over alternative control levels based on the use of low sulfur fuels. Consequently, alternative control level VI, rather than alternative control level IV, should be used in this calculation. Thus, the incremental cost effectiveness of alternatives which require a percent reduction in SO_2 emissions over alternatives based on the use of low sulfur fuels should be viewed as $945/Mg ($860/ton) of SO_2 removed.

Finally, there is a shift of about 116 to 153 million GJ/year (110 to 145 trillion Btu/year) from oil combustion to coal or natural gas combustion under alternative control levels IV, V, and VI.

The results obtained under the high coal penetration scenario indicate that alternative control levels limiting SO_2 emissions from coal combustion to 731 and 516 ng SO_2/J (1.7 and 1.2 lb SO_2/million Btu) heat input would achieve a reduction in SO_2 emissions of 163,000 to 191,000 Mg/year (180,000 to 210,000 tons/year) at increases in annualized costs of $10 to $20 million/year. The average cost effectiveness of emission control is $66 to $88/Mg ($60 to $80/ton) of SO_2 removed. The control of SO_2 emissions under these alternatives also result in a shift of up to 42 million GJ/year (40 trillion Btu/year) from coal combustion to natural gas combustion.

Alternative control levels III through VI require a percent reduction in SO_2 emission from coal combustion. As a result, these alternatives would achieve reductions in SO_2 emissions of about 281,000 Mg/year (310,000 tons/year), at increases in annualized costs of about $30 million/year. The average cost effectiveness of alternative control levels requiring a percent reduction in emissions is about $110/Mg ($100/ton) of SO_2 removed. The incremental cost effectiveness over alternatives based on the use of low sulfur coal is about \$276/Mg (\$250/ton) of SO_2 removed. Fuel switching from coal to natural gas combustion, however, increases to 137 to 148 million GJ/year (130 to 140 trillion Btu/year).

The results of this preliminary analysis are presented graphically in Figure 8-1. Several conclusions may be drawn from these results. First, there is little difference in annualized costs among alternative control levels requiring a percent reduction in SO_2 emissions. National cost impacts projected by IFCAM are relatively insensitive to variations in the level of the percent reduction requirement. Thus, little insight is gained from analysis of a number of alternatives requiring various percent reductions in SO_2 emissions. Consequently, the regulatory analysis discussed below used a single percent reduction alternative control level of 90 percent to represent the range of percent reduction requirements that could be included in the NSPS. As mentioned above and discussed in "Consideration of Demonstrated Emission Control Technology Costs," a percent reduction requirement of 90 percent is the most cost effective percent reduction alternative.

Second, under the high oil penetration scenario, there is a significant difference in annualized costs among alternative control levels based on the use of various low sulfur fuels. IFCAM, therefore, is sensitive under this energy scenario to different alternative control levels limiting SO_2 emissions from oil combustion based on the use of various low sulfur fuels. Consequently, the regulatory analysis examined two alternative control levels based on the use of low sulfur fuel under the high oil penetration energy scenario. One alternative limits SO_2 emissions from oil combustion to 688 ng SO_2/J (1.6 lb SO_2/million Btu) heat input and from coal combustion to 731 ng SO_2/J (1.7 lb SO_2/million Btu) heat input. Another alternative limits SO_2 emissions from oil combustion to 344 ng SO_2/J (0.8 lb SO_2/million Btu) heat input and from coal combustion to 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input.

Third, under the high coal penetration scenario, there is little difference in annualized costs among alternative control levels based on the

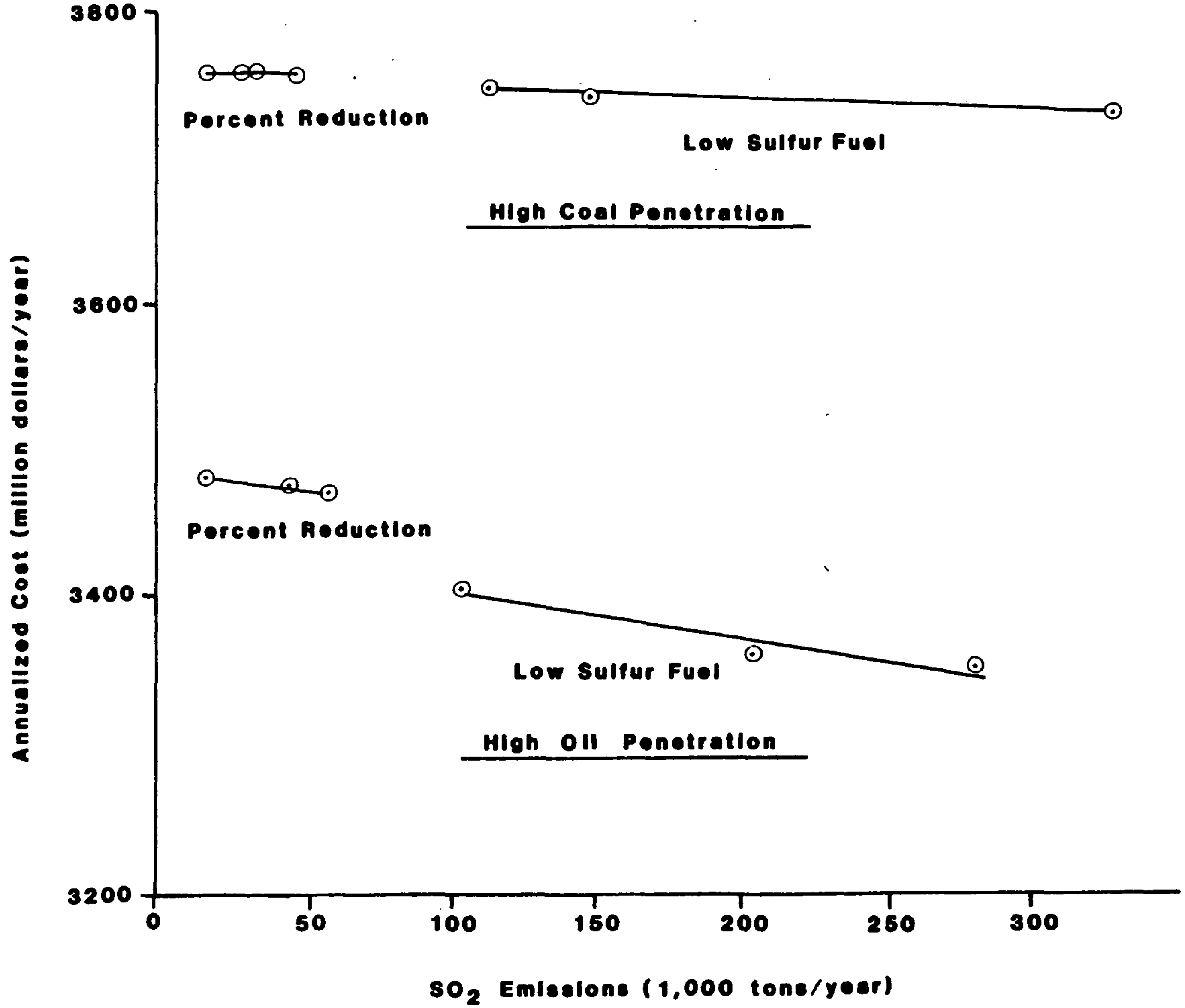

Figure 8-1. Annualized Costs and SO_2 Emission Reductions for Regulatory Alternatives

use of various low sulfur fuels. As a result, the national cost impacts projected by IFCAM are relatively insensitive to alternatives based on the use of various low sulfur fuels under this energy scenario. Consequently, the regulatory analysis examined only one alternative control level based on the use of low sulfur fuel under the high coal penetration scenario: reducing SO_2 emissions from oil combustion to 344 ng SO_2/J (0.8 lb SO_2/million Btu) and from coal combustion to 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input.

As a result, IFCAM was used to examine the potential impacts associated with six regulatory alternatives limiting SO_2 emissions from steam generating units firing fossil fuels under the high oil penetration energy scenario and five regulatory alternatives under the high coal penetration energy scenario. These regulatory alternatives are summarized in Table 8-6.

As shown in Table 8-6, the population of steam generating units was divided into four size categories. As mentioned above, under the high oil penetration scenario, the impacts of two alternative control levels based on the use of low sulfur fuels were examined. Under the high coal penetration scenario, the impacts of only one alternative control level based on the use of low sulfur fuels were examined. The regulatory alternatives under both energy scenarios result from first applying the alternative control level(s) based on the use of low sulfur fuels to all steam generating units, and then applying the alternative control level requiring a percent reduction in SO_2 emissions, first to large steam generating units, and then to smaller and smaller steam generating units. This leads to a succession of regulatory alternatives, each one more stringent than the previous alternative.

8.1.2 Analysis of Regulatory Alternatives

The national impacts projected by IFCAM for each of the regulatory alternatives under the high oil penetration energy scenario are summarized in Table 8-7. An anomaly appears to arise under the high oil penetration energy scenario in progressing from alternative 2 to alternative 3 and then to alternatives 4 through 6 in the incremental cost effectiveness of

TABLE 8-6. REGULATORY ALTERNATIVES

Fossil Fuel-Fired Steam Generating Units

Regulatory Alternative[a]	Steam Generating Unit Size (million Btu/hr)			
	100-150	150-200	200-250	>250
High Oil Penetration				
Baseline	Base	Base	Base	Base
Alternative 1	1.6/1.7	1.6/1.7	1.6/1.7	0.8/1.2
Alternative 2	0.8/1.2	0.8/1.2	0.8/1.2	0.8/1.2
Alternative 3	0.8/1.2	0.8/1.2	0.8/1.2	90% Reduction
Alternative 4	0.8/1.2	0.8/1.2	90% Reduction	90% Reduction
Alternative 5	0.8/1.2	90% Reduction	90% Reduction	90% Reduction
Alternative 6	90% Reduction	90% Reduction	90% Reduction	90% Reduction
High Coal Penetration				
Baseline	Base	Base	Base	Base
Alternative 1	0.8/1.2	0.8/1.2	0.8/1.2	0.8/1.2
Alternative 2	0.8/1.2	0.8/1.2	0.8/1.2	90% Reduction
Alternative 3	0.8/1.2	0.8/1.2	90% Reduction	90% Reduction
Alternative 4	0.8/1.2	90% Reduction	90% Reduction	90% Reduction
Alternative 5	90% Reduction	90% Reduction	90% Reduction	90% Reduction

[a]Control levels shown for each regulatory alternative are SO_2 emission limits in lb SO_2/million Btu for oil and coal, respectively, or a required percent reduction in SO_2 emissions.

TABLE 8-7. NATIONAL IMPACTS OF REGULATORY ALTERNATIVES

Fossil Fuel-Fired Steam Generating Units

Regulatory Alternative	Annual Emissions (1,000 tons/yr)	Annualized Costs ($/yr million)	Cost Effectiveness ($/ton)		Fuel Use (trillion Btu/yr)			Quantity of Fuel Scrubbed (trillion Btu)		Liquid Waste (million ft^3/yr)	Solid Waste (1000 tons/yr)
			Average	Incremental	Coal	Oil	Gas	Coal	Oil		
High Oil Penetration											
Baseline	279	3,349	-	-	23	323	152	4	23	228	110
Alternative 1	205	3,357	108	-	17	329	153	4	23	225	75
Alternative 2	106	3,406	330	500	17	257	224	4	64	240	80
Alternative 3	72	3,445	460	1,150	30	217	251	26	96	284	150
Alternative 4	61	3,450	460	450	30	215	253	26	117	301	150
Alternative 5	40	3,464	480	670	29	204	265	26	151	328	140
Alternative 6	16	3,482	510	750	26	178	294	26	178	352	130
High Coal Penetration											
Baseline	326	3,725	-	-	284	7	207	17	0	223	1,350
Alternative 1	114	3,743	80	-	248	0	250	23	0	229	1,150
Alternative 2	66	3,771	180	580	223	0	275	101	0	330	1,050
Alternative 3	49	3,768	160	-180	197	0	301	118	0	351	950
Alternative 4	26	3,754	100	-610	159	0	339	141	0	381	820
Alternative 5	16	3,757	100	300	147	0	351	147	0	396	770

emission control. The incremental cost effectiveness increases from \$550/Mg (\$500/ton) to \$1,270/Mg (\$1,150/ton), decreases to \$495/Mg (\$450/ton) and then increases steadily to \$825/Mg (\$750/ton) of SO_2 removed.

This anomaly is explained by the difference in the amount of fuel switching that occurs among steam generating units above and below 73 MW (250 million Btu/hour) heat input capacity in response to requirements to achieve a percent reduction in SO_2 emissions. For steam generating units above 73 MW (250 million Btu/hour) heat input capacity, there is relatively little fuel switching from oil or coal to natural gas. Below 73 MW (250 million Btu/hour) heat input capacity, there is a substantial amount of fuel switching. Consequently, for steam generating units above 73 MW (250 million Btu/hour) heat input capacity, FGD systems are installed in response to requirements to achieve a percent reduction in SO_2 emissions. Below 73 MW (250 million Btu/hour) heat input capacity, however, a substantial number of steam generating units switch from oil or coal to natural gas to avoid the costs of FGD systems.

Fuel switching, therefore, tends to mitigate the costs of SO_2 control associated with requirements to achieve a percent reduction in emissions for steam generating units below 73 MW (250 million Btu/hour) heat input capacity, but not for steam generating units above 73 MW (250 million Btu/hour) heat input capacity. The result is that the incremental cost effectiveness of emission control increases significantly in progressing from regulatory alternative 2 to regulatory alternative 3, due to the requirement associated with alternative 3 to achieve a percent reduction in emissions from steam generating units above 73 MW (250 million Btu/hour) heat input capacity. It then decreases significantly in progressing from regulatory alternative 3 to regulatory alternative 4 as this requirement is extended from steam generating units above 73 MW (250 million Btu/hour) heat input capacity to steam generating units below 73 MW (250 million Btu/hour) heat input capacity.

As shown, the various regulatory alternatives examined under the high oil penetration scenario could reduce national SO_2 emissions by about 68,000 to 236,000 Mg/year (75,000 to 260,000 tons/year). National annualized costs, however, could be increased by about \$57 to \$133 million/year. The average cost effectiveness of emission control would range from about \$121 to \$562/Mg (\$110 to \$510/ton) of SO_2 removed and the incremental cost effectiveness between regulatory alternatives would generally be in the range of \$550 to \$1,270/Mg (\$500 to \$1,150/ton) of SO_2 removed.

Fuel switching of about 70 to 153 million GJ/year (66 to 145 trillion Btu/year) from oil or coal to natural gas could occur. This would result in an increase in natural gas combustion in new industrial-commercial-institutional steam generating units of about 45 to 95 percent. While this increase in natural gas combustion may seem high when expressed in this manner, it is negligible when compared to the current level of natural gas combustion in the industrial sector. As shown in Table 8-8, an increase of 153 million GJ/year (145 trillion Btu/year) in natural gas combustion in new industrial steam generating units, for example, represents an increase of only about 2 percent in total natural gas combustion over 1983 levels in the industrial sector. In addition, this increase in natural gas consumption by the industrial sector represents only a 1.5 percent increase over projected industrial gas consumption in 1990. The projected total natural gas production in 1990 is 22 billion GJ (21 quadrillion Btu). This production level is expected to be more than sufficient to meet the projected demand in 1990. Considered from this perspective, this fuel switching impact is minor.

The potential impact on coal combustion of all regulatory alternatives under the high oil penetration energy scenario is negligible. As shown in Table 8-7, coal combustion represents about 4.5 percent of new industrial steam generating unit energy consumption under the regulatory baseline. Regulatory alternative 2, which is based on the combustion of low sulfur fuels, could reduce this to 3.5 percent. Under regulatory alternative 6, which requires a percent reduction in SO_2 emissions, coal combustion could increase to about 5.5 percent. As shown in Table 8-9, whether the potential impacts of regulatory alternatives on coal markets under the high oil penetration scenario are considered in terms of national or Midwestern coal

TABLE 8-8. POTENTIAL NATIONAL NATURAL GAS MARKET IMPACTS

	1983 Consumption trillion Btu/year[a]	Maximum Increase in Consumption[b]		Projected 1990 Consumption, trillion Btu/year[a]	Maximum Increase in Consumption[b]	
		trillion Btu/year	Percent		trillion Btu/year	Percent
Industrial	6,700	145	2.1	9,500	145	1.5
Utility	3,000	-	-	2,400	-	
Total	9,700	145	1.5	11,900	145	1.2

[a]Total Energy Resource Analysis Model; American Gas Association; March 1985. Total natural gas consumption in the industrial and utility sectors.

[b]Change in consumption over baseline as a result of alternative SO_2 control levels.

TABLE 8-9. NATIONAL IMPACTS

Fossil Fuel-Fired Steam Generating Units

Potential Coal Market Impacts[a]

National Coal Markets					
o Coal Consumption	1982[b]		1990[c]		
- Utility	12,500		18,300		
- Industrial	2,600		3,700		
- Total	15,100		22,000		
o Potential NSPS Impact	High Oil Penetration		High Coal Penetration		
- Baseline	23		284		
- Low Sulfur Fuel	17		248		
- Percent Reduction	26		147		
Midwest Coal Markets	Eastern Coal Local	Eastern Coal Other	Western Coal	Total	
o Coal Consumption (1982)[b]	1545	1795	885	4225	
o Potential NSPS Impact (1990)					
- High Oil Penetration					
Baseline	1	3	0	4	
Low Sulfur Fuel	0	0	0	0	
Percent Reduction	6	5	0	11	
- High Coal Penetration					
Baseline	21	36	4	61	
Low Sulfur Fuel	0	42	11	53	
Percent Reduction	19	17	0	36	

[a]Impacts in trillion Btu/year.

[b]Coal Data 1981/1982; National Coal Association; 1983.

[c]Looking Ahead to 1995; National Coal Association; April 1982.

markets, the amount of coal involved is so small that all impacts are negligible.

The national impacts projected by IFCAM for each of the regulatory alternatives under the high coal penetration energy scenario are also summarized in Table 8-7. As shown, an anomaly appears to arise in progressing from regulatory alternative 2 to alternatives 3 and 4. The average cost effectiveness of emission control decreases and the incremental cost effectiveness becomes negative. This is a reflection of the lower costs associated with regulatory alternatives 3 and 4. Even though these alternatives are more stringent than regulatory alternative 2, as reflected by the emission decreases in progression from regulatory alternative 2 to regulatory alternatives 3 and 4, annualized costs decrease.

This anomaly is explained by the difference between the methodology used by IFCAM to select the least cost means of complying with regulatory alternatives and that used to calculate the national annualized costs resulting from compliance with regulatory alternatives. IFCAM selects the least cost means of complying with regulatory alternatives on an after-tax basis. Thus, factors such as depreciation and investment tax credits are considered in selecting the least cost means of compliance. In calculating national annualized costs, however, IFCAM compiles these costs on a before-tax basis. Thus, factors such as depreciation and investment tax credits are not considered.

As a result, as is often the case when the economics of two alternatives are very close, tax considerations may be sufficient to determine which of the two alternatives is more attractive. What may be more attractive in the absence of tax considerations may be less attractive in the presence of tax considerations.

For a number of steam generating units under the high coal penetration energy scenario, the economics of the decision to fire coal or to fire natural gas is very close in IFCAM, particularly for steam generating units below 73 MW (250 million Btu/hour) heat input. On an after-tax basis, the economics favor coal; on a before-tax basis, the economics favor natural gas (see Table 6-19).

In response to standards based on the use of low sulfur fuels, many steam generating units fire coal. When a requirement to achieve a percent reduction in SO_2 emissions from coal combustion is imposed, however, the economics of firing coal and installing an FGD system to reduce SO_2 emissions, compared to firing natural gas, favor the selection of natural gas. Thus, a number of steam generating units switch from firing coal to firing natural gas. For these steam generating units, coal, the fuel choice under low sulfur fuel standards, is less expensive than natural gas on an after-tax basis but more expensive than natural gas on a before-tax basis. Under standards based on achieving a percent reduction in emissions, IFCAM selects natural gas as the fuel choice because it is less expensive than firing coal and installing an FGD system (both before and after taxes). Firing natural gas has lower costs on a before-tax basis than those associated with firing coal under the low sulfur fuel alternative. Because IFCAM compiles annualized cost impacts on a before-tax basis, annualized costs decrease in this comparison rather than increase.

Under the high coal penetration scenario, this situation of a coal-fired steam generating unit being less expensive than a natural gas-fired steam generating unit on an after-tax basis, but more expensive on a before-tax basis, is sufficiently widespread for steam generating units below 73 MW (250 million Btu/hour) heat input capacity that in progressing from regulatory alternative 2 to regulatory alternatives 3 and 4, annualized costs, as well as SO_2 emissions, decrease. As a result, the incremental cost effectiveness of emission control between regulatory alternatives 2 and 3 and regulatory alternatives 3 and 4 is negative rather than positive.

As shown in Table 8-7, under the high coal penetration energy scenario, the various regulatory alternatives examined could reduce national emissions of SO_2 by about 191,000 to 281,000 Mg/year (210,000 to 310,000 tons/year). Annualized costs, however, could be increased by about \$20 to \$30 million/year. The average cost effectiveness of emission control would range from \$88 to \$198/Mg (\$80 to \$180/ton) of SO_2 removed and the incremental cost effectiveness of control would not exceed \$331/Mg (\$300/ton) of SO_2 removed.

Fuel switching from coal to natural gas, however, of about 40 to 143 million GJ/year (36 to 137 trillion Btu/year) could occur. This would result in an increase in natural gas combustion ranging from 20 to 70 percent and a decrease in coal combustion ranging from 13 to 48 percent in new steam generating units. As discussed earlier, if these fuel shifts are compared to current industrial sector energy demands, however, they are negligible. A shift of 148 million GJ/year (140 trillion Btu/year), for example, represents only about 2 percent of natural gas combustion, about 5 percent of coal combustion, and less than a 1 percent fuel shift in the total existing industrial sector energy market (see Table 8-9).

Unlike the high oil penetration scenario, under the high coal penetration scenario all regulatory alternatives result in projected decreases in coal combustion. Regulatory alternative 1, which is based on the combustion of low sulfur fuels, could reduce coal combustion from about 57 percent to about 50 percent of the total fuel combusted in new industrial-commercial-institutional steam generating units. Regulatory alternative 5, which requires a percent reduction in SO_2 emissions, would reduce this coal combustion from 57 percent to about 30 percent.

In terms of national or Midwestern coal markets, however, the magnitude of these potential impacts is minimal, as shown in Table 8-9. Even under the regulatory baseline, which yields the highest levels of projected coal combustion, coal combustion in new industrial-commercial-institutional steam generating units only represents about 1 percent of projected national coal combustion in 1990 and only about 7.5 percent of projected industrial steam generating unit coal combustion. The same is true in Midwestern coal markets, where projected coal combustion in new industrial-commercial-institutional steam generating units in 1990 only represents about 1.5 percent of actual coal combustion in the Midwest in 1982.

8.2 MIXED FUEL-FIRED STEAM GENERATING UNITS

As mentioned above, national impacts were also examined for mixed fuel-fired industrial-commercial-institutional steam generating units.

Mixed fuel-fired steam generating units may fire mixtures of fossil fuels but generally fire mixtures of fossil and nonfossil fuels.

As in the analysis discussed above for fossil fuel-fired steam generating units, the population of new industrial-commercial-institutional mixed fuel-fired steam generating units in 1990 was projected. The total costs of alternative fuel mixtures, including the costs of complying with environmental regulations, were then compared on an after-tax discounted cash flow basis for each steam generating unit over a 15-year investment period. The lowest cost combination of fuel mixture and emission control system was then determined for each steam generating unit. These results were then aggregated to yield national projections in 1990 of annualized costs, sulfur dioxide emissions, and solid and liquid wastes.

The magnitude of the national impacts associated with alternative control levels for new mixed fuel-fired steam generating units is a function of two major variables. These are the projected population of new mixed fuel-fired steam generating units (i.e., the overall number and size distribution of these units) and the projected fuel mixtures fired.

Little data and information are readily available concerning the current population, historical sales, or projected growth of mixed fuel-fired steam generating units. What little data and information are available, however, indicate that wood is the most common fuel fired in combination with various fossil fuels in mixed fuel-fired steam generating units. This is expected to be the case for new mixed fuel-fired steam generating units as well. Consequently, the limited data and information available for mixed fuel-fired steam generating units firing mixtures of wood and various fossil fuels were used to represent mixed fuel-fired steam generating units in general.

Data provided by the National Council of the Paper Industry for Air and Stream Improvement (NCASI) indicate that 35 mixed fuel-fired steam generating units were constructed during the five-year period from 1980 through 1984. These steam generating units had a combined heat input capacity of 5,850 MW (20.1 billion Btu/hour). This estimate of growth over the past five years is generally consistent with information also available from the American Boiler Manufacturers Association and the Department of Energy. In the absence of growth projections to the contrary, therefore, this was assumed to be the growth in new mixed fuel-fired steam generating units over the five years from 1985 through 1990. Data and information available from NCASI were also used to project the distribution of new mixed fuel-fired steam generating units by steam generating unit size, by composition of fuel mixture fired, and by the geographical location of new mixed fuel-fired steam generating units.

Prices for coal, residual oil, and natural gas are the same as those discussed previously. Data are generally unavailable on the cost or price of nonfossil fuels. In some cases these fuels could be "free," in the sense that they could not otherwise be sold in the open marketplace and there are negligible costs associated with their use as a fuel. In most cases, however, there is a real cost associated with the use of nonfossil fuels. It is unlikely, however, that the cost of these fuels would be higher than that of coal on a heating value basis. Consequently, two costs for nonfossil fuels were considered: zero cost; and the same cost, on a heating value basis, as the least expensive coal available.

As in the analysis discussed in "Consideration of Demonstrated Emission Control Technology Costs," this analysis of the national impacts for mixed fuel-fired steam generating units assumes no emission credits for dilution of the SO_2 emissions from combustion of fossil fuels with exhaust gases from the combustion of nonsulfur-bearing fuels. Consequently, to comply with an alternative control level based on the use of low sulfur fuels, a mixed fuel-fired steam generating unit would be required to fire a low sulfur fuel or install an FGD system to reduce SO_2 emissions.

Similarly, to comply with an alternative control level requiring a percent reduction in SO_2 emissions, a mixed fuel-fired steam generating unit would be required to achieve the specific percent reduction requirement included in the alternative control level. Dilution of the SO_2 emissions with exhaust gases resulting from the combustion of nonsulfur-bearing fuels would not permit a mixed fuel-fired steam generating unit to achieve a lower percent reduction requirement.

The merits of emission credits for mixed fuel-fired steam generating units, as well as emission credits for other types of steam generating units, are examined and discussed in "Consideration of Emission Credits."

Table 8-10 summarizes projected SO_2 emissions, annualized costs, and fuel consumption for new industrial-commercial-institutional mixed fuel-fired steam generating units in 1990. Given the relative prices projected for coal, residual oil, and natural gas, all new mixed fuel-fired steam generating units are projected to fire coal in combination with various nonfossil fuels.

8.2.1 Selection of Regulatory Alternatives

The "sensitivity" analysis of various alternative control levels for fossil fuel-fired steam generating units discussed above concluded that there is little difference in annualized costs among alternative control levels based on the use of low sulfur coal and little difference among alternative control levels requiring a percent reduction in SO_2 emissions under the high coal penetration scenario. Consequently, under this energy scenario the regulatory analysis examined only one alternative based on the use of low sulfur fossil fuel - that of reducing SO_2 emissions from coal combustion to 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input. Similarly, the regulatory analysis examined a single percent reduction requirement of 90 percent to represent the range of percent reduction requirements that could be included in new source performance standards.

As mentioned above, all new mixed fuel-fired steam generating units are projected to fire coal as the fossil fuel. Consequently, these two alternative control levels were selected as the basis of the regulatory alternatives examined. The potential impacts associated with four regulatory alternatives limiting SO_2 emissions from industrial-commercial-institutional mixed fuel-fired steam generating units were examined. These regulatory alternatives are presented in Table 8-11.

TABLE 8-10. NATIONAL IMPACTS

Mixed Fuel-Fired Steam Generating Units

Regulatory Baseline (Base Case)

1990

SO_2 emissions, thousand tons/year	69
Annualized costs, million $/year	425
Fuel use, trillion Btu/year	
∘ Coal/nonfossil	99
∘ Oil/nonfossil	0
∘ Natural gas/nonfossil	0

TABLE 8-11. REGULATORY ALTERNATIVES

Mixed Fuel-Fired Steam Generating Units

Regulatory Alternative[a]	Steam Generating Unit Heat Input Capacity (Million Btu/hr) 100-250	>250
Baseline	Base	Base
Alternative 1	Base	1.2 lb SO_2/million Btu
Alternative 2	1.2 lb SO_2 million Btu	1.2 lb SO_2/million Btu
Alternative 3	1.2 lb SO_2/million Btu	90% Reduction
Alternative 4	90% Reduction	90% Reduction

[a]Control levels shown for each regulatory alternative are SO_2 emission limits in lb SO_2/million Btu or a required percent reduction in SO_2 emissions. Emission limits and percent reduction requirements are based on fossil fuel heat input only.

8.2.2 Analysis of Regulatory Alternatives

The national impacts projected for each of the regulatory alternatives are summarized in Table 8-12. The total annualized costs presented in Table 8-12 are based on a zero cost or price for nonfossil fuels. The total annualized costs are higher when the cost or price of nonfossil fuels is assumed to be equal to that of coal. The incremental costs or cost impacts between alternatives, however, remain the same.

Table 8-12 shows that under the regulatory baseline the annualized costs for mixed fuel-fired steam generating units are about $425 million per year and the annual emissions are about 62,700 Mg/year (69,100 tons/year). Under regulatory alternative 1, annualized costs would be about $446 million/year, and annual emissions would be reduced to about 22,000 Mg/year (24,300 tons/year). Similar impacts result under regulatory alternative 2; annualized costs would be about $446 million/year, and annual emissions would be reduced to 25,600 Mg/year (23,200 tons/year). The actual cost increase of regulatory alternative 2 over regulatory alternative 1 would be about $400,000 per year. This increase is small because only five new steam generating units with heat input capacities of less than 73 MW (250 million Btu/hour) are projected. Furthermore, because these five steam generating units are projected to fire 20 percent fossil fuel, the cost impacts of firing a more expensive fossil fuel are minimized.

As discussed previously in the analysis of national impacts on fossil fuel-fired steam generating units, many fossil fuel-fired steam generating units electing to fire coal under the regulatory baseline, or under regulatory alternatives requiring the use of low sulfur fuel, would switch fuels and fire natural gas under a regulatory alternative requiring a percent reduction in SO_2 emissions. In these cases, natural gas firing represents the least cost means of complying with a regulatory alternative requiring a percent reduction in SO_2 emissions.

The results of this analysis, however, show that mixed fuel-fired steam generating units firing mixtures of coal and nonfossil fuels do not switch to firing natural gas under a regulatory alternative requiring a percent

TABLE 8-12. 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		Fuel Use Trillion Btu/yr		Quantity of Fuel Scrubbed Trillion Btu/yr	Liquid Waste Million ft^3/yr	Solid Waste 1,000 tons/yr
			Average	Incremental	Coal	Nonfossil			
Baseline	69.1	424.8	-	-	49	50	-	40	284
Alternative 1	24.3	445.9	470	-	49	50	-	40	281
Alternative 2	23.2	446.3	470	360	49	50	-	40	281
Alternative 3	8.2	470.0	740	1,580	49	50	95	149	286
Alternative 4	7.9	471.6	765	5,330	49	50	99	151	286

reduction in SO_2 emissions. Mixed fuel-fired steam generating units continue to fire mixtures of coal and nonfossil fuels under both the high oil and high coal penetration scenarios, even when the cost of nonfossil fuel is assumed to be equal to that of coal.

The large savings in capital costs that accrue by selecting a natural gas-fired steam generating unit instead of a coal-fired unit are not accrued when natural gas is fired in place of coal in a mixed fuel-fired steam generating unit. As a result, the choice of fossil fuels in mixed fuel-fired steam generating units is determined primarily by relative fuel prices. Because natural gas is projected to cost much more than coal under both of the energy price scenarios considered, no switching to natural gas occurs in mixed fuel-fired steam generating units even in response to standards that require a percent reduction in SO_2 emissions.

Under regulatory alternative 3, annualized costs would be about $470 million/year and annual emissions would be reduced to about 7,400 Mg/year (8,200 tons/year). Under regulatory alternative 4, annualized costs would be about $472 million/year and annual emissions would be reduced to 7,200 Mg/year (7,900 tons/year).

The average cost effectiveness of the various regulatory alternatives over the regulatory baseline ranges from about $520/Mg to $830/Mg ($470/ton to $765/ton) of SO_2 removed. The incremental cost effectiveness of regulatory alternative 2 over regulatory alternative 1 is about $400/Mg ($360/ton) of SO_2 removed. The incremental cost effectiveness of regulatory alternative 3 over regulatory alternative 2 is $1,740/Mg ($1,580/ton) of SO_2 removed. The incremental cost effectiveness of emission control increases significantly due to the requirement associated with regulatory alternative 3 to achieve a percent reduction in emissions from mixed fuel-fired steam generating units with heat input capacities above 73 MW (250 million Btu/hour). The large cost increase of a percent reduction requirement compared to a requirement based on the use of low sulfur coal results in a large increase in the incremental cost effectiveness value. The incremental cost effectiveness of regulatory alternative 4 over regulatory alternative 3 is $5,860/Mg ($5,330/ton) of SO_2 removed.

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 73 MW (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 29 and 73 MW (100 and 250 million Btu/hour) would also be required to achieve a percent reduction in SO_2 emissions. As mentioned previously, all of the projected new mixed fuel-fired steam generating units with heat input capacities in this range are expected to fire very small amounts of fossil fuel in relation to nonfossil fuel (on the order of 20 percent). As discussed previously, the incremental cost effectiveness of achieving a percent reduction in SO_2 emissions over the use of low sulfur fuel increases as the amount of fossil fuel fired decreases. Consequently, this high incremental cost effectiveness is not due to the smaller size of steam generating units included under regulatory alternative 4, but is due to the small amount of fossil fuel fired in mixed fuel-fired steam generating units with heat input capacities between 29 and 73 MW (100 and 250 million Btu/hour).

As discussed previously, 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 8-13 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 units with fossil fuel utilization factors of 0.48 or less; percent reduction for steam generating units with fossil fuel utilization factors above 0.30 and the use of low sulfur fuels for units with fossil

TABLE 8-13. NATIONAL IMPACTS: MIXED FUEL-FIRED STEAM GENERATING UNITS - IMPACTS AS A FUNCTION OF FOSSIL FUEL UTILIZATION FACTOR

Alternative	Annual Emissions, 1,000 Mg/year (1,000 tons/year)	Annualized Costs, \$ million	Average Cost Effectiveness, \$/Mg (\$/ton)	Incremental Cost Effectiveness,[b] \$/Mg (\$/ton)
Baseline (2.5 lb SO_2/million Btu)	62.7 (69.1)	424.8	-	-
Low Sulfur Fuel (1.2 lb SO_2/million Btu)	21.0 (23.2)	446.3	520 (470)	-
Percent Reduction for Fossil Fuel Utilization Factors >0.48[a]	21.0 (23.2)	446.3	520 (470)	0 (0)
Percent Reduction for Fossil Fuel Utilization Factors >0.30[a]	11.5 (12.7)	457.2	630 (570)	1,150 (1,040)
Percent Reduction for Fossil Fuel Utilization Factors >0.12[a]	9.7 (10.7)	460.2	670 (605)	1,610 (1,460)
Percent Reduction	7.2 (7.9)	471.6	840 (765)	4,575 (4,150)

[a]Steam generating units with fossil fuel utilization factors at or below the specified level are not required to achieve a percent reduction in SO_2 emissions but must meet an emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu).

[b]Over less stringent alternative.

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 fuels for units with fossil fuel utilization factors of 0.12 or less.

As shown in Table 8-13, 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 is \$0/Mg (\$0/ton) of SO_2 removed. This is because no 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 with fossil fuel utilization factors above 0.48, is \$1,150/Mg (\$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 \$1,610/Mg (\$1,460/ton) of SO_2 removed. The incremental cost effectiveness of requiring all steam generating units to achieve a percent reduction in SO_2 emissions over exempting units with fossil fuel utilization factors of 0.12 or less from a percent reduction requirement increases to \$4,575/Mg (\$4,150/ton) of SO_2 removed. Thus, as stated previously, the fossil fuel utilization factor at which a mixed fuel-fired steam generating unit operates directly affects the incremental cost effectiveness of achieving a percent reduction in SO_2 emissions compared to firing a low sulfur fuel to comply with an emission limit. As the fossil fuel utilization factor decreases, the incremental cost effectiveness increases.

9.0 CONSIDERATION OF INDUSTRY-SPECIFIC ECONOMIC IMPACTS

An analysis was undertaken to assess the potential industry-specific economic impacts associated with new source performance standards limiting SO_2 emissions from new industrial-commercial-institutional steam generating units. This analysis, however, focused on the potential impacts associated with a regulatory alternative requiring a percent reduction in SO_2 emissions. The industry-specific impacts associated with other regulatory alternatives, therefore, would be less than those discussed below.

The potential industry-specific economic impacts were analyzed in two phases. The first phase focused on aggregate economic impacts for major steam-using industries and estimated the potential impact on steam costs and product prices based on industry-wide averages for eight large industry groups. The groups selected for analysis account for approximately 70 percent of domestic industrial steam consumption. These eight industry groups were: food; textiles; paper; chemicals; petroleum refining; stone, clay, and glass; iron and steel; and aluminum.

To determine the potential product price impacts of a percent reduction requirement, estimates were made of steam consumption per dollar of product sales by industry group. Projected growth in product sales and the resulting increased steam demands were then estimated by industry group. Next, steam cost increases attributable to the percent reduction requirement were estimated based on annualized steam generating unit and pollution control costs. Assuming full cost pass-through of these increased costs to product prices, the potential impact of this regulatory alternative on product prices was estimated.

Growth projections indicate that from less than 1 to 9 percent of the steam consumption in the eight major steam-using industries would be generated in new steam generating units subject to the proposed standards by 1990. Average steam costs in these industry groups would increase about \$0.09 to \$0.25/GJ (\$0.09 to \$0.24/million Btu) of heat input. Assuming full cost pass-through of increased steam costs, product prices in the major industry groups would increase by less than 0.03 percent. This potential impact represents a maximum product price increase because of the full cost pass-through assumption. In some instances, increased steam costs would not be completely passed through to product prices, and, therefore, the impact on product prices would be less.

The second phase of the analysis focused on selected industries that were considered likely to experience the most severe impacts. Seven industries were selected due to the steam-intensive nature of their operation or the low utilization of their steam generating unit capacity. These industries were beet sugar refining, fruit and vegetable canning, rubber reclaiming, automobile manufacturing, petroleum refining, iron and steel manufacturing, and liquor distilling.

The economic impact analysis examined potential impacts on prices, value added, profitability, and capital availability. This analysis was based on "model" plants and "model" firms representative of each industry.

Model plants were defined for each industry based on historical plant locations, fuel use, and steam generating unit construction patterns. Annual plant sales, plant product output, product costs, and return on assets were estimated for each model plant. Then, based on recent trends in each industry, a scenario was developed involving existing steam generating unit replacement, or construction of additional steam generating unit capacity for plant expansion at each model plant. Based on these scenarios, increased steam costs imposed on model plants by requirements to achieve a percent reduction in SO_2 emissions were calculated.

Assuming full cost pass-through of steam cost increases, the potential impact of a percent reduction requirement on product prices and value added could be estimated. To estimate the potential impact on profitability, or return on assets, an analysis was also conducted assuming full cost absorption of increased steam costs with no pass-through.

Based on scenarios involving replacement of from 25 to 90 percent of existing steam generating unit capacity with new steam generating unit capacity at model plants for the seven industries selected, product prices were projected to increase from less than 0.01 to 0.5 percent in 1990 for all except the beet sugar refining industry, assuming full cost pass-through of increased steam costs. As shown in Table 9-1, the fruit and vegetable canning industry showed no impacts due to the assumption that all new steam generating unit capacity in this industry would be natural gas-fired.

For these same seven industries, value added was projected to increase by about 0.01 to 0.9 percent in 1990 for all except the beet sugar refining industry, assuming full cost pass-through of increased steam costs.

For both product price and value added impacts, the highest increases are projected for the beet sugar refining industry. In the case of product prices, this is due to the fact that the product price is low and steam costs represent an unusually high proportion of manufacturing costs in the beet sugar refining industry, compared to the other industries examined. Similarly, value added impacts are higher since steam costs represent an unusually high proportion of the non-raw material costs of manufacturing the product in the beet sugar refining industry, compared to the other industries examined.

Based on the same scenarios outlined above, but assuming full cost absorption of increased steam costs, return on assets was projected to decrease by 0.03 to 2.8 percentage points. Again, these potential impacts represent "worse case" projections because of the assumption of full cost absorption of the increased steam costs.

The analysis of potential impacts on capital availability examined the impact of a percent reduction requirement on the ability of "model" firms to finance pollution control expenditures. Corporate annual reports and Securities and Exchange Commission Forms 10-K were reviewed to formulate a hypothetical financial position and to identify the number of operating plants for each model firm. Each plant operated by the model firm was assumed to be identical to the corresponding model plant used in the analysis discussed above. The potential impact of a percent reduction requirement on each model firm's cash flow, coverage ratio, and debt/equity ratio under two debt/equity financing strategies was estimated based on the amount of financing needed to construct replacement or expansion steam generating units.

TABLE 9-1. SUMMARY OF CHANGE IN PRODUCT COST AND RETURN ON ASSETS FOR MODEL PLANTS AND FIRMS IN SELECTED INDUSTRIES

Industry	Model Plant Increase in Product Cost (Percent)	Model Plant Increase in Value Added (Percent)	Model Firm Return on Assets: Base Case[1] (Percent)	Model Firm Return on Assets: SO_2 Alternative Control Level[2] (Percent)
Beet Sugar Refining	1.50	5.00	2.30	1.50
Fruit and Vegetable Canning[3]	-	-	-	-
Rubber Reclaiming	0.50	0.90	3.80	1.00
Auto Manufacturing	<0.01	0.01	9.17	9.14
Petroleum Refining	0.02	0.14	5.98	5.93
Iron and Steel Manufacturing	0.10	0.25	3.36	3.28
Liquor Distilling	0.12	0.24	0.68	0.37

[1] Base case includes proposed PM/NO_x NSPS and current SO_2 SIP regulations.

[2] The SO_2 alternative control level is a percent reduction requirement for all steam generating units greater than 100 million Btu/hour.

[3] Fruit and vegetable canning have no impacts, since new steam generators are natural gas-fired units.

Cash flow coverage ratios and book debt/equity ratios showed essentially no change for any of the model firms under the two different debt/equity financing strategies. Consequently, a percent reduction requirement would not impair the ability of firms to raise sufficient capital to construct new steam generating units.

The industry-specific economic impacts analysis, therefore, indicates that a percent reduction requirement would generally increase product prices and value added by less than 1 percent if all steam cost increases were passed through to product prices. In addition, assuming absorption of all steam cost increases, return on assets would generally decrease by about 3 percentage points or less. Cash flow coverage and book debt/equity ratios showed essentially no change. Therefore, a percent reduction requirement would not impose any capital availability constraints on firms.

As mentioned earlier, a percent reduction requirement is the most stringent regulatory alternative considered. Consequently, the industry-specific economic impacts associated with other regulatory alternatives would be less severe than those discussed above.

10.0 CONSIDERATION OF EMISSION CREDITS

Emission credits have been suggested for two general types of industrial-commercial-institutional steam generating units: cogeneration steam generating units and mixed fuel-fired steam generating units. Emission credits would permit higher emissions from these units.

10.1 COGENERATION STEAM GENERATING UNITS

Cogeneration systems are defined as energy systems that simultaneously produce both electrical (or mechanical) energy and thermal energy from the same primary energy source. Cogeneration systems are efficient electric/thermal energy production technologies with a potential for local and regional energy savings and emission reductions.

Following adoption of the Public Utility Regulatory Policies Act of 1978 (PURPA), there has been increasing interest in the cogeneration of electricity at industrial, commercial, and institutional sites. Under PURPA, qualifying cogenerators may sell their excess electrical power directly to electric utility companies at the utilities' avoided cost, which makes on-site cogeneration economically attractive in many cases.

10.1.1 Steam Generator-Based Cogeneration Systems

In a steam generator-based cogeneration system, the simultaneous production of electric power and process heat is achieved by supplying the steam produced by an industrial-commercial-institutional steam generating unit to a steam turbine/electric generator set for electric power generation and then recovering process or space heat from the steam turbine exhaust. The steam generating unit used for an on-site cogeneration system would be slightly larger than otherwise required. However, the total fuel use by a cogeneration system is less than the combined total of the fuel used at a utility steam generating unit to generate electricity and the fuel used by an industrial-commercial-institutional steam generating unit to provide process or space heat.

The potential for regional energy savings through the use of a steam generator-based cogeneration system, compared to the use of separate steam generating units for electric power generation and process or space heat production, can range from 5 percent to almost 30 percent depending on the specific industry using the cogeneration system and the type of fuel used. This reduced regional fuel consumption can translate into regional air pollution emission reductions under certain conditions. For example, if a cogeneration system reduces regional fuel use by 15 percent and displaces a utility steam generating unit firing the same fuel, and subject to the same emission limitation, regional emissions would also be reduced by 15 percent.

Because of this emission reduction potential, it has been suggested that new source performance standards for industrial-commercial-institutional steam generating units should include some type of "emission credit" for the higher efficiencies achieved by cogeneration systems. Such a credit, according to its proponents, would reduce the cost of air pollution control at a cogeneration site, result in equivalent regional emissions, and encourage the use of cogeneration systems.

If an emission credit were allowed for cogeneration systems, it would adjust (increase) the emission limitation for cogeneration steam generating units, offsetting any regional emission reduction that might occur from the use of the cogeneration system. For example, for a coal-fired steam generating unit subject to an SO_2 emission limit of 516 ng/J (1.2 lb/million Btu) heat input, a 15 percent emission credit reflecting the potential decrease in regional emissions would increase the emission limit to 593 ng SO_2/J (1.38 lb SO_2/million Btu) heat input. Similarly, for a coal-fired steam generating unit subject to a percent reduction requirement of 70 or 90 percent reduction in emissions, a 15 percent emission credit would decrease the percent reduction requirement to 65.5 or 88.5 percent, respectively.

In addition, it may be quite difficult to identify the appropriate emission credit for specific cogeneration systems. In cases where different emission standards are applicable to the displaced fuel at a utility steam generating unit and the fuel used in the cogeneration system, or different fuels are fired in the utility steam generating unit than in the cogeneration system, the environmental and fuel use impacts of cogeneration become less clear. For example, in cases where a new cogeneration system achieves emission levels that are lower than those from the utility steam generating unit, a 15 percent regional energy savings may result in more than a 15 percent reduction in regional emissions. Conversely, if the cogeneration system results in emissions higher than the utility steam generating unit, a 15 percent regional energy savings may result in less than a 15 percent emission reduction. If hydroelectric or nuclear power generation capacity is being replaced by cogeneration, regional emissions increase.

Also of importance to local emissions is the fact that a larger industrial-commercial-institutional steam generating unit is used in the cogeneration system than would otherwise be used. Consequently, local emissions at the cogeneration site increase in all cases.

To assess the reasonableness of emission credits for steam generator-based cogeneration systems, the cost effectiveness of SO_2 emission control associated with not providing emission credits was examined. This analysis compared the cost effectiveness of SO_2 control among a conventional industrial-commercial-institutional steam generating unit, a cogeneration steam generating unit without emission credits, and a cogeneration steam generating unit with emission credits, and calculated the incremental cost effectiveness of not providing emission credits.

As discussed earlier, the annual capacity factor at which a steam generating unit operates can have a significant influence on the cost effectiveness of emission control. Conventional industrial-commercial-institutional steam generating units generally operate at annual capacity factors in the range of 0.6. Cogeneration steam generating units, however, operate at much higher annual capacity factors, generally in the range of 0.9. Therefore, an annual capacity factor of 0.9 was used in the analysis of emission credits for cogeneration steam generating units.

As mentioned above, the potential for regional energy savings, reduced fuel consumption, and reduced air pollutant emissions resulting from cogeneration is in the range of 5 to 30 percent. If standards based on the use of low sulfur fuels limited SO_2 emissions from coal-fired steam generating units to 516 ng/J (1.2 lb/million Btu) heat input and SO_2 emissions from oil-fired units to 345 ng/J (0.8 lb/million Btu) heat input, an emission credit of 30 percent would effectively increase these emission limits to 670 and 450 ng/J (1.56 and 1.04 lb/million Btu) heat input, respectively.

Fuel pricing data are not available for low sulfur fuels that could reduce SO_2 emissions to these levels, but not to 516 and 345 ng/J (1.2 and 0.8 lb/million Btu) heat input. Pricing data are available, however, for low sulfur fuels that could reduce SO_2 emissions to 730 and 690 ng/J (1.7 and 1.6 lb/million Btu) heat input for coal and oil, respectively. As a result, emission limits of 730 and 690 ng SO_2/J (1.7 and 1.6 lb SO_2/million Btu) heat input were used to represent the effect of emission credits. These emission levels, however, represent emission credits greater than 30 percent. For example, an emission limit of 730 ng SO_2/J (1.7 lb SO_2/million Btu) heat input represents a credit of 42 percent compared to an emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu) heat input for coal-fired steam generating units. Similarly, an emission limit of 690 ng SO_2/J (1.6 lb SO_2/million Btu) heat input represents an emission credit of 100 percent compared to an emission limit of 345 ng SO_2/J (0.8 lb SO_2/million Btu) heat input for oil-fired steam generating units.

An emission credit of 30 percent was used to assess the reasonableness of emission credits for standards which require a percent reduction in emissions. For a standard requiring a 90 percent reduction in emissions, a 30 percent emission credit would reduce this percent reduction requirement to 87 percent. Thus, percent reduction requirements of 90 and 87 percent were used to assess the reasonableness of emission credits for coal- and oil-fired cogeneration steam generating units under standards requiring a percent reduction in emissions.

As shown in Tables 10-1 and 10-2, the cost effectiveness of SO_2 control for standards based on the use of low sulfur coal are similar for a conventional industrial-commercial-institutional steam generating unit, a cogeneration steam generating unit without an emission credit, and a cogeneration unit with an emission credit. For example, the average cost effectiveness of SO_2 emission control in Region V is $454/Mg ($412/ton) for a conventional steam generating unit, $460/Mg ($417/ton) for a cogeneration unit without an emission credit, and $340/Mg ($309/ton) of SO_2 removed for a cogeneration unit with an emission credit. Similarly, in Region VIII the average cost effectiveness of emission control is $243/Mg ($221/ton) for a conventional steam generating unit, $242/Mg ($220/ton) for a cogeneration unit without an emission credit, and $359/Mg ($326/ton) of SO_2 removed for a cogeneration unit with an emission credit.

The same is true for the cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions from coal-fired steam generating units. The incremental cost effectiveness of SO_2 emission control associated with standards requiring a percent reduction in emissions over standards based on the use of low sulfur fuels in Region V is $961/Mg ($871/ton) for a conventional steam generating unit, $863/Mg ($784/ton) for a cogeneration unit without an emission credit, and $819/Mg ($742/ton) of SO_2 removed for a cogeneration unit with an emission credit. Similarly, in Region VIII the incremental cost effectiveness of emission control is $1,314/Mg ($1,192/ton) for a conventional steam generating unit, $1,261/Mg ($1,145/ton) for a cogeneration unit without an emission credit, and $838/Mg ($760/ton) of SO_2 removed for a cogeneration unit with an emission credit.

As shown in Table 10-3, the incremental cost effectiveness of not providing emission credits with standards based on the use of low sulfur coal is $614/Mg ($556/ton) in Region V and $92/Mg ($83/ton) of SO_2 removed in Region VIII. Similarly, the incremental cost effectiveness of not providing emission credits with standards requiring a percent reduction in emissions is only $300/Mg ($273/ton) in Region V and $556/Mg ($500/ton) of SO_2 removed in Region VIII.

TABLE 10-1. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COGENERATION COAL-FIRED STEAM GENERATING UNITS IN REGION V[a]

Steam Generating Unit	Fuel Type,[b] ng SO_2/J (lb SO_2/million Btu)	Annualized Costs, $1,000/yr	Annual Emissions, Mg/yr (tons/yr)	Average Cost Effectiveness,[c] $/Mg ($/ton)	Incremental Cost Effectiveness,[d] $/Mg ($/ton)
Conventional Unit, 44 MW (150 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	8,710	1,125 (1,240)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	8,990	508 (560)	454 (412)	-
Percent Reduction (90 Percent)	2,384 (5.54)	9,260	227 (250)	612 (556)	961 (871)
Cogeneration Unit W/O Credit, 53 MW (180 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	10,088	1,352 (1,490)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	10,430	608 (670)	460 (417)	-
Percent Reduction (90 Percent)	2,384 (5.54)	10,720	272 (300)	585 (531)	863 (784)
Cogeneration Unit W/Credit, 53 MW (180 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	10,088	1,352 (1,490)	-	-
Low Sulfur Coal, 731 ng/J (1.7 lb/million Btu)[e]	624 (1.45)	10,230	934 (1,030)	340 (309)	-
Percent Reduction (87 Percent)[f]	2,384 (5.54)	10,690	372 (410)	614 (558)	819 (742)

[a]Based on a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Compared to regulatory baseline.

[d]Compared to low sulfur fuel alternative.

[e]With a 30 percent emission credit, a low sulfur coal emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu) would increase to 671 ng SO_2/J (1.56 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[f]Based on a 30 percent emission credit.

TABLE 10-2. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COGENERATION COAL-FIRED STEAM GENERATING UNITS IN REGION VIII[a]

Steam Generating Unit	Fuel Type,[b] ng SO_2/J (lb SO_2/million Btu)	Annualized Costs, $1,000/yr	Annual Emissions, Mg/yr (tons/yr)	Average Cost Effectiveness,[c] $/Mg ($/ton)	Incremental Cost Effectiveness,[d] $/Mg ($/ton)
Conventional Unit, 44 MW (150 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	6,710	1,125 (1,240)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	6,860	508 (560)	243 (221)	-
Percent Reduction (90 Percent)	409 (0.95)	7,480	36 (40)	707 (642)	1,314 (1,192)
Cogeneration Unit W/O Credit, 53 MW (180 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	7,680	1,352 (1,490)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	7,860	608 (670)	242 (220)	-
Percent Reduction (90 Percent)	409 (0.95)	8,570	45 (50)	681 (618)	1,261 (1,145)
Cogeneration Unit W/Credit, 53 MW (180 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	7,680	1,352 (1,490)	-	-
Low Sulfur Coal, 731 ng/J (1.7 lb/million Btu)[e]	624 (1.45)	7,830	934 (1,030)	359 (326)	-
Percent Reduction (87 Percent)[f]	409 (0.95)	8,560	63 (70)	683 (620)	838 (760)

[a]Based on a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Compared to regulatory baseline.

[d]Compared to low sulfur fuel alternative.

[e]With a 30 percent emission credit, a low sulfur coal emission limit of 516 ng SO_2/J (1.2 lb SO_2/million Btu) would increase to 671 ng SO_2/J (1.56 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[f]Based on a 30 percent emission credit.

TABLE 10-3. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING EMISSION CREDITS FOR COAL-FIRED COGENERATION UNITS

	REGION V			REGION VIII		
	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $Mg ($/ton)	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $/Mg ($/ton)
Low Sulfur Coal						
With emission credit	10,230	934 (1,030)	-	7,830	934 (1,030)	-
Without emission credit	10,430	608 (670)	614 (556)	7,860	608 (670)	92 (83)
Percent Reduction						
With emission credit	10,690	372 (410)	-	8,560	63 (70)	-
Without emission credit	10,720	272 (300)	300 (273)	8,570	45 (50)	556 (500)

Table 10-4 summarizes the cost effectiveness of SO_2 control for oil-fired steam generating units. For standards based on the use of low sulfur oil, the average cost effectiveness of SO_2 control for a conventional steam generating unit is $562/Mg ($510/ton), compared with $544/Mg ($494/ton) for a cogeneration steam generating unit without an emission credit and $487 Mg ($442/ton) of SO_2 removed for a cogeneration steam generating unit with an emission credit.

For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of emission control over standards based on the use of low sulfur fuel is $275/Mg ($250/ton) for a conventional steam generating unit, $254/Mg ($231/ton) for a cogeneration unit without an emission credit, and $506/Mg ($459/ton) of SO_2 removed for a cogeneration unit with an emission credit.

As shown in Table 10-5, the incremental cost effectiveness of not providing emission credits is $640/Mg ($581/ton) for standards based on the use of low sulfur fuel and $182/Mg ($167/ton) of SO_2 removed for standards requiring a percent reduction in SO_2 emissions.

10.1.2 Combined Cycle or Gas Turbine-Based Cogeneration Systems

Combined cycle systems represent another type of cogeneration technology and consist of a gas turbine which discharges its exhaust into a steam generating unit. The steam generating unit is used to recover heat from the gas turbine exhaust. Steam generating units used in combined cycle systems fall into one of three categories, depending on how much fuel is fired in the steam generating unit: unfired, supplementary-fired, and fully-fired.

In the unfired arrangement, all of the heat input to the steam generating unit is supplied by the gas turbine exhaust. In the supplementary-fired arrangement, the gas turbine exhaust provides approximately 70 percent of the heat input to the steam generating unit, with the remaining 30 percent being supplied by the fuel fired in the steam generating unit. In the fully-fired arrangement, the gas turbine exhaust

TABLE 10-4. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COGENERATION OIL-FIRED STEAM GENERATING UNITS[a]

Steam Generating Unit	Fuel Type,[b] ng SO_2/J (lb SO_2/million Btu)	Annualized Costs, $1,000/yr	Annual Emissions, Mg/yr (tons/yr)	Average Cost Effectiveness,[c] $/Mg ($/ton)	Incremental Cost Effectiveness,[d] $/Mg ($/ton)
Conventional Unit, 44 MW (150 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	7,190	1,606 (1,770)	-	-
Low Sulfur Oil, 344 ng/J (0.8 lb/million Btu)[e]	1,291 (3.0)	7,860	413 (455)	562 (510)	-
Percent Reduction (90 Percent)	1,291 (3.0)	7,940	122 (135)	505 (459)	275 (250)
Cogeneration Unit W/O Credit, 53 MW (180 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	8,490	1,932 (2,130)	-	-
Low Sulfur Oil, 344 ng/J (0.8 lb/million Btu)[e]	1,291 (3.0)	9,270	499 (550)	544 (494)	-
Percent Reduction (90 Percent)	1,291 (3.0)	9,360	145 (160)	487 (442)	254 (231)
Cogeneration Unit W/Credit, 53 MW (180 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	8,490	1,932 (2,130)	-	-
Low Sulfur Oil, 688 ng/J (1.6 lb/million Btu)[f]	688 (1.6)	8,930	1,030 (1,135)	487 (442)	-
Percent Reduction (87 Percent)[g]	1,291 (3.0)	9,350	200 (220)	497 (450)	506 (459)

[a]Assumes a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Compared to regulatory baseline.

[d]Compared to low sulfur fuel alternative.

[e]Less expensive to fire a high sulfur oil [1,291 ng SO_2/J (3 lb SO_2/million Btu)] and install an FGD system to achieve 73 percent reduction than to purchase a low sulfur oil [344 ng SO_2/J (0.8 lb SO_2/million Btu)].

[f]With a 30 percent emission credit, a low sulfur oil emission limit of 344 ng SO_2/J (0.8 lb SO_2/million Btu) would increase to 447 ng SO_2/J 1.04 lb SO_2/million Btu. Pricing data are not available, however, for an oil capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 100 percent in order to use available pricing data for an oil meeting a 688 ng SO_2/J (1.6 lb SO_2/million Btu) emission limit.

[g]Based on a 30 percent emission credit.

TABLE 10-5. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING EMISSION CREDITS FOR OIL-FIRED COGENERATION UNITS

	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $/Mg ($/ton)
Low Sulfur Oil			
With emission credit	8,930	1,030 (1,135)	-
Without emission credit	9,270[a]	499 (550)[a]	640 (581)
Percent Reduction			
With emission credit	9,350	200 (220)	-
Without emission credit	9,360	145 (160)	182 (167)

[a]Based on firing a high sulfur oil [1,291 ng SO_2/J (3.0 lb SO_2/million Btu)] and using an FGD system to achieve 73 percent reduction.

provides approximately 25 percent of the heat input to the steam generating unit, with the remaining 75 percent being supplied by fuel fired in the steam generating unit.

The steam generating unit in an unfired and supplementary-fired combined cycle system is typically a modular finned-type heat exchanger. In a supplementary-fired combined cycle system, a duct burner is generally located upstream of the heat exchanger. Thermal limitations inherent in modular-type heat exchangers limit the amount of supplementary fuel fired in the duct burner. Also, because of potential fouling problems, only clean fuels such as natural gas or fuel oil are used in supplementary-fired combined cycle systems.

Fully-fired combined cycle systems employ a conventional steam generating unit and the firing rate in the steam generating unit is not restricted by thermal limitations. Sufficient fuel is fired in the steam generating unit to reduce the oxygen content of the gas turbine exhaust to approximately 3 percent or less, as is typically achieved in conventional steam generating units.

To date, as a result of both technical and economic considerations, both supplementary-fired and fully-fired combined cycle steam generating units have been constructed to fire either natural gas or fuel oil. Coal has not been fired in a combined cycle steam generating unit. The combustion of coal in an atmosphere of 15 percent or less oxygen (gas turbine exhaust) could lead to combustion stability problems. In addition, the handling, preparation, and firing of coal greatly increase the complexity and cost of a combined cycle steam generating unit. If coal were fired in a combined cycle steam generating unit it would be fired in a fully-fired system, rather than a supplementary-fired system, because of the fouling and erosion problems that would be experienced by modular heat exchangers used in supplementary-fired steam generating units.

To assess the reasonableness of emission credits for combined cycle cogeneration systems, the cost effectiveness of SO_2 control for combined cycle steam generating units was analyzed. This analysis compared the cost effectiveness of SO_2 control between conventional steam generating units, combined cycle steam generating units without emission credits, and combined cycle steam generating units with emission credits. In addition, the incremental cost effectiveness of SO_2 control as a result of not providing emission credits for combined cycle steam generating units was examined.

As mentioned earlier, the typical cogeneration system operates at a much higher capacity factor than the typical conventional steam generating unit. Consequently, as in the analysis of emission credits for steam-based cogeneration systems discussed above, a capacity factor of 0.9 was used in the analysis of emission credits for combined cycle cogeneration systems.

The emission credit for each type of combined cycle system was based on the amount of heat provided by the gas turbine exhaust to the steam generating unit. The magnitude of the emission credit, therefore, was determined by dividing the total heat input to the steam generating unit (i.e., gas turbine exhaust plus fuel fired in the steam generating unit) by the heat input to the steam generating unit provided by the fuel fired in the steam generating unit. For fully-fired combined cycle systems, the emission credit is in the range of 30 to 35 percent, depending on whether coal or oil is the fuel fired in the steam generating unit. For supplementary-fired combined cycle systems, the emission credit is somewhat greater than 200 percent, because most of the heat input to the steam generating unit in this type of combined cycle system is provided by the gas turbine exhaust.

As in the analysis discussed above for steam-based cogeneration systems, however, these emission credits were increased in several cases to reflect the fuel pricing data available. As a result, the analysis of the reasonableness of emission credits for combined cycle systems under standards based on the use of low sulfur fuel actually examined emission credits of 42 percent for fully-fired combined cycle systems using coal, 100 percent for fully-fired combined cycle systems using oil, and 275 percent for supplementary-fired combined cycle systems using oil. For standards requiring a percent reduction in SO_2 emissions, the actual emission credits examined were 40 percent for fully-fired combined cycle systems using coal, 30 percent for fully-fired combined cycle systems using oil, and 215 percent for supplementary-fired combined cycle systems using oil.

Tables 10-6 and 10-7 summarize the cost effectiveness of SO_2 control for a fully-fired coal-fired combined cycle steam generating unit. For standards based on the use of low sulfur fuel, the average cost effectiveness of SO_2 control in Region V is \$456/Mg (\$413/ton) for both a conventional steam generating unit and a combined cycle steam generating unit without an emission credit. For a combined cycle steam generating unit with an emission credit, the average cost effectiveness is \$339/Mg (\$308/ton) of SO_2 removed. In Region VIII, the average cost effectiveness of SO_2 control for both a conventional steam generating unit and a combined cycle steam generating unit without an emission credit is \$216/Mg (\$196/ton). For a combined cycle steam generating unit with an emission credit, the average cost effectiveness of SO_2 control is \$381/Mg (\$346/ton).

For standards which require a percent reduction in SO_2 emissions, the incremental cost effectiveness of SO_2 control over standards based on the use of low sulfur fuels in Region V is \$1,264/Mg (\$1,150/ton) for a conventional steam generating unit, \$1,429/Mg (\$1,300/ton) for a combined cycle steam generating unit without an emission credit, and \$1,207/Mg (\$1,094/ton) of SO_2 removed for a combined cycle steam generating unit with an emission credit. In Region VIII the incremental cost effectiveness of SO_2 control is \$1,521/Mg (\$1,382/ton) for a conventional steam generating unit, \$1,618/Mg (\$1,471/ton) for a combined cycle steam generating unit without an emission credit, and \$1,019/Mg (\$925/ton) of SO_2 removed for a combined cycle steam generating unit with an emission credit.

The incremental cost effectiveness of not providing an emission credit for fully-fired coal combined cycle systems is shown in Table 10-8. For standards based on the use of low sulfur coal, the incremental cost effectiveness is \$608/Mg (\$550/ton) of SO_2 removed in Region V. In Region VIII the incremental cost effectiveness of not providing an emission credit is \$0/Mg (\$0/ton) of SO_2 removed. Although SO_2 emissions increase as a result of providing an emission credit, costs do not decrease and, as a result, the incremental cost effectiveness of not providing an emission

TABLE 10-6. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COMBINED CYCLE STEAM GENERATING UNITS IN REGION V[a]

Fully-Fired Coal

Steam Generating Unit	Fuel Type,[b] ng SO_2/J (lb SO_2/million Btu)	Annualized Costs[c], $1,000/yr	Annual Emissions, Mg/yr (tons/yr)	Average Cost Effectiveness,[d] $/Mg ($/ton)	Incremental Cost Effectiveness,[e] $/Mg ($/ton)
Conventional Unit, 29 MW (100 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	2,430	753 (830)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	2,620	336 (370)	456 (413)	-
Percent Reduction (90 Percent)	2,384 (5.54)	2,850	154 (170)	701 (636)	1,264 (1,150)
Combined Cycle Unit W/O Credit, 40 MW (137 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	2,430	753 (830)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	2,620	336 (370)	456 (413)	-
Percent Reduction (90 Percent)	2,384 (5.54)	2,880	154 (170)	751 (682)	1,429 (1,300)
Combined Cycle Unit W/Credit, 40 MW (137 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	2,430	753 (830)	-	-
Low Sulfur Coal, 731 ng/J (1.7 lb/million Btu)[f]	624 (1.45)	2,510	517 (570)	339 (308)	-
Percent Reduction (86 Percent)[g]	2,384 (5.54)	2,860	227 (250)	817 (741)	1,207 (1,094)

[a]Based on a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Annual cost only includes cost of fuel fired plus annualized cost of SO_2 control device and does not include other steam generating unit operating and maintenance costs or annualized cost of the steam generating unit.

[d]Compared to regulatory baseline.

[e]Compared to low sulfur fuel alternative.

[f]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 137/100, or 37 percent. This would translate into an emission limit of 706 ng SO_2/J (1.64 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[g]Based on a 40 percent emission credit.

TABLE 10-7. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COMBINED CYCLE STEAM GENERATING UNITS IN REGION VIII[a]

Fully-Fired Coal

Steam Generating Unit	Fuel Type,[b] ng SO_2/J (lb SO_2/million Btu)	Annualized Costs[c], $1,000/yr	Annual Emissions, Mg/yr (tons/yr)	Average Cost Effectiveness,[d] $/Mg ($/ton)	Incremental Cost Effectiveness,[e] $/Mg ($/ton)
Conventional Unit, 29 MW (100 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	1,010	753 (830)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	1,100	336 (370)	216 (196)	-
Percent Reduction (90 Percent)	409 (0.95)	1,570	27 (30)	771 (700)	1,521 (1,382)
Combined Cycle Unit W/O Credit, 40 MW (137 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	1,010	753 (830)	-	-
Low Sulfur Coal, 516 ng/J (1.2 lb/million Btu)	409 (0.95)	1,100	336 (370)	216 (196)	-
Percent Reduction (90 Percent)	409 (0.95)	1,600	27 (30)	813 (738)	1,618 (1,471)
Combined Cycle Unit W/Credit, 40 MW (137 million Btu/hr)					
Regulatory Baseline, 1,076 ng/J (2.5 lb/million Btu)	904 (2.10)	1,010	753 (830)	-	-
Low Sulfur Coal, 731 ng/J (1.7 lb/million Btu)[f]	624 (1.45)	1,100	517 (570)	381 (346)	-
Percent Reduction (86 Percent)[g]	409 (0.95)	1,590	36 (40)	809 (734)	1,019 (925)

[a]Based on a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Annual cost only includes cost of fuel fired plus annualized cost of SO_2 control device and does not include other steam generating unit operating and maintenance costs or annualized cost of the steam generating unit.

[d]Compared to regulatory baseline.

[e]Compared to low sulfur fuel alternative.

[f]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 137/100, or 37 percent. This would translate into an emission limit of 706 ng SO_2/J (1.64 lb SO_2/million Btu). Pricing data are not available, however, for a coal capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 42 percent in order to use available pricing data for a coal meeting a 731 ng SO_2/J (1.7 lb SO_2/million Btu) emission limit.

[g]Based on a 40 percent emission credit.

TABLE 10-8. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING EMISSION CREDITS FOR COMBINED CYCLE UNITS

Fully-Fired Coal

	REGION V			REGION VIII		
	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $/Mg ($/ton)	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $/Mg ($/ton)
Low Sulfur Coal						
With emission credit	2,510	517 (570)	-	1,100	517 (570)	-
Without emission credit	2,620	336 (370)	608 (550)	1,100	336 (370)	0 (0)
Percent Reduction						
With emission credit	2,860	227 (250)	-	1,590	36 (40)	-
Without emission credit	2,880	154 (170)	274 (250)	1,600	27 (30)	1,111 (1,000)

credit is \$0/Mg (\$0/ton). For standards requiring a percent reduction in emissions, the incremental cost effectiveness of not providing an emission credit is \$274/Mg (\$250/ton) in Region V and \$1,111/Mg (\$1,000/ton) of SO_2 removed in Region VIII.

Table 10-9 summarizes the cost effectiveness of SO_2 control for fully-fired and supplementary-fired oil-fired combined cycle systems. For standards based on the use of low sulfur fuels, the average cost effectiveness of SO_2 control is \$705/Mg (\$640/ton) for a conventional steam generating unit, \$705/Mg (\$640/ton) for a fully-fired combined cycle steam generating unit without an emission credit, and \$502/Mg (\$455/ton) of SO_2 removed for a fully-fired combined cycle steam generating unit with an emission credit. For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of SO_2 control over standards based on the use of low sulfur fuels is \$48/Mg (\$44/ton) for a conventional steam generating unit, \$144/Mg (\$130/ton) for a fully-fired combined cycle steam generating unit without an emission credit, and \$691/Mg (\$628/ton) of SO_2 removed for a fully-fired combined cycle steam generating unit with an emission credit.

The cost effectiveness of SO_2 control is generally higher for supplementary-fired combined cycle steam generating units than for fully-fired combined cycle steam generating units, particularly in the case of standards requiring a percent reduction in SO_2 emissions, regardless of whether or not emission credits are provided. As shown in Table 10-9, for standards based on the use of low sulfur fuels the average cost effectiveness of SO_2 control is \$705/Mg (\$640/ton) for a supplementary-fired combined cycle steam generating unit without an emission credit, and \$0/Mg (\$0/ton) of SO_2 removed for a supplementary-fired steam generating unit with an emission credit. With an emission credit, the credit is so large that no emission reduction is required beyond the regulatory baseline. As a result, the cost effectiveness is \$0/Mg (\$0/ton) of SO_2 removed.

For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of SO_2 control over standards based on the use of low sulfur fuels is \$1,779/Mg (\$1,609/ton) for a supplementary-fired

TABLE 10-9. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR CONVENTIONAL AND COMBINED CYCLE OIL-FIRED STEAM GENERATING UNITS[a]

Steam Generating Unit	Fuel Type,[b] ng SO_2/J (lb SO_2/million Btu)	Annualized Costs[c], $1,000/yr	Annual Emissions, Mg/yr (tons/yr)	Average Cost Effectiveness,[d] $/Mg ($/ton)	Incremental Cost Effectiveness,[e] $/Mg ($/ton)
Conventional Unit, 29 MW (100 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	3,890	1,070 (1,180)	-	-
Low Sulfur Oil, 344 ng/J (0.8 lb/million Btu)	344 (0.8)	4,440	290 (320)	705 (640)	-
Percent Reduction (90 Percent)	1,291 (3.0)	4,450	82 (90)	567 (514)	48 (44)
Fully-Fired					
Combined Cycle Unit W/O Credit, 38 MW (129 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	3,890	1,070 (1,180)	-	-
Low Sulfur Oil, 344 ng/J (0.8 lb/million Btu)	344 (0.8)	4,440	290 (320)	705 (640)	-
Percent Reduction (90 Percent)	1,291 (3.0)	4,470	82 (90)	587 (532)	144 (130)
Combined Cycle Unit W/Credit, 38 MW (129 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	3,890	1,070 (1,180)	-	-
Low Sulfur Oil, 688 ng/J (1.6 lb/million Btu)[f]	688 (1.6)	4,140	572 (630)	502 (455)	-
Percent Reduction (87 Percent)[g]	1,291 (3.0)	4,460	109 (120)	593 (538)	691 (628)
Supplementary-Fired					
Combined Cycle Unit W/O Credit, 92 MW (313 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	3,890	1,070 (1,180)	-	-
Low Sulfur Oil, 344 ng/J (0.8 lb/million Btu)	344 (0.8)	4,440	290 (320)	705 (640)	-
Percent Reduction (90 Percent)	1,291 (3.0)	4,810	82 (90)	931 (844)	1,779 (1,609)
Combined Cycle Unit W/Credit, 92 MW (313 million Btu/hr)					
Regulatory Baseline, 1,291 ng/J (3.0 lb/million Btu)	1,291 (3.0)	3,890	1,070 (1,180)	-	-
Low Sulfur Oil, 1,291 ng/J (3.0 lb/million Btu)[h]	1,291 (3.0)	3,890	1,070 (1,180)	0 (0)	-
Percent Reduction (69 Percent)[i]	1,291 (3.0)	4,740	299 (330)	1,102 (1,000)	1,102 (1,000)

[a]Based on a capacity factor of 0.9.

[b]Average uncontrolled SO_2 emissions.

[c]Annual cost only includes cost of fuel fired plus annualized cost of SO_2 control device and does not include other steam generating unit operating and maintenance costs or annualized cost of the steam generating unit.

[d]Compared to regulatory baseline.

[e]Compared to low sulfur fuel alternative.

[f]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 129/100, or 29 percent. This would translate into an emission limit of 443 ng SO_2/J (1.03 lb SO_2/million Btu). Pricing data are not available, however, for an oil capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 100 percent in order to use available pricing data for an oil meeting a 688 ng SO_2/J (1.6 lb SO_2/million Btu) emission limit.

[g]Based on a 30 percent emission credit.

[h]Based on the heat input supplied by the gas turbine exhaust. Credit is calculated as 313/100, or 213 percent. This would translate into an emission limit of 1,076 ng SO_2/J (2.5 lb SO_2/million Btu). Pricing data are not available, however, for an oil capable of meeting this emission limit. Therefore, this analysis assumed an emission credit of 275 percent in order to use available pricing data for an oil meeting a 1,291 ng SO_2/J (3.0 lb SO_2/million Btu) emission limit.

[i]Based on a 210 percent emission credit.

steam generating unit without an emission credit, and \$1,102/Mg (\$1,000/ton) of SO_2 removed for a supplementary-fired steam generating unit with an emission credit.

As discussed earlier, in a supplementary-fired combined cycle steam generating unit the heat input of the gas turbine exhaust represents about 70 percent of the total heat input to the steam generating unit. Consequently, assuming the gas turbine fires natural gas, the gas turbine exhaust acts as a diluent, significantly increasing the volume of the flue gases from the steam generating unit without increasing the SO_2 emissions contained in these flue gases. In a fully-fired combined cycle system, the heat input of the gas turbine exhaust only represents about 30 percent of the total heat input to the steam generating unit and the diluent effect of the gas turbine exhaust is not as significant. Consequently, assuming the gas turbine fires natural gas, the cost effectiveness of SO_2 control is higher for supplementary-fired combined cycle steam generating units than for fully-fired combined cycle steam generating units.

If, however, the analysis assumed that oil was combusted in the gas turbine, rather than natural gas, the difference in the cost effectiveness of SO_2 control between supplementary-fired and fully-fired combined cycle steam generating units would narrow. If, for example, the analysis assumed oil of the same sulfur content was combusted in the gas turbine as in the steam generating unit (which probably represents a more realistic assumption) there would be no difference in the cost effectiveness of SO_2 control between supplementary-fired and fully-fired combined cycle steam generating units, other than that which might exist due to economies of scale.

Because the analysis kept the heat input from the fuel fired in the steam generating unit constant, the supplementary-fired steam generating unit is much larger than the fully-fired steam generating unit. As a result, under standards requiring a percent reduction in SO_2 emissions, the analysis would indicate that the cost effectiveness of SO_2 control is lower for a supplementary-fired combined cycle steam generating unit than for a fully-fired combined cycle steam generating unit due to economies of scale.

Table 10-10 summarizes the incremental cost effectiveness of SO_2 control associated with not providing emission credits for fully-fired and supplementary-fired combined cycle steam generating units firing oil. For standards based on the use of low sulfur fuels, the incremental cost effectiveness of SO_2 control is $1,064/Mg ($968/ton) for a fully-fired steam generating unit and $705/Mg ($640/ton) of SO_2 removed for a supplementary-fired steam generating unit. For standards requiring a percent reduction in SO_2 emissions, the incremental cost effectiveness of not providing emission credits is $370/Mg ($333/ton) for a fully-fired steam generating unit and $323/Mg ($292/ton) of SO_2 removed for a supplementary-fired steam generating unit.

10.2 MIXED FUEL-FIRED STEAM GENERATING UNITS

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. As a result, SO_2 emissions from mixed fuel-fired steam generating units are lower than SO_2 emissions from coal- or oil-fired steam generating units operating at the same heat input.

It has been suggested, therefore, that an emission credit should be included in new source performance standards for mixed fuel-fired steam generating units. Such an emission credit would permit higher SO_2 emission levels from mixed fuel-fired steam generating units by including the heat input supplied by the nonsulfur-bearing fuel in determining compliance with the standards. The magnitude of the credit would vary with the amount of heat input provided by the nonsulfur-bearing fuel.

As discussed above under "Consideration of Demonstrated Emission Control Technology Costs," to comply with a standard based on the use of low sulfur fuel, a fossil fuel-fired steam generating unit would be required to fire a low sulfur fuel or install an FGD system to reduce SO_2 emissions. Because of the dilution of the SO_2 emissions resulting from combustion of a fossil fuel with the gases resulting from combustion of a nonsulfur-bearing fuel, a mixed fuel-fired steam generating unit would not be required to fire

TABLE 10-10. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING EMISSION CREDITS FOR OIL-FIRED COMBINED CYCLE STEAM GENERATING UNITS

	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $/Mg ($/ton)
Fully-Fired			
Low Sulfur Oil			
With emission credit	4,140	572 (630)	-
Without emission credit	4,440	290 (320)	1,064 (968)
Percent Reduction			
With emission credit	4,460	109 (120)	-
Without emission credit	4,470	82 (90)	370 (333)
Supplementary-Fired			
Low Sulfur Oil			
With emission credit	3,890	1,070 (1,180)	-
Without emission credit	4,440	290 (320)	705 (640)
Percent Reduction			
With emission credit	4,740	299 (330)	-
Without emission credit	4,810	82 (90)	323 (292)

a low sulfur fuel or install an FGD system to reduce SO_2 emissions if an emission credit is provided.

If, for example, a standard based on the use of low sulfur fuels limited SO_2 emissions from coal combustion to 516 ng SO_2/J (1.2 lb SO_2/million Btu), a coal-fired steam generating unit would be required to fire a low sulfur coal or install an FGD system to reduce SO_2 emissions to this level. A mixed fuel-fired steam generating unit firing a 50/50 mixture of coal and a nonsulfur-bearing fuel on a heat input basis, however, would only have to fire a medium sulfur coal containing 1032 ng SO_2/J (2.4 lb SO_2/million Btu) or less to comply with this emission limit if an emission credit is provided for the heat input supplied by the nonsulfur-bearing fuel. Only if an emission credit is not provided for the heat input supplied by the nonsulfur-bearing fuel, would the mixed fuel-fired steam generating unit also be required to fire a low sulfur coal or install an FGD system to reduce SO_2 emissions.

A similar situation arises with a standard requiring a percent reduction in SO_2 emissions. A fossil fuel-fired steam generating unit would be required to achieve whatever specific percent reduction requirement is included in such a standard. With an emission credit, however, a mixed fuel-fired steam generating unit would not be required to achieve the specific percent reduction requirement, but would be permitted to achieve a lower percent reduction requirement.

If, for example, a standard included a requirement to achieve a 70 percent reduction in SO_2 emissions, a mixed fuel-fired steam generating unit firing a 50/50 mixture of coal and a nonsulfur-bearing fuel would only be required to achieve a 40 percent reduction in SO_2 emissions. If, on the other hand, a standard required a 90 percent reduction in SO_2 emissions, this mixed fuel-fired steam generating unit would only be required to achieve an 80 percent reduction in SO_2 emissions.

To assess the reasonableness of emission credits for mixed fuel-fired steam generating units, the cost effectiveness of SO_2 control for these units 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 mixed fuel-fired steam generating units was also examined.

The results of this analysis are summarized in Table 10-11 for mixed fuel-fired steam generating units firing coal and Table 10-12 for mixed fuel-fired steam generating units firing oil. In both cases, costs are presented only for a 44 MW (150 million Btu/hour) heat input capacity mixed fuel-fired steam generating unit firing a 20 percent coal or oil/80 percent nonsulfur-bearing fuel mixture. Larger mixed fuel-fired steam generating units were examined, as well as fuel mixtures with a higher percentage of coal or oil. This combination, however, results in the largest emission credit as well as the highest cost effectiveness of SO_2 control. Other cases involving either larger mixed fuel-fired steam generating units or a higher coal or oil 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 mixed fuel-fired units firing coal because, of the three regions examined where mixed fuel-fired steam generating units are expected to be constructed in significant numbers, the projected coal prices in Region X result in the highest cost effectiveness of SO_2 control.

As shown in Table 10-11, the average cost effectiveness of SO_2 control for standards based on the use of low sulfur coal is $1,098/Mg ($989/ton) for a mixed fuel-fired steam generating unit without an emission credit and $0/Mg ($0/ton) for a mixed fuel-fired steam generating unit with an emission credit. For a mixed fuel-fired steam generating unit with an emission credit, a coal with a sulfur content of 904 ng SO_2/J (2.10 lb SO_2/million Btu) is combusted under both the regulatory baseline and a standard based on the use of low sulfur coal. With an emission credit, therefore, a standard based on the use of low sulfur coal results in no emission reduction.

The average cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions is $2,568/Mg ($2,333/ton) for a mixed fuel-fired steam generating unit without an emission credit and $4,241/Mg ($3,895/ton) of SO_2 removed for the same unit with an emission credit.

TABLE 10-11. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING COAL

Steam Generating Unit/Regulatory Alternative	Fuel Type ng SO_2/J (lb SO_2/million Btu)	Annualized Costs $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Average Cost Effectiveness $/Mg ($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
Mixed Fuel-Fired Unit Without Credit (44 MW)[a]					
Regulatory Baseline - 1075 ng SO_2/J (2.5 lb SO_2/million Btu)[b]	904 (2.1)	3,587	151 (166)	-	-
Low Sulfur Fuel - 516 ng SO_2/J (1.2 lb SO_2/million Btu)	409 (0.95)	3,677	68 (75)	1,098 (989)	-
Percent Reduction - 90 percent	904 (2.1)	3,944	12 (13)	2,568 (2,333)	4,684 (4,306)
Mixed Fuel-Fired Unit With Credit (44 MW)[a]					
Regulatory Baseline - 1075 ng SO_2/J (2.5 lb SO_2/million Btu)[b]	904 (2.1)	3,587	151 (166)	-	-
Low Sulfur Fuel - 516 ng SO_2/J (1.2 lb SO_2/million Btu)	904 (2.1)	3,587	151 (166)	0(0)	-
Percent Reduction - 50 percent[c]	904 (2.1)	3,922	72 (80)	4,241 (3,895)	4,241 (3,895)

[a]Results are for a 44 MW (150 million Btu/hr) mixed fuel-fired steam generating unit firing an 80 percent nonsulfur-bearing fuel/20 percent coal mixture in Region X.

[b]Emission credits are allowed in the regulatory baseline, reflecting existing standards and practice.

[c]For this fuel mixture, only 50 percent SO_2 reduction is required with an emission credit to meet a 90 percent reduction requirement.

TABLE 10-12. COST AND COST EFFECTIVENESS OF SO_2 CONTROL FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING OIL

Steam Generating Unit/Regulatory Alternative	Fuel Type ng SO_2/J (lb SO_2/million Btu)	Annualized Costs $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Average Cost Effectiveness $/Mg ($/ton)	Incremental Cost Effectiveness $/Mg ($/ton)
Mixed Fuel-Fired Unit Without Emission Credit (44 MW)[a]					
Regulatory Baseline - 1290 ng SO_2/J (3.0 lb SO_2/million Btu)[b]	1,290 (3.0)	3,713	215 (237)	-	-
Low Sulfur Fuel - 344 ng SO_2/J (0.8 lb SO_2/million Btu)	344 (0.8)	3,821	57 (63)	684 (621)	-
Percent Reduction - 90 percent	1,290 (3.0)	4,041	17 (19)	1,657 (1,505)	5,500 (5,000)
Mixed Fuel-Fired Unit With Emission Credit (44 MW)[a]					
Regulatory Baseline - 1290 ng SO_2/J (3.0 lb SO_2/million Btu)[b]	1,290 (3.0)	3,713	215 (237)	-	-
Low Sulfur Fuel - 344 ng SO_2/J (0.8 lb SO_2/million Btu)	1,290 (3.0)	3,713	215 (237)	0 (0)	-
Percent Reduction - 50 percent[c]	1,290 (3.0)	4,002	103 (114)	2,580 (2,350)	2,580 (2,350)

[a]Results are for a 44 MW (150 million Btu/hr) mixed fuel-fired steam generating unit firing an 80 percent nonsulfur-bearing fuel/20 percent oil mixture in Region I.

[b]Emission credits are allowed in the regulatory baseline, reflecting existing standards and practice.

[c]For this fuel mixture, only 50 percent SO_2 reduction is required with an emission credit to meet a 90 percent reduction requirement.

The incremental cost effectiveness of SO_2 emission control associated with standards requiring a percent reduction in emissions over standards based on the use of low sulfur coal is \$4,684/Mg (\$4,306/ton) for a mixed fuel-fired steam generating unit without an emission credit and \$4,241/Mg (\$3,895/ton) of SO_2 removed for a mixed fuel-fired steam generating unit with an emission credit. As shown in Table 10-13, the incremental cost effectiveness of not providing emission credits for mixed fuel-fired steam generating units under a standard based on the use of low sulfur coal is \$1,084/Mg (\$989/ton) of SO_2 removed. Similarly, the incremental cost effectiveness of not providing emission credits under a standard requiring a percent reduction in emissions is \$367/Mg (\$328/ton) of SO_2 removed.

Table 10-12 summarizes the cost effectiveness of SO_2 control for mixed fuel-fired steam generating units firing oil as the fossil fuel. Mixed fuel-fired steam generating units were only examined for Region I because the sulfur premium for low sulfur oil compared to a high sulfur oil is essentially constant for all regions. For a standard based on the use of low sulfur oil, the average cost effectiveness of SO_2 control for a mixed fuel-fired steam generating unit without an emission credit is \$684/Mg (\$621/ton) compared to \$0/Mg (\$0/ton) of SO_2 removed for the same unit with an emission credit. As in the analysis discussed above for mixed fuel-fired steam generating units firing coal, including an emission credit in a standard based on the use of low sulfur fuel results in no emission reduction. With an emission credit, a high sulfur oil is fired under both the regulatory baseline and a standard based on the use of low sulfur oil.

The average cost effectiveness of SO_2 control for standards requiring a percent reduction in emissions is \$1,657/Mg (\$1,505/ton) for a mixed fuel-fired steam generating unit without an emission credit and \$2,580/Mg (\$2,350/ton) of SO_2 removed for the same unit with an emission credit.

The incremental cost effectiveness of SO_2 emission control associated with standards requiring a percent reduction in emissions over standards based on the use of low sulfur oil is \$5,500/Mg (\$5,000/ton) for a mixed fuel-fired steam generating unit without an emission credit and \$2,580/Mg (\$2,350/ton) of SO_2 removed for a mixed fuel-fired steam generating unit

TABLE 10-13. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING EMISSION CREDITS FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING COAL[a]

	Annualized Cost $1,000/yr	Annual Emissions Mg/yr (tons/yr)	Incremental Cost Effectiveness $/Mg ($/ton)
Low Sulfur Coal			
With Emission Credit	3,587	151 (166)	-
Without Emission Credit	3,677	68 (75)	1,084 (989)
Percent Reduction			
With Emission Credit	3,922	72 (80)	-
Without Emission Credit	3,944	12 (13)	367 (328)

[a]For a 44 MW (150 million Btu/hr) heat input capacity mixed fuel-fired steam generating unit firing a 20 percent coal/80 percent nonsulfur-bearing fuel mixture in Region X.

with an emission credit. An emission credit, therefore, appears to reduce substantially the incremental cost effectiveness of a standard requiring a percent reduction in SO_2 emissions. This is not really the case, however. This substantially lower incremental cost effectiveness is the result of including an emission credit in a standard based on the use of low sulfur oils, not in a standard requiring a percent reduction in SO_2 emissions.

As mentioned above, with an emissions credit, a standard based on the use of low sulfur oils results in no SO_2 emission reduction. Thus, regardless of whether a standard requiring a percent reduction in SO_2 emissions includes an emissions credit or not, when compared to this alternative the large incremental reduction in SO_2 emissions achieved by any standard requiring a percent reduction in emissions results in a substantially lower incremental cost effectiveness.

If, for example, the alternative of a standard requiring a percent reduction in SO_2 emissions without an emission credit is compared to the alternative of a standard based on the use of low sulfur oil with an emission credit, the resulting incremental cost effectiveness of SO_2 control is $1,657/Mg ($1,505/ton) of SO_2 removed. This is lower than the incremental cost effectiveness of $2,580/Mg ($2,350/ton) of SO_2 removed cited above and shown in Table 10-12 for a standard requiring a percent reduction in SO_2 emissions with an emission credit. Thus, the substantially lower incremental cost effectiveness which may appear to be the result of including an emission credit in a standard requiring a percent reduction in SO_2 emissions is not the result of including an emission credit, but the result of comparing this alternative to a standard based on the use of low sulfur oil with an emission credit.

As shown in Table 10-14, the incremental cost effectiveness of not providing emission credits is $684/Mg ($621/ton) for standards based on the use of low sulfur oil and $453/Mg ($411/ton) of SO_2 removed for standards requiring a percent reduction in SO_2 emissions.

TABLE 10-14. INCREMENTAL COST EFFECTIVENESS OF NOT PROVIDING EMISSION CREDITS FOR MIXED FUEL-FIRED STEAM GENERATING UNITS FIRING OIL[a]

	Annualized Cost $1,000/yr	Annual Emissions (tons/yr)	Incremental Cost Effectiveness ($/ton)
Low Sulfur Oil			
With Emission Credit	3,713	215 (237)	-
Without Emission Credit	3,821	57 (63)	684 (621)
Percent Reduction			
With Emission Credit	4,002	103 (114)	-
Without Emission Credit	4,041	17 (19)	453 (411)

[a]For a 44 MW (150 million Btu/hr) heat input capacity mixed fuel-fired steam generating unit firing a 20 percent oil/80 percent nonsulfur-bearing fuel mixture in Region I.

TECHNICAL REPORT DATA

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15. SUPPLEMENTARY NOTES

16. ABSTRACT

This document summarizes the environmental, economic, and cost analyses that were conducted to support the development of new source performance standards limiting emissions of SO_2 from industrial-commercial-institutional steam generating units. Alternative SO_2 control technologies and regulatory options are analyzed in terms of SO_2 emission reduction capability, costs of control, secondary environmental impacts, national impacts, and industry-specific economic impacts. In addition, the impacts of allowing emission credits for cogeneration and mixed fuel-fired steam generating units are discussed. This document is intended to serve as an overview of the analyses and regulatory alternatives considered during the standards development process.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS	b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
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