regulatory baseline cost of $5.8 million per year. For a wood-fired steam generating unit, this represents a 4.9 to 7.7 percent increase in annualized cost over a regulatory baseline cost of $3.4 to $5.4 million per year depending on the economic value of wood waste ($/million Btu).

To comply with standards based on Technical Aternative II, a 44 MW (150 million Btu/hour) heat input capacity coal-fired spreader stoker steam generating unit would incur increased annualized costs of $283.000 per year, which is an increase of 4.9 percent over the regulatory baseline. A 44 MW (150 million Btu/hour) heat input capacity wood-fired steam generating unit would incur increased annualized costs of $318,000 per year, which is an increase of 5.9 to 9.3 percent over the regulatory baseline, depending on the wood fuel value assumed.

The precentage increases in both capital and annualized costs cited above for Technical Alternative I and Technical Alternative II are relatively constant with respect to variations in steam generating unit size. Thus, the percentage increases presented above are representative of the range of steam generating unit sizes covered by the proposed particulate matter standards.

Even though the percentage increases in capital and annualized costs remain relatively constant for all steam generating unit sizes, the incremental cost-effectiveness of applying the demonstrated particulate matter control technologies to different size steam generating units varies significantly with steam generating unit size. This variance occurs because uncontrolled particulate matter emissons vary linearly with steam generator size for a given steam generator while the costs of particulate matter control do not. In addition, the cost-effectiveness of particulate matter control is influenced by the different steam generator designs representative of different size steam generating units.

In the range of 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity, spreader stoker systems represents the predominant design for the combustion of solid fuel, although some mass-feed units may be present. Above 73 MW (250 million Btu/hour) heat input capacity, pulverized coal-fired steam generating units represent the predominate design for coal firing, although wood-fired steam generating units continue to utilize the spreader stoker design. With increasing steam generating unit size, the increased fuel consumption rate and fuel costs justify the use of more complicated, more expensive, and more efficient steam generator designs.

Due to the unique characteristics of each of these steam generator designs, particulate matter emissions differ, with the emissions from spreader stoker steam generating units being inherently lower than those from pulverized coal-fired steam generating units. Because the cost-effectiveness of air pollution control systems is measured in terms of the cost ($) per Mg (ton) of pollutant removed, the inherently different baseline emission characteristics of each of these steam generator designs lead to significant differences in the cost-effectiveness of particulate matter emission control.

The cost-effectiveness of particulate matter controls for various coal-fired steam generating units is given in Table 5 for each technical alternative. Table 5 also compares the relative cost-effectiveness for Technical Alternative I and Technical Alternative II. Except for steam generating units with heat input capacities greater than 73 MW (250 million Btu/hour), the cost per Mg (ton) of particulate matter removed is generally lower for the less effective and less costly control systems associated with Technical Alternative I. For pulverized coal-fired steam generating units, which are characteristic of steam generating units above 73 MW (250 million Btu/hour) heat input capacity, sidestream separators are not demonstrated. For this reason, Technical Alternative I assumes the use of an ESP which is comparable in cost to a fabric filter. As a result, the cost effectiveness of Technical Alternative I and Technical Alternative II is essentially the same for this size range above 73 MW (250 million Btu/hour) heat input capacity.

TABLE 5.—INCREMENTAL COST-EFFECTIVENESS OF PARTICULATE MATTER CONTROLS ON COAL-FIRED STEAM GENERATING UNITS

Steam generator size MW (million Btu/hr) heat input capacity	Steam generator type	Technical alternative I (lower level of control)		Technical alternative II (higher level of control)	
		Cost-effectiveness		Cost-effectiveness	
		Dollars per million removed	Dollars per ton removed	Dollars per million removed	Dollars per ton removed
29 (100)	Spreader stoker	630	(570)	1,542	(1,400)
44 (150)	Spreader stoker	560	(510)	1,400	(1,300)
73 (250)	Spreader stoker	520	(470)	1,300	(1,200)
73 (250)	Pulverized coal-fired	750	(680)	740	(670)
117 (400)	Pulverized coal-fired	580	(530)	660	(600)

E. Selection of Regulatory Alternatives

The technology and cost considerations discussed above lead to two principal regulatory alternatives which could serve as the basis for standards of performance to limit particulate matter and NO_x emissions from industrial-commercial-institutional steam generating units.

The consideration of regulatory alternatives focused on the 29 to 73 MW (100 to 250 million Btu/hour) heat input capacity size range. This size range represents the "heart" of the coal-fired industrial-commercial-institutional steam generating unit population.

To illustrate clearly the differences between the regulatory alternatives which could be selected as the basis of the proposed standards of performance for industrial-commercial-institutional steam generating units, two specific regulatory alternatives were analyzed in depth for their environmental, energy, and economic impacts. The principal difference between these two alternatives is the technical basis selected for standards of performance limiting emissions of particulate matter from steam generating units between 29 MW (100 million Btu/hour) and 73 MW (250 million Btu/hour) heat input capacity. Regulatory Alternative A is the lower cost alternative and the standards limiting particulate matter emissions for steam generating units in this size range would be based primarily on Technical Alternative I (i.e., use of sidestream separators, low efficiency ESP's or low pressure drop wet scrubbers). Regulatory Alternative B is the higher cost alternative and the standards limiting particulate matter emissions from steam generating units between 29 MW (100 million Btu/hour) and 73 MW (250 million Btu/hour) heat input capacity would be based primarily on Technical Alternative II (i.e., use of fabric filters, high efficiency ESP's or high pressure drop scrubbers). In both regulatory alternatives, the standards for particulate matter would be based on Technical Alternative II for steam generating units of greater than 73 MW (250 million Btu/hour) heat unit capacity.

In addition to the variations in the cost-effectiveness of emission control with steam generating unit size and steam generating unit type that were discussed earlier, the cost-effectiveness of emission control also varies with steam generating unit operating level. Some steam generating units are operated near full capacity while others are operated at low capacity. Higher fixed costs for emission control systems can lead to higher costs per Mg (ton) of pollutant removed for steam generating units with relatively low levels of operation.

For particulate matter control, some steam generating units may fire mixtures of fuels which contain only small amounts of fuels which generate particulate matter emissions, such as coal, wood, or solid waste, with fuels, such as natural gas or distilate oil, which do not generate significant particulate matter emissions. In each of these cases, the cost-effectiveness of emission control will vary. The cost-effectiveness of emission control on steam generating units operated near full capacity is more attractive than on steam generating units operated at low capacity. Similarly, the cost-effectiveness of particulate matter on steam generating units which fire substantial amounts of fuels which generate significant uncontrolled particulate matter emissions is more attractive than on steam generating units which only cofire limited amounts of these fuels with other fuels.

Steam generating unit use is generally expressed in terms of an annual capacity factor. This factor represents the amount of fuel actually fired in relation to the amount of fuel the steam generating unit is capable of firing on an annual basis. The overall average industrial-commercial-institutional steam generating unit annual capacity factor is about 60 percent (0.60). This average annual capacity factor was employed to estimate all the annualized costs and cost-effectiveness values included in the cost analysis discussion presented above.

Steam generating units which operate at less than 60 percent annual capacity factor will experience less favorable cost-effectiveness levels; steam generating units which operate above 60 percent annual capacity factor will experience improved cost-effectiveness levels. Steam generating unit operation at a 30 percent (0.30) annual capacity factor would approximately double the annualized cost per Mg (ton) of pollutant removed compared to unit operation at a 60 percent annual capacity factor. Additionally, the same doubling effect would occur in cases where an equal mix of a fuel that does not generate significant uncontrolled particulate matter emissions (natural gas) is fired with a fuel that does generate a significant uncontrolled particulate matter emissions (wood). That is, a steam generating unit was firing a fuel mixture of 50 percent natural gas and 50 percent coal and operated at an overall annual capacity factor of 60 percent based on total heat input, the "effective" capacity factor of this steam generating unit would appear to be 30 percent when considering only those fuels that generate significant uncontrolled particulate matter emissions.

Given the difference in cost-effectiveness of particulate matter control between steam generating units which operate at low annual capacity factors compared to steam generating units which operate at high annual capacity factors, regulatory alternatives have been developed which would provide special consideration for low capacity steam generating units between 29 and 73 MW (100 and 250 million Btu/hour) heat input capacity. Under both regulatory alternatives analyzed, coal-, wood- solid waste-, and mixed fuel-fired steam generating units in this size range with an annual capacity factor of 30 percent or less would be subject to a less restrictive particulate matter emission limit. For Alternative A (the less stringent alternative), the alternative standard would be 129 ng/J (0.30 lb/million Btu) heat input, and for Alternative B (the more stringent alternative) would be of 86 ng/J (0.20 lb/million Btu) heat input. The 130 ng/J (0.30 lb/million Btu) heat input level would be based on the use of double mechanical collectors, low efficiency ESP's, or low pressure drop wet scrubbers to control particulate matter emissions. The 86 ng/J (0.20 lb/million Btu) heat input limit is based on the use of sidestream separators, low efficiency ESP's, or low pressure drop wet scrubbers to control particulate matter emissions.

The NO_x emissions limits are the same under both Regulatory Alternative A and Regulatory Alternative B. For residual oil and for coal-fired steam generating units, there is only one NO_x emission control technology which is demonstrated for each boiler type. For natural gas- and distillate coal-fired units, two technical alternatives are available in LEA alone or LEA/SC. LEA/SC technology however, would achieve significantly greater emission reductions compared to LEA alone at no significantly greater cost. Therefore, the environmental, energy, and economic impacts of only one NO_x regulatory alternative (based on LEA/SC technology) were analyzed.

The proposed standards for NO_x would be 301 ng/J (0.70 lb/million Btu) heat input for pulverized coal-fired steam generating units, based on the use of LEA/SC alone; to reduce emissions; 258 ng/J (0.60 lb/million Btu) heat input for spreader stoker coal-fired steam generating units, based on the use of low excess air (LEA); and 215 ng/J (0.5 lb/million Btu), for mass-feed stoker coal-fired steam generating units, based on the use of LEA alone.

The proposed NO_x standards for distillate oil- and natural gas-fired steam generating units would be 43 ng/J (0.10 lb/million Btu) heat input. The distillate oil and natural gas standards are based on the use of LEA/SC. The use of SCB technology would be expected for most package natural gas and distillate-fired steam generating units. The NO_x control standards for residual oils vary according to fuel nitrogen content. For low nitrogen residual oils (nitrogen content less than or equal to 0.35 weight percent), the standard would be 129 mg/J (0.30 lb/ million Btu) heat input, and for high nitrogen residual oils (nitrogen content greater than 0.35 weight percent), the standard would be 172 ng/J (0.40 lb/million Btu) heat input. The standards for low nitrogen and high nitrogen residual oils would be based on the use of LEA/SC.

NO_x standards would also apply to steam generating units firing mixtures of fossil fuels and wood, solid waste, or byproducts/wasted. Mixtures of wood, solid waste, or byproducts/wastes. Mixtures of wood, solid waste, and fossil fuel would be subject to NO_x emission limits if the heat input from the combustion of fossil fuel would exceed 5 percent on an annual basis. Mixtures of byproducts/wastes and fossil fuel would be subject to an NO_x emission limit determined through the use of a prorating formula. For the purpose of prorating, gaseous byproducts/wastes would be subject to the same NO_x emission limits as natural gas, and liquid byproducts/wastes would be subject to the same NO_x emission limits as residual oils, depending on their fuel nitrogen characteristics.

As with the control of particulate matter emissions, the cost-effectiveness of NO_x emissions control varies with steam generating unit operation. Some steam generating units operate at high capacity, while others operate of low capacity. The cost-effectiveness of emission control is less attractive for steam generating units operating at low capacities than for those operating at high capacities. Similarly, the cost-effectiveness of NO_x control (including emissions monitoring) is more attractive for steam generators which cofire substantial amounts of fossil fuels than for steam generators which cofire limited amounts of fossil fuels in fossil-nonfossil fuel mixtures because of the higher uncontrolled emissions from the combustion of fossil fuels.

As discussed above, an average annual capacity factor of 60 percent was employed to estimate all the annualized costs and cost-effectiveness values included in the cost analysis discussed earlier. Steam generating units which operate with annual capacity factors above 60 percent would experience more attractive cost-effectiveness values than those discussed, and steam generating units which operate with annual capacity factors below 60 percent would experience less attractive cost effectiveness values. Operation at a capacity factor of 30 percent would approximately double the cost per ton of emission control compared to operation at an annual capacity factor of 60 percent.

Given the difference in the cost-effectiveness of NO_x emission control between steam generating units which operate at low annual capacity factors compared to those that operate at high annual capacity factors because of continuous NO_x monitoring costs, both regulatory alternatives would exempt units which operate at low annual capacity factors from the requirement to install and operate continuous NO_x monitors. Instead, steam generating units emissions which operate at an annual capacity factor of 30 percent or less based on fossil fuel consumption would be required to monitor various operating conditions in lieu of NO_x emissions monitoring. To monitor operating conditions rather than NO_x emissions, a plan would be submitted for approval outlining what conditions would be monitored and what records of these conditions would be maintained. The NO_x monitoring requirements for low capacity units is discussed further below in the *Performance Test Methods and Monitoring Requirement* section.

1. Consideration of Economic Impacts

Introduction. A detailed analysis was undertaken to assess the potential economic impacts associated with standards based on Regulatory Alternative B. This alternative is more stringent than Regulatory Alternative A. Consequently, while no analysis was undertaken to assess the potential economic impacts of standards based on Regulatory Alternative A, the impacts based on Alternative A would be less than those discussed below for standard based on Regulatory Alternative B.

Fossil Fuel Steam Generating Units. Because 700 fossil fuel-fired steam generating units could potentially be affected by the proposed standard, the economic impacts of standards based on Regulatory Alternative B on fossil fuel-fired steam generating units 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 industrywide averages for eight large industry groups. The goups selected for analysis account for approximately 70 percent of the total industrial steam consumption. These eight industry groups were: Food; textiles; paper; chemicals; petroleum refining; stone, clay, and glass; stee; and aluminum.

To determine the potential product price impacts of standards based on Regulatory Alternative B, 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 standards based on Regulatory Alternative B were estimated based on annualized steam generating unit and pollution control costs. Assuming "full cost pass-through" of these increased costs to products prices, the potential impact of standards based on this regulatory alternative on product prices was estimated.

Growth projections indicate that about 1 to 9 percent of the steam consumption in the eight major steam-using industries would be generated in steam generating units subject to the proposed standards by 1990. The lowest percentage is projected for the paper industry with one percent being steam from affected facilities. The highest percentage is projected for the chemical industry with 9 percent being steam from affected facilities.

The analysis indicates that average steam costs in these industry groups would increase from about \$9.43 to \$9.54/GJ (\$8.94 to \$9.04/million Btu) of heat input, an increase of about 1 percent based on industrywide average annualized costs. Assuming "full cost pass-through" of increased steam costs, product prices in the major industry group would increase by less than 0.1 percent. This potential impact represents a maximum product price increase because of the "full cost pass-through" assumption with no cost adsorption. 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 of the potential economic impacts of standards based on Regulatory Alternative B focused on the selected industries which were considered likely to be most affected by proposed standards. Seven industries were selected due to the steam-intensive nature of their operation, the low utilization of their steam generating unit capacity, or their comparatively small industry size. 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, 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 standards based on Regulatory Alternative B as the result of new steam generating unit construction were calculated.

Assuming "full cost pass-through" of steam cost increases, the potential impact of standards based on Regulatory Alternative B on product prices 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 100 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 by 0.001 to 0.15 percent in 1988, assuming "full cost pass-through" of increased steam costs. The lowest increase was projected for the automobile manufacturing industry based on an assumption that one of four existing coal-fired steam generating units at the model plant would be replaced by a coal-fired steam generating unit subject to standards based on Regulatory Alternative B. The highest percentage increase was exhibited by the beet sugar refining industry based on an assumption that three of four existing oil-fired steam generating units at the model plant would be replaced by a new coal-fired steam generating units subject to standards based on Regulatory Alternative B.

Based on the same scenarios as above, but assuming "full cost absorption" of increased steam costs, return on assets was projected to decrease by less than 0.01 to 0.51 percentage points as a result of standards based on Regulatory Alternative B. Again, these potential impacts represent "worst 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 standards based on Regulatory Alternative B 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 standards based on Regulatory Alternative B on each model firm's cash flow coverage ratio and debt/equity ratio under each of five debt/equity financing strategies was estimated based on the amount of financing needed to construct replacement or expansion steam generating units envisioned under the same scenarios used in the price and profitability analysis.

Cash flow coverage ratios and book debt/equity ratios showed essentially no change for any of the model firms under any of the five different debt/equity financing strategies. Consequently, standards based on this regulatory alternative would not impair the ability of firms to raise sufficient capital to construct fossil fuel-fired steam generating units.

Nonfossil Fuel-Fired Steam Generating Units. The economic impact analysis of standards based on Regulatory Alternative B for nonfossil fuel-fired steam generating units was essentially the same as that for the second phase of the analysis for fossil fuel-fired steam generating units. The principal difference is that the analysis for nonfossil fuel-fired steam generating units examined potential impacts on both model plants/model firms and municipalities. A number of municipalities are expected to construct solid waste-fired steam generating units in the future which would be covered by the proposed standards.

The industries selected for analysis reflected the major industry users of nonfossil fuel-generated steam. The four industries examined were: Wood furniture manufacturing, sawmill lumber products, plywood panel products, and paper and allied products manufacturing. Each of the industries selected presently burns nonfossil fuels for part or all of its steam requirements.

Based on various scenarios involving replacement of 25 to 75 percent of existing steam generating unit capacity at the model plants developed for each of the industries and assuming "full cost pass-through" of increased steam costs, product prices were estimated to increase by less than 0.5 percent in all cases. Based on an assumption of "full cost absorption," return on assets was estimated to decrease by 0.02 to 0.30 percentage points. Again, these estimates of potential impacts on product prices and return on assets represent "worst case" estimates because of the assumptions of "full cost pass-through" and "full cost absorption."

Based on model firms developed for each industry, incorporating the same model plant and steam generating unit construction scenarios, cash flow coverage ratios and book debt/equity ratios showed essentially no change under any of five different debt/equity financing strategies. Thus, standards based on Regulatory Alternative B would not impair the ability of firms to raise sufficient capital to construct nonfossil fuel-fired steam generating units.

Four municipalities representing different economic and steam generating unit ownership situations were selected for analysis. Municipalities were selected to represent the following categories: Publicly owned steam generating units in economically distressed cities financed by State funds; publicly owned steam generating units in economically distressed cities financed by municipal funds; publicly owned steam generating units in economically stable cities; and privately owned and operated steam generating units.

For the municipalities, the economic impact analysis focused on the increase in the cost of steam and on capital availability to finance the incremental costs imposed by standards based on Regulatory Alternative B. The increase in the average steam costs resulting from compliance with standards based on this alternative was estimated and compared to steam costs in the absence of such standards to determine if the increase would be significant. The incremental increase in capital requirements to finance new steam generating unit construction was also estimated and compared to capital requirements in the absence of such standards to determine if the increase was likely to cause deferral of the project or a change in the method of financing.

The analysis indicated little if any impact on municipal solid wastefired steam generating unit construction. Capital requirements would generally increase by about 0.3 percent and average steam costs would increase by about 1 percent. Neither of these increases is considered substantial, and the increased capital requirements would not result in a deferral of the project or a change in current methods of financing.

Conclusions. The economic impacts analysis indicates that standards based on Regulatory Alternative B would increase product prices by substantially 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 decrease by substantially less than 1 percent for all firms. Cash flow coverage and book debt/equity ratios showed essentially no change as a result of standards based on this regulatory alternative. Therefore, standards based on this alternative would not impose any capital availabilty constraints on firms. Ffor municipalitfies, construction of solid waste-fired boilers would not be deferred or would not require different forms of financing due to standards based on Regulatory Alternative B.

As mentioned earlier, Regulatory Alternative B is more stringent than Regulatory Alternative A. Consequently, the economic impacts of standards based on Regulatory Alternative A would be less severe than those based on Regulatory Alternative B.

2. Consideration of National Impacts

The potential incremental national impacts associated with standards based on each regulatory alternative were analyzed. The analysis examined the potential incremental national environmental, energy, and cost impacts of these alternatives in the fifth year following proposal of standards. National enviornmental impacts were examined by projecting air pollutant emissions and the level of solid and liquid waste products that would be generated under the regulatory baseline and under each regulatory alternative. In the case of particulate matter, the national impact of standards based on each regulatory alternative was examined in terms of both total mass emissions and inhalable particulate matter emissions (less than 10 microns diameter).

National incremental energy impacts were examined from two viewpoints. The first viewpoint was the potential impact of standards on coal use in new industrial-commercial-institutional steam generating units. This impact was estimated by projecting national coal demand for new units under the regulatory baseline and then under each regulatory alternative. The relative demand for coal versus that for natural gas and oil was then examined. The second viewpoint was the potential impact of standards on the national energy consumption of new steam generating unit pollution control systems. This impact was estimated by projecting the national electrical energy consumption of the pollution control equipment required for compliance under the regulatory baseline and then under each regulatory alternative.

The analysis of incremental national cost impact examined the potential impact of standards on the national capital and annualized costs for new steam generating units. These impacts were estimated by projecting the total national capital and annualized costs associated with installation and operation of the pollution control equipment required for compliance under the regulatory baseline and then under each regulatory alternative.

National impacts were analyzed for industrial steam generating units firing fossil fuel (coal, oil, and natural gas) through the use of a computer model, referred to as the Industrial Fuel Choic Analysis Model (IFCAM). IFCAM simulates fuel choice decisions at the steam generator level based ont he after-tax present value of the cost of generating steam over a 15-year investment period. The model selects the fuel/steam generator/emission control system combination with the lowest after-tax present value which is capable of complying with the applicable emission standard.

Because the assumptions used in the analysis to represent economic conditions in future years have a significant effect on the results obtained from IFCAM, national impacts were analyzed for two different economic scenarios. Table 6 presents the assumptions used under each scenario.

TABLE 6.—ASSUMPTIONS EMPLOYED IN IFCAM NATIONAL IMPACTS ANALYSIS FOR FOSSIL FUEL-FIRED INDUSTRIAL STEAM GENERATING UNITS

	Energy Scenario I (lower natural gas price)	Energy Scenario II (higher natural gas price)
Regulatory baseline.	State implementation plant (SIP) emission limits and existing New Source Performance Standards (NSPS)	State implementation plan (SIP) emission limits and existing New Source Performance Standards (NSPS).
Natural gas prices (1982 $/million Btu).	1985: 4.27 1990: 5.15 1995: 5.41	1985: 5.62. 1990: 7.23. 1995: 7.60.
Oil prices (1982 $/bbl).	1985: 25.90 1990: 31.90 1995: 46.50	1985: 25.90. 1990: 31.90. 1995: 46.50.
New boiler projections at baseline (number of units).	100 Coal 580 Oil/NG	415 Coal. 275 Oil/NG.

The effect of energy-related legislation is simulated in IFCAM by including provisions of various laws or proposed legislation relevant to steam generating unit fuel choice. Energy Scenarios I and II both include provisions of the Energy Tax Act of 1978 (ETA) and the Economic Recovery Tax Act of 1981 (ERTA). The ETA provides tax incentives for the use of coal and alternative fuels, and the ERTA revises the depreciation schedules for capital investment. Energy Scenario I reflects natural gas prices lower than, but which tend to track, the price of medium sulfur residual oil. Alternatively, the natural gas prices used in Energy Scenario II are higher than the price of distillate oil in most regions. The two energy scenarios reflect differing assumptions regarding contract re-negotiations between natural gas producers and pipeline companies.

The mix of fossil fuels selected by IFCAM, in conjunction with the requirements of alternative standards, determines the national incremental emission reduction as well as the national incremental cost impacts associated with standards. Under Energy Scenario II, (i.e., high natural gas prices relative to coal and oil) about 70 percent of the fossil fuel demand for new steam generating units is projected to be met by coal. Under Energy Scenario I, (i.e., low natural gas prices relative to coal and oil) only about 20 percent of the total fossil fuel demand is projected to be met by coal. Consequently, the national impacts under Scenario II will be much greater than those under Scenario I, both in terms of emissions reductions and in terms of costs. Because it is impossible to predict with certainty the economic and regulatory conditions of the future, the national impacts associated with both Scenario I and Scenario II are discussed below. The "real" national impacts most likely fall somewhere within the range predicted by the two scenarios.

The regulatory baseline in IFCAM consists of State implementation plan (SIP) requirements and the existing standards of performance applicable to large fossil fuel-fired steam generating units (i.e., Subpart D of 40 CFR Part 60). This means that in the absence of the proposed standards, new steam generating units with heat input capacities of 73 MW (250 million Btu/hour) or less are assumed to meet general SIP requirements. The national cost impacts projected to result from the proposed standards for these units are measured from the SIP baseline and, to the extent that new steam generating units would apply emission control technology which are more efficient (and more expensive) than required by SIP's, the national cost impacts projected by IFCAM may be overstated.

Other baseline control levels could be used for national impact analyses. For example, site-specific emission control requirements for new steam generating units as determined through prevention of significant deterioration (PSD) and new source review (NSR) regulations could be used to define a baseline control level for new units. Based on an initial review of the data available for recent PSD and NSR permits for non-utility coal-fired steam generating units, many units are being required to install emission control technology as stringent, or more stringent, than the proposed standards. A baseline control level based upon PSD and NSR requirements would reduce the projected national impacts of the proposed standards. In cases where site-specific PSD and NSR permit requirements are as stringent, or more stringent, than the proposed standards, negligible environmental, energy, and economic impacts would result from the proposed standards.

Although various baseline assumptions can be used to estimate national impacts that would result from the proposed standards, it is most appropriate to assume a SIP baseline control level for units with a heat input capacity of 73 MW (250 million Btu/hour) or less. The SIP baseline represents minimal requirements and thus will tend to estimate the total cost of air pollution control being experienced. In addition, since PSD and NSR permits are site-specific, they do not provide as clear a definition of the baseline as existing State regulations for new steam generating units at other sites.

New industrial steam generating unit demand in IFCAM is a function of growth in industrial fossil fuel demand and replacement of existing capacity. The former depends on the projected growth in industry adjusted for projected conservation and projected switching by industry to increased use of nonfossil fuels and electricity. The latter depends on the projected retirement rate of existing capacity. IFCAM uses both historical steam generating unit population data and recent sales data to estimate the size distribution of new steam generators. Based on IFCAM predictions, a total of about 700 new fossil fuel-fired industrial steam generating units of more than 29 MW (100 million Btu/hour) heat input capacity are projected to initiate operation between 1983 and 1988.

For nonfossil fuel-fired steam generating units, national impacts were assessed through the use of model units of various sizes. Growth in nonfossil fuel-fired industrial steam generating unit capacity, in terms of both the number and the size distribution of these units, is based on historical sales data and industry and vendor projections for sales of new wood- and municipal-type solid waste-fired steam generators. A total of about 120 new wood- and municipal-type solid waste-fire steam generating units of more the 29 MW (100 million Btu/hour) heat input capacity are projected to be built by 1988.

Annualized costs of generating steam were calculated over a 15-year investment period. In addition, nonfossil fuels were assumed to represent waste fuels having no economic value. A cost credit was also included for burning municipal-type solid waste to reflect savings achieved by avoiding the cost of landfilling.

Unlike IFCAM, the national impacts analysis for nonfossil fuel-fired steam generating units is not affected by energy-related legislation. The regulatory baseline for nonfossil fuel-fired units is based on SIP requirements. As discussed previously, using SIP requirements as the regulatory baseline may tend to overstate the impacts presented here.

The total national impacts analysis projects that about 810 new fossil and nonfossil fuel fired industrial-commercial-institutional steam generating units having heat input capacities of greater than 29 MW (100 million Btu/hour) will be constructed over the next 5 years under the regulatory baseline. Under Energy Scenario I (i.e., low natural gas prices), this projected total would consist of about 580 natural gas- and oil-fired units, about 100 coal-fired units, about 80 wood-fired units, and about 50 solid waste-fired units. Under Energy Scenario II (i.e., high natural gas prices), the projected total would consist of about 270 natural gas- and oil-fired units, about 420 coal-fired units, 70 wood-fired units, and 50 solid waste-fired units.

Standards based on either Regulatory Alternative A or B would not have a large impact on the total projected numbers of new steam generating units expected although there would be a slight shift in the projected mix of coal-, oil- and natural gas-fired units. Under the less restrictive Regulatory Alternative A, 90 to 415 coal-fired units and 600 to 275 natural gas- and oil-fired units are projected under Energy Scenarios I and II, respectively. Under the more restrictive Regulatory Alternative B, 75 to 380 coal-fired units and 615 to 315 natural gas- and oil-fired units are projected under Energy Scenarios I and II, respectively.

Similarly, standards based on either Regulatory Alternative A or B would not have a large impact on the coal penetration as a percentage of fossil fuel demand. Under Energy Scenario I, the coal penetration at the baseline is 24 percent of the total fossil fuel demand. Coal penetration is reduced to 21 percent and 19 percent, respectively, under Regulatory Alternatives A and B. Under Energy Scenario II, coal penetration at the baseline is 75 percent of the fossil fuel demand. Coal penetration is reduced to 74 and 70 percent, respectively, under Regulatory Alternatives A and B. The above discussion indicates that the greatest amount of fuel switching occurs under Energy Scenario I (low gas prices) and Regulatory Alternative B. The least fuel switching occurs under Energy Scenario II (high gas prices) and Regulatory Alternative A.

Table 7 summarizes the national incremental environmental and cost impacts of both Regulatory Alternatives A and B under Energy Scenario I. Table 8 summarizes the national impacts of each alternative under Energy Scenario II. As expected, the greatest reduction in particulate matter emissions under either scenario would be achieved by standards based on Regulatory Alternative B; however, standards based on this alternative would also result in the highest national cost impacts. For example, as shown in Table 7 for Energy Scenario I national particulate matter emissions would be reduced by about 22,000 Mg (24,000 tons) per year under Regulatory Alternative B, compared to a reduction of about 19,000 Mg (21,000 tons) under Regulatory Alternative A. Similarly, national NO_x emissions would be reduced by 28,000 Mg (31,000 tons) per year under Regulatory Alternative B, compared to a reduction of 26,000 Mg (29,000 tons) under Regulatory Alternative A. For Energy Scenario I, the total annualized cost would be $30 million under Regulatory Alternative B, compared to a cost of $28 million under Regulatory Alternative A.

TABLE 7.—NATIONAL INCREMENTAL ENVIRONMENTAL AND COSTS IMPACTS ANALYSIS UNDER ENERGY SCENARIO I (LOWER NATURAL GAS PRICES)[1]

	Regulatory Alternative A	Regulatory Alternative B
Environmental Impacts (thousand Mg (thousand tons))[2]		
NO_x emissions reduction	26 (29)	28 (31)
PM emission reduction	19 (21)	22 (24)
PM_{10} emissions reduction	16 (17)	19 (21)
Cost Impacts (million $/yr)[3,4]		
Total annualized cost	28	30
Cost Effectiveness ($/Mg ($/ton))[4]		
NO_x control	230 (210)	180 (170)
PM control	1,160 (1,050)	1,150 (1,040)

[1] Values presented indicate incremental impacts over regulatory baseline (i.e., emissions reductions, increased costs).
[2] Environmental impacts in the fifth year following proposal of standards.
[3] Annualized cost in the fifth year following proposal of standards.
[4] 1982 dollars.

TABLE 8.—NATIONAL INCREMENTAL ENVIRONMENTAL AND COSTS IMPACTS ANALYSIS UNDER ENERGY SCENARIO II (HIGHER NATURAL GAS PRICES)[1]

	Regulatory Alternative A	Regulatory Alternative B
Environmental Impacts (thousand Mg (thousand tons))[2]		
NO_x emissions reduction	8 (9)	11 (12)
PM emissions reduction	37 (41)	45 (51)
PM_{10} emissions reduction	30 (32)	37 (40)
Cost Impacts (million $/yr)[3,4]		
Total annualized cost	45	62
Cost Effectiveness ($/Mg ($/ton))[4]		
NO_x control	2,000 (1,800)	1,700 (1,500)
PM control	800 (730)	970 (880)

[1] Values presented indicate incremental impacts over regulatory baseline (i.e., emissions reductions, increased costs).
[2] Environmental impacts in the fifth year following proposal of standards.
[3] Annualized cost in the fifth year following proposal of standards.
[4] 1982 dollars.

As shown in Table 8, this same general contrast in national impacts between Regulatory Alternative A can be seen under Energy Scenario II. The magnitude of impacts under either regulatory alternative is sensitive to natural gas price assumptions and the resulting predictions of new coal-fired steam generating unit capacity versus natural gas- or oil-fired steam generator capacity. Because of the relatively greater capacity and number of new coal-fired steam generating units predicted under Energy Scenario II (higher natural gas prices), the national particulate matter emission reductions and national costs of either regulatory alternative would generally be greater under Energy Scenario II than under Energy Scenario I. For example, for Regulatory Alternative B, reductions in particulate matter emissions under Energy Scenario II would be more than twice the reduction achieved under Energy Scenario I. This occurs because of greater potential for achieving emissions reductions from coal-fired steam generating units. Although the proposed NO_x standards are the same under both regulatory alternatives, greater NO_x emissions reductions are expected under Energy Scenario I. Energy Scenario I would result in the construction of a greater number of natural gas-fired steam generating units which would employ staged combustion burners for NO_x control. These units would yield greater NO_x emissions reductions than would be expected for comparable sized coal-fired boilers which would be constructed under Energy Scenario II and which would apply LEA/SCA.

Similarly, the total national annualized cost of particulate matter and NO_x control would be greater under Energy Scenario II than under Energy Scenario I due to the greater number of new coal-fired steam generators which would be required to install particulate matter control equipment. Since the cost of NO_x control techniques do not differ substantially between coal- and natural gas-fired units the total cost of NO_x control is essentially the same under either energy scenario.

Under each regulatory alternative and energy scenario, capital cost increases are less than would be expected. The total national capital cost for emissions control would be increased by less than $50 million under Regulatory Alternative A/Energy Scenario II and the capital cost increases would be negligible for the other three cases. Additional review indicates that these national impacts are realistic, however.

The small or negligible increases in capital cost resulting from adoption of standards can be explained by the fuel switching predicted by IFCAM. The capital cost of a coal-fired steam generating unit is approximately four times that of a natural gas- or oil-fired unit. Moreover, the cost of a fabric filter is only about one-sixth the cost of a coal-fired steam generating unit, and the cost of a sidestream separator is even a smaller fraction of the steam generator cost. Thus, the cost of particulate matter controls for the coal-fired steam generating units predicted by IFCAM is offset by the costs of other units switching to natural gas firing. Under Regulatory Alternative A and Energy Scenario II, the economics of fuel switching are least favorable due to the relatively high natural gas prices and relatively low cost of sidestream separators. In this case, impacts of fuel switching were not sufficient to offset the increase in capital costs associated with sidestream separators, thus resulting in an increased capital cost of $50 million over the baseline cost.

Solid and liquid waste impacts associated with standards based on Regulatory Alternatives A or B under either energy scenario are minimal. In some cases, solid waste generation actually decreases due to the fuel switching predicted by IFCAM. Similarly, the electrical energy demands of standards based on Regulatory Alternatives A or B under either energy scenario are minor, increasing the fossil fuel consumption for new industrial-commercial-institutional steam generating units by less than one half of one percent.

F Selection of Best System of Continuous Emission Reduction

The regulatory alternatives examined for control of nitrogen oxides emissions is the same under both Regulatory Alternative A and Regulatory Alternative B. Under both alternatives, low excess air is considered the most effective NO_x emissions control technique for mass-feed and spreader stoker coal-fired units. A combination of low excess air and staged combustion is considered the most effective NO_x emissions control technique for industrial-commercial-institutional steam generators firing pulverized coal, residual oil, or natural gas. For coal- and residual oil-fired units a combination of LEA and overfire air (OFA) is considered the most effective NO_x emissions control technique. Staged combustion burners (SCB's) are considered the most effective NO_x emissions control technique for industrial-commercial-institutional steam generating units firing natural gas or distillate oil. The impacts of standards based on these control techniques on industrial-commercial-institutional steam generating units during the first 5 years following proposal of standards are shown in Tables 7 and 8. As stated above, the magnitude of emissions reductions and costs varies according to energy price assumptions.

The cost-effectiveness of control of nitrogen oxides would range from $180 to $2,000/Mg ($170 to $1,800/ton), depending on which energy scenario and regulatory alternative is assumed. The national average cost-effectiveness of particulate matter control for Energy Scenario I under either Alternative A or Alternative B is about $1,160/Mg ($1,050/ton). For Energy Scenario II, the national average cost-effectiveness of particulate matter control is about $800/Mg ($730/ton) under Regulatory Alternative A and about $970/Mg ($880/ton) under Regulatory Alternative B. This difference in the cost impacts associated with the two alternatives is not compelling. Under neither alternative does the cost of the installation and operation of pollution control equipment result in any significantly adverse economic impacts.

In addition to national impacts, a review of impacts on individual steam generating units was conducted through a model unit analysis. The cost impacts on individual steam generating units varied depending on a number of factors, including steam generating unit size, fuel type, fuel cost, potential fuel savings, regulatory requirements, and compliance methods. As discussed under the *Economic Impact Assessment* section and as presented in Tables 9 through 14 below, the cost effectiveness of particulate matter and nitrogen oxides control on a model unit basis varied from less than $110/Mg ($100/ton) to more than $2,200/Mg ($2,000/ton) of pollutant removed.

A comparison of the regulatory alternatives in reducing particulate matter emissions from industrial-commercial-institutional steam generating units shows that Regulatory Alternative B is superior in controlling both total particulate matter and the inhalable particulates smaller than 10 microns in diameter. In terms of total particulate matter control, standards based on Regulatory Alternative B would result in an approximate 20 percent greater emission reduction than standards based on Regulatory Alternative A. Similarly, for inhalable particulate matter emissions, standards based on Regulatory Alternative B would also result in an approximate 20 percent greater emissions reduction than standards based on Regulatory Alternative A. The greater reduction in emissions of particulate matter smaller than 10 microns in diameter which is achievable under Regulatory Alternative B is significant because particulate matter less than 10 microns in size is capable of being inhaled into the lungs. Therefore, the cost impacts between

Regulatory Alternatives A and B is a comparison between a less costly alternative which principally removes larger particles and a more costly alternative which effectively removes the inhalable particles which have the most direct impact on human health.

An additional benefit associated with the selection of Regulatory Alternative B as the best system of emission reduction is that this regulatory alternative is more consistent with the requirements of most existing Federal and State regulatory programs for controlling particulate matter emissions from steam generating units than is Regulatory alternative A. Based on a survey of SIP regulations, it is expected that over half of all new coal-, wood- and solid waste-fired steam generating units above 29 MW (100 million Btu/hour) heat input capacity would be required by existing State regulations to install the same emission control technology as that which would be required by standards based on Regulatory Alternative B. In addition, well over 90 percent of the recent PSD determinations under Federal and State Prevention of Significant Deterioration and New Source Review procedures have required the use of the same emission control technologies as those required by Regulatory Alternative B for steam generating units larger than 29 MW (100 million Btu/hour) heat input capacity. The selection of Regulatory Alternative B, therefore, as the basis of the proposed standards is consistent with existing State and Federal regulatory programs. Regulatory Alternative B, therefore, has been selected as the basis of the proposed standards.

Performance Test Methods and Monitoring Requirements. The performance testing and emission monitoring requirements included in the proposed regulation would apply to each steam generating unit that is subject to either the proposed particulate matter or the proposed NO_x emission limits.

Particulate Matter. An initial performance test would be required for all steam generating units subject to the proposed particulate matter emission standard. For steam generating units firing a mixture of fuels, the performance test would be conducted while the steam generating unit is firing a fuel mixture representative of the "worst case" (from the viewpoint of the highest particulate matter emissions) the owner or operator reasonably anticipates might be fired in the future. The performance test would be conducted in accordance with Reference Method 5 or Reference Method 17 (40 CFR Part 60, Appendix A). Reference Methods 1 through 4 would be used for determining the number and location of sampling points, flue gas flow rates, flue gas composition, and flue gas moisture content. After the initial performance test, subsequent performance tests may be required by enforcement personnel. All performance tests would consist of a minimum of three Reference Method 5 or Reference Method 17 runs at or near full-load operating conditions. The average particulate matter emission rate of the three runs would be used to determine compliance. Reference Method 17 could be used in place of Reference Method 5 for facilities without wet FGD systems that have stack gas temperatures of less than 160°C (320°F).

Comments have been received which state that Reference Method 5 and Reference Method 17 are inappropriate for measuring particulate matter emissions from steam generating units equipped with wet FGD systems. The problems raised concerning the use of these methods stem from the condensation of sulfuric acid in the flue gas when cooled by a wet scrubber, and the inclusion of this acid mist in the measurement of particulate matter under Reference Method 5. This problem is being studied and if it is concluded that an amendment to Reference Method 5 would be appropriate, such a change will be proposed in the future.

Continuous monitoring methods do not presently exist for measuring particulate matter emission rates directly. Therefore, the proposed monitoring requirements include other methods to indicate if the particulate matter emission control system is properly operated and maintained. Opacity data would be recorded and reduced to 6-minute averages.

The use of a transmissometer to monitor continuously the opacity of visible emissions would serve as an indicator of proper operation and maintenance of the control device. Periods of high opacity would provide a strong indication that particulate matter emissions are in excess of the proposed emission limits. Periods of high opacity, therefore, would indicate that a performance test may be appropriate to determine if the steam generating unit is in compliance with the particulate matter standards.

Opacity standards are established at levels consistent with mass emission standards to provide an inexpensive indicator of a particulate matter control system's performance. To account for factors such as unusually large diameter stacks or unique fuel properties which can influence opacity, provisions are available [40 CFR 60.11(e)] to obtain site-specific opacity standards when a facility is unable to comply with the opacity standard but demonstrates compliance with the mass emission standard.

Nitrogen Oxides. Under the proposed standards, continuous NO_x emission monitoring would be required for all steam generating units with heat input capacities greater than 29 MW (100 million Btu/hour) and which have an annual capacity factor for coal, oil, or natural gas greater than 30 percent (0.30). The first 30-day average of NO_x emissions after initial unit startup would serve as the initial performance test required under § 60.8. Thereafter, the continuous monitoring data would be used to determine a 30-day rolling average NO_x emission rate calculated as the arithmetic average of the preceding 720 hourly NO_x values. Owners and operators of steam generating units would be required to submit excess emission reports semiannually if the NO_x standard was exceeded for any 30-day average during the reporting period and the data may be used for compliance purposes. Otherwise, no reports would be required. All continuous NO_x emission monitoring records would have to be maintained at the steam generating unit site for a period of two years.

For steam generating units which have an annual heat input capacity between 5 percent and 30 percent (0.05 to 0.30) for coal, oil, or natural gas, a continuous NO_x emission monitor would be used to conduct an initial 30-day compliance test. Thereafter, the owner or operator of the facility could elect to monitor either steam generating unit operating conditions or NO_x emissions. If operating conditions are monitored, operating conditions such as the level of excess oxygen or the degree of staging (i.e., ratio between primary air and secondary and/or tertiary air) may be selected for monitoring. Other steam generating unit operating conditions may be monitored. The proposed standards require that the owner or operator of the facility submit a plan to the Administrator with the notification of construction or reconstruction specifying what conditions are to be monitored, the variation expected in these conditions with operating load, the data used to determine that these conditions are indicative of nitrogen oxides emission control, and the procedures and formats to be followed in monitoring and recordkeeping. Upon receipt of the plan, the Administrator shall approve or disapprove of the plan within 45 days. Manufacturers of steam generating units may develop and provide monitoring plans for common steam generating unit designs. Manufacturer developed plans would subsequently be submitted by the owner or operator of the steam generating unit. Following approval, the owner or operator of the facility shall maintain records of the operating conditions, including steam generating unit load, identified in the plan. These records shall be retained for 2 years.

IV Modification and Reconstruction Provisions

Existing steam generating units that are modified or reconstructed would be subject to the requirements in the General Provisions (40 CFR 60.14 and 60.15) which apply to all new source performance standards, with the exception that modified steam generating units would not be required to meet the proposed NO_x standards. Few, if any, changes typically made to existing steam generating units would be expected to bring such steam generating units under the proposed particulate matter standards.

A modification is any physical or operational change to an existing facility which results in an increase in emissions. Changes to an existing facility which do not result in an increase in emissions, either because the nature of the change has no effect on emissions or because additional emission control technology is employed to offset an increase in emissions, are not considered modifications. In addition, certain changes have been exempted under the General Provisions (40 CFR 60.14). These exemptions include: routine maintenance, repair, and replacement; production increases achieved without any capital expenditure; production increases resulting from an increase in the hours of operation; addition or replacement of equipment for emission control (as long as the replacement does not increase emissions); relocation or change of ownership of an existing facility; and use of an alternative fuel or raw material if the existing facility was designed to accommodate it. In addition, both section 111 of the Clean Air Act asnd 40 CFR 60.14 of the General Provisions exempt mandatory conversions to coal.

Reconstruction of an existing facility could make that facility subject to a new source performance standard, regardless of any change in the emission rate, depending on the cost of the replaced components and the feasibility of meeting the standards. Rebuilt steam generating units would become subject to the proposed particulate matter standards under the reconstruction provisions, regardless of changes in emission rate, if the fixed capital cost of reconstruciton exceeds 50 percent of the cost of an entirely new steam generating unit of comparable design and if it is technologically and economically feasible to meet the applicable standards. Costs associated with steam generating unit maintenance are not included in determining reconstruction costs.

Steam generating units which would become subject to the standard as a result of modification would be exempt from the NO_x standards under the proposed standards. Because demonstrated NO_x control systems must be incorporated as part of the basic design of the steam generating unit, rather than installed as add-on flue gas controls, it is unreasonable to require that modified steam generating units be subject to the proposed NO_x control requirements. These units are not exempted from the proposed particulate matter standard because particulate matter control technologies, such as fabric filters and ESP's, may be added to existing facility, where appropriate, without requiring the alteration of the steam generating unit itself. Reconstructed units are not extended a general exemption from the proposed NO_x standards because the provisions of § 60.15 include a procedure for considering the technological and economic feasibility of achieving the standard in determining whether a reconstructed unit would become subject to the proposed standard.

V Analysis of Information Requirements

The proposed standards would require that EPA be notified of the initial steam generating unit startup for all affected facilities and of the planned date for initial compliance testing. Following the initial compliance test, a report would be submitted summarizing the compliance test results and the performance evaluation of the continuous monitoring system (if applicable). Following startup, records of certain steam generating unit operating factors and emissions would be maintained. As proposed, the types of operational and emissions records required would depend primarily on the type of fuel fired. Records would be maintained on site for at least 2 years.

The notification requirements included in the General Provisions of 40 CFR Part 60 (i.e., §§ 60.7(a) and 60.8(a)), which apply to all standards of performance, would require submittal of two types of notifications. First, a notification would be required informing EPA of an owner or operator's intention to initiate operation of a new, modified, or reconstructed steam generating unit. This would include notification of construction or reconstruction, date of anticipated startup, and anticipated date of demonstration of the continuous emission monitoring systems (if applicable). In the case of steam generating units that are not field erected (i.e., packaged steam generating units), notification of the date when fabrication commences would be required. Following startup, a second notification would be required. This notification would be a report of the results of the initial particulate matter and NO_x performance test and initial performance evaluations of the continuous emission monitoring systems, if applicable.

The proposed standards require that the owner or operator of an affected facility which has an annual capacity factor between 5 percent and 30 percent (0.05 to 0.30) for coal, oil, or natural gas continuously monitor either nitrogen oxides emissions or other steam generating unit operating conditions which are indicative of the level of nitrogen oxides emission control. If the owner or operator elects to monitor steam generating unit operating conditions, the proposed standards require that a plan for monitoring be submitted with the notification of construction or reconstruction which specifies what conditions are to be monitored, the variation in those conditions expected with changes in boiler load, the data supporting the conclusion that those conditions are indicative of nitrogen oxides emission control, and the procedures and formats to be followed in monitoring and recordkeeping.

After initial startup, the proposed regulation would require that various records be kept and semiannual reports of excess NO_x emissions or opacity levels, as applicable, be submitted if any excess emissions occurred. The records would vary with the type of fuel fired. For example, minimal records would be required for natural gas-fired steam generating units and more extensive records would be required for pulverized coal-fired steam generating units. The proposed recordkeeping requirements would require that at least one and at most four types of records be maintained. First, the amount and type of fuel fired in each calendar year would be recorded. These data, in conjunction with the steam generating unit capacity rating, would be used to determine the annual capacity factor of the steam generating unit, and, thus, the particulate matter standard to which the steam generating unit is subject.

The second recordkeeping requirement would require that records of the data output of the continuous emission monitoring systems, if applicable, be maintained for 2 years. Opacity data would be reduced to 6-minute averages. NO_x emission data would be reduced to 30-day rolling averages.

The third recordkeeping requirement would require that records of the amounts of fuels cofired in the steam generating unit be maintained for those fuels subject to the proposed NO_x standard. Additionally, for residual oil-fired steam generating units, records of the fuel specifications would be maintained to determine the residual oil fuel nitrogen content. Fuel specification sheets normally obtained with each shipment of oil would comply with this requirement. These records would be used to determine the application NO_x emission limits.

The fourth type of recordkeeping requirement would require that records be maintained on the operation and maintenance of the continuous emission monitoring systems. This provision would require that records be kept identifying any periods when continuous monitoring data were not available due to malfunction of the monitoring systems, when repair of the system was initiated, when repair of the system was completed, and what repairs were made. The records would also indicate if any changes were made in the operation of the emission control system during the period in which monitoring data were unavailable. These records would permit enforcement personnel to determine if the continuous monitoring system was being properly operated and maintained during enforcement inspections or audits.

All required records would be retained for 2 years following the date of such records, after which they could be discarded. The reporting and recordkeeping requirements in the proposed regulation are necessary to inform enforcement personnel as new steam generating units initiate operation. In addition, they would provide the data and information necessary to ensure continued compliance of these steam generating units with the proposed regulation. At the same time, these requirements would not impose an unreasonable burden on steam generating unit owners or operators.

The Paperwork Reduction Act (PRA) of 1980 (Pub. L. 96-511) requires that the Office of Management and Budget (OMB) approve reporting and recordkeeping requirements that qualify as an "information collection request" (ICR) before the reporting and recordkeeping requirements are promulgated as final. Reporting and recordkeeping requirements qualify as an ICR if they satisfy the criteria in the PRA's definition of "collection of information." For the purpose of accommodating OMB's 2-year approval period, a 2-year time period has been used in the impact analysis for estimating the burden on industry of the reporting and recordkeeping requirements included in the proposed regulation.

The information provisions associated with this proposed rule (40 CFR 60.7, 40 CFR 60.466) have been (or will be) submitted for approval to the Office of Management and Budget (OMB) under the Paperwork Reduction Act of 1980 U.S.C. 3501 *et seq.* Comments on these requirements should be submitted to the Office of Information and Regulatory Affairs of OMB—marked Attention: Desk Office for EPA. The final rule package will respond to any OMB or public comments on the information collection provisions.

The average annual industrywide burden of the reporting and recordkeeping requirements associated with the proposed regulation would be 110 person-years, based on an average of 162 respondents per year.

VI Regulatory Flexibility Analysis

The Regulatory Flexibility Act requires consideration of the impacts of proposed regulations on small entities including small businesses, organizations, and jurisdictions. A small business is defined as any business concern which is independently owned and operated and not dominant in its field as defined by the Small Business Administration regulations under section 3 of the Small Business Act. Similarly, a small organization is defined by the Small Business Administration as a not-for-profit enterprise, independently owned and operated, and not dominant in its field. A small jurisdiction is defined as any governmental district with a population of less than 50,000 people. Although the minimum steam generating unit size cutoff of 29 MW (100 million Btu/hour) heat input capacity included in the proposed regulation would exempt almost all small entities, it is possible that some small entities would be affected, especially in the commercial and institutional sectors.

If a substantial number of small entities would be affected by a proposed regulation, the Regulatory Flexibility Act requires an analysis of the potential impacts of the regulation. It is not feasible to identify the number of small businesses which could be affected by the proposed standards. Consequently, a number of specific industries were examined to determine whether a typical small business within that industry could be significantly impacted by the proposed regulations. These specific industries were judged those most likely to experience adverse cost-related impacts due to a high ratio of steam consumption to production costs in steam intensive production processes, seasonal steam requirements that result in operation of a plant's steam generating units at low capacity factors, and the likelihood of financial problems where small firms are involved. An additional criterion for selecting entities with nonfossil fuel-fired steam generating units for analysis was the amount of nonfossil fuel presently burned within the industry in relation to total steam generating unit fuel consumption. The municipalities were chosen for the nonfossil fuel-fire steam generating unit analysis based on the potential for adverse economic impact on the municipal finance structure posed by potential regulation. All of the municipalities chosen either operate or have the potential to operate municipal solid waste-fired steam generating units for the disposal of solid wastes and for the generation of steam or electric power for use by the municipality or for sale.

Eleven industries were selected to determine if the impacts on small businesses, as defined by the Small Business Administration (SBA), were significant. The eleven industries selected for analysis were: Beet sugar, reclaimed rubber, canneries, distilled liquor, automobile manufacturing, iron and steel, petroleum refining, furniture, sawmills, plywood, and paper. For municipalities were also analyzed. The SBA definition of small business firms within each industry is based on the number of employees per firm. The average number of employees for small business firms within each industry were determined using U.S. Census Bureau data.

The analysis indicates that small businesses within some of the selected industries would be excluded from the proposed regulation due to their small size and the 29 MW (100 million Btu/hour) heat input capacity minimum steam generating unit size cutoff included in the proposed regulation. The analysis also indicates that the impact on produce prices for small business in the remaining industries would not be significant. Product price increases of 5 percent or greater have been identified as significant in guidelines issued under Executive Order 12044, Improving Federal Regulations (now superceded by Executive Order 12291). These product price increases would be less than 5 percent. The cost impact for the typical small business is less then 1 percent. As discussed in the foregoing section of this preamble entitled "Consideration of Economic Impacts" a similar evaluation for municipalities leads to the same conclusion.

The analysis also considered capital availability. The potential impact of the proposed regulation on cash flow and debt/equity ratios under a variety of debt/equity financing strategies was examined. The analysis indicates that the proposed regulation would result in no significant changes in these ratios. Since the capital available to a business is at least equal to that required to construct the new steam generating unit, the proposed regulation would not adversely impact capital availability.

The proposed regulation would only apply to new steam generating units. No existing steam generating units are expected to be reconstructed or modified, and therefore existing units would not be affected by the proposed standards. Consequently, the proposed regulations would not result in any business closures.

Based on this analysis, the proposed regulation would have no significant adverse impacts on small entities. Consequently, alternative regulations under the Regulatory Flexibility Act are not necessary to minimize potential impacts on small entities.

VII. Public Hearing

A public hearing will be held to discuss the proposed standards in accordance with section 307(d)(5) of the Clean Air Act. Persons wishing to make presentations should contact EPA at the address given in the ADDRESSES section of this preamble. Oral presentations should be limited to 15 minutes each. Any member of the public may file a written statement before or within 30 days after the hearing. Written statements should be mailed to the Central Docket Section at the address given in the ADDRESSES section of the preamble.

A verbatim transcript of the hearing and written statement will be available for public inspection and copying during normal working hours at EPA's Central Docket Section in Washington, D.C. (see ADDRESSES section of this preamble).

VIII. Docket

The docket is an organized and complete file of all the information submitted to or otherwise considered in the development of this proposed rulemaking. The principal purposes of the docket are (1) to allow interested parties to identify and locate documents so that they can effectively participate in the rulemaking process and (2) to serve as the record in case of judicial review.

IX. Request for Comments

As prescribed by section 111 of the Clean Air Act, proposal of standards of performance for industrial-commercial-institutional steam generating units was preceded by the Administrator's determination (40 CFR 50.15, 44 FR 49222, August 21, 1979) that industrial-commercial-institutional steam generating units contribute significantly to air pollution which may reasonably be anticipated to endanger public health or welfare. In accordance with section 117 of the Act, publication of this proposal was preceded by consultation with appropriate advisory committees, independent experts, and Federal departments and agencies. The Administrator will welcome comments on all aspects of the proposed regulation, including economic and technological issues, and on the proposed test methods.

Several issues raised during development of the proposed standards warrant special consideration. The background and a proposed approach to each of these issues is presented in the following discussion.

Cogeneration Steam Generators—Emission Credits

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 utility's avoided cost, which makes on-site cogeneration economically attractive.

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 an efficient electric/thermal energy production technology and a number of different types of cogeneration systems are available, while others are being developed. For the present, steam generator-based, gas turbine-based, and diesel-based cogeneration systems are the only available technologies. In the future, fuel cells and stirling engines may also become available for cogeneration systems.

In a steam generator-based cogeneration system, the simultaneous production of electric power and process heat is achieved by first supplying the steam produced by the steam generator to a steam turbine-electric generator set for electric power generation and then applying the steam turbine exhaust in a process to provide process heat. The actual steam generator used for an on-site cogeneration system would be slightly larger than the conventional process heat steam generator it replaced, but it would still be small enough so that the total fuel use during cogeneration would be less than the total of the displaced power plant fuel use and displaced process heat steam generator fuel use. One particularly desirable feature of steam generator-based cogeneration systems is their ability to fire a wide range of fuels, including coal, oil, natural gas, wood, and even municipal-type solid waste. Gas turbine- or diesel-based cogeneration systems are currently limited to firing either gaseous fuels or liquid fuels.

The potential for regional energy saving through the use of a steam generator-based cogeneration system, compared to the use of a separate steam generator for electric power generation and a separate steam generator for process heat production, can range from 5 percent to almost 30 percent depending on the specific industry using the cogeneration system.

Reduced regional fuel consumption achieved by cogeneration systems can result in regional emission reductions. For example, if a cogeneration system reduces regional fuel use by 15 percent and displaces a utility power plant and a process heat steam generator that were all subject to the same emission limitation, regional emissions would be similarly reduced by 15 percent. It has been suggested, therefore, that the proposed 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 systems, and no regional emission reduction would occur. For a coal-fired steam generator subject to the proposed emission limit of 22 ng/J (0.05 lb million Btu) heat input, a 15 percent emission credit reflecting the potential decrease in regional emissions would increase the emission limit in the proposed standards to 25 ng/J (0.06 million lb Btu) heat input.

In cases where different emission standards are applicable to the displaced power plant than to the cogeneration system, or different fuels are fired in the displaced power plant that in the cogeneration system, the environmental and fuel use impacts of cogeneration becomes less clear and the analysis becomes much more complex. For example, in cases where a new cogeneration system achieves emission levels lower than an older power plant which is being displayed by congeneration, a 15 percent regional energy savings may result in more than a 15 percent reduction in regional emissions. On the other hand, in cases where a new cogeneration system achieves emission levels higher than a new power plant which is being displaced by cogeneration, a 15 percent regional energy savings may result in less than a 15 percent reduction in regional emissions. If hydro-electric or nuclear power generation capacity is being displaced by cogeneration, regional emissions would increase.

Similary, a 15 percent reduction in regional energy use does not guarantee fuel savings of premium gaseous or liquid fuels. In cases where the cogeneration system is firing coal and displaces a coal-fired power plant, the 15 percent regional energy savings would translate in a 15 percent reduction in regional coal use. However, in cases where the new cogeneration system fires natural gas or fuel oil and displaces a coal-fired utility power plant (or nuclear or hydro-electric plant), the 15 percent reduction in regional energy use would result in an increase in natural gas or fuel oil consumption and a decrease in coal consumption.

Relative to local emission, it should be noted that a larger steam generator is used for cogeneration than would be used for process heat alone. Consequently, local emissions at the cogeneration site would increase in all cases.

Emission credits must also be considered in relation to the overall goals of new source performance standards. Under section 111 of the Clean Air Act, new source performance standards

> shall reflect the degree of emission limitation and the precentage reduction achieved through application of the best technological system of continuous emission reduction * (taking into consideration the cost of achieving such emission reductions, and any nonair quality health and environmental impact and energy requirements).

Emission credits for cogeneration systems would allow for the application of less than the best technological system of emission control without offsetting benefits in many cases and would reduce the environmental performance of cogeneration systems.

In summary, cogeneration systems would reduce total regional energy use; however, regional or local emission reductions are not guaranteed in all cases. Environmental benefits can result from cogeneration, but whether such benefits actually occur is totally dependent on site-specific conditions, and allowing emission credits for cogeneration may negate any potential environmental benefits.

The proposed standards, therefore, are neutral and neither encourage nor discourage cogeneration systems. The same standards would apply to steam generators whether they are used for cogeneration or not. Thus, the proposed standards would maintain any environmental benefits that result through the use of cogeneration.

Combined Cycle Steam Generators—Emission Credits

Combined cycle units represent another type of cogeneration technology and consist of a gas turbine connected to a steam generator. The steam generator is used to recover heat from the gas turbine exhaust. Steam generators used in combined cycle units fall into one of three categories depending on how much fuel is fired in the steam generator: unfired, supplementary-fired, and fully-fired arrangements.

In the unfired arrangement, all of the heat input to the steam generator 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 generator, with the remaining 30 percent being supplied by the fuel fired in the steam generator. Unfired or supplementally-fired units typically use modular finned-type heat exchangers to recover heat from the gas turbine exhaust. Because of thermal limitation of modular-type heat exchangers, the amount of supplementary fuel fired is necessarily limited. Also, because of potential fouling problems, only clean fuels such as natural gas or fuel oil are used for supplementary-fired steam generator fuels. The supplemental firing of natural gas or fuel oil is accomplished by the use of a "grid" burner installed in the gas turbine exhaust duct. The gas turbine exhaust with its high oxygen content (up to 15 percent oxygen by volume) is used to satisfy the combustion air requirements of the grid burner.

Fully-fired units employ a conventional steam generator for heat recovery and the fuel firing rate in the steam generator is not restricted by thermal limitations. Sufficient fuel is fired in the steam generator to reduce the oxygen content of the gas turbine exhaust to approximately 3 percent or less, as typically achieved in conventional steam generators. In the fully-fired arrangement, the gas turbine exhaust provides approximately 25 percent of the heat input to the steam generator, with the remaining 75 precent being supplied by fuel fired in the steam generator.

To date, as a result of both technical and economic considerations, both supplementary-fired and fully-fired combined cycle steam generators have been constructed to fire either natural gas or fuel oil. Coal has not been fired in a combined cycle steam generator. The combustion of coal in an atmosphere of 15 percent of less oxygen (gas turbine exhaust) could lead to combustion stability problems. Additionally, the handling, preparation, and firing of coal greatly increase the complexity and cost of the combined cycle steam generator. If coal were fired in a combined cycle steam generator, it would be fired in a fully-fired combined cycle steam generator rather than in a supplementary-fired steam generator because of the fouling and erosion problems that would be experienced by modular heat exchangers used in supplementary-fired units.

It has been suggested that an emission credit should be applied toward the proposed standards for combined cycle steam generators based on the heat input supplied to the steam generator by the gas turbine exhaust. Such credits would result in higher emission limits for combined cycle steam generators depending on the amount of gas turbine exhaust heat supplied to the steam generator.

The magnitude of this credit would be different for different fuels and pollutants. For particulate matter, the practical effect of such a credit would be negligible. First, natural gas and fuel oil are the only fuels which have been used to date in combined cycle steam generators. With the exception of high ash content residual oils, these fuels result in negligible particulate matter emissions. No particulate matter emission standards are proposed for these fuels; therefore, emission credits would not apply in these cases.

For residual oil firing, where high ash contents could potentially necessitate particulate matter emission control, fuel oil pretreatment or fuel oil blending for sulfur dioxide emission control effectively reduces fuel ash content. This results in control of both sulfur dioxide and particulate matter emissions and post-combustion particulate matter emission control for oil-fired steam generators is closely associated with the development of standards for the control of sulfur dioxide emissions. Consequently, any decision on a particulate matter emission standard for residual oil-fired steam generators is being reserved for consideration at the time sulfur dioxide standards are developed. Thus, no particulate matter emission standard for residual oil-fried steam generating units is included in this proposal and emission credits would not be applicable.

If any coal-fired combined cycle steam generators were to be constructed, particulate emission control would be necessary. Although coal-fired combined cycle steam generators have not been built for both technical and economic reasons, an analysis was performed to determine the effects of allowing emission credits for gas turbine heat input toward particulate matter control requirements for coal-fired, fully-fired combined cycle steam generators. In fully-fired combined cycle steam generator applications, the gas turbine exhaust would provide approximately 25 percent of the heat input into the steam generator. The allowance of the suggested emission credits would increase the allowed particulate matter emissions from coal-fired combined cycle steam generators by approximately 25 percent. The emission credit would effectively increase the proposed particulate matter emission standard for coal-fired combined cycle steam generators from 22 ng/J (0.05 lb/million Btu) heat input up to approximately 29 ng/J (0.07 lb/million Btu) heat input. If an electrostatic precipitator were used for emission control, emission credits for coal-fired combined cycle steam generators would reduce the annual costs associated with emission control by less than 5 percent. This would improve the average cost-effectiveness of emission control by less than $45/Mg ($50/ton) of particulate matter removed.

For particulate matter standards, any benefit or cost savings resulting from the use of emission credits for gas turbine exhaust heat input appear to be theoretical, as natural gas or fuel oil will in all likelihood continue to be the fuels fired in combined cycle steam generators. Even if coal were to be fired in combined cycle steam generators, the average cost-effectiveness of particulate matter emission control to comply with the proposed standards is less than $450/Mg ($500/ton) of particulate matter collected with or without an emission credit and is considered reasonable in either case. The proposed standards for particulate matter, therefore, do not provide an emission credit for combined cycle generators.

The proposed stanards do include NO_x emission limits for natural gas- oil- and coal-fired steam generators. The allowed use of emission credits would effectively allow increased NO_x emissions from combined cycle steam generators. Available NO_x emissions data from combined cycle steam generators, however, suggests that NO_x emission rates from these types of units are less than what would be expected for conventional steam generators. The gas turbine exhaust with its low oxygen content appears to have an effect similar to flue gas recirculation in suppressing NO_x emissions resulting from thermal NO_x formation. Consequently, combined cycle steam generators firing natural gas or fuel oil appear to have NO_x emission levels comparable to or even lower than conventional steam generators with NO_x control. As a result, it appears that NO_x emission credits for combined cycle steam generators are unnecessary.

If the effect of the gas turbine exhaust on NO_x formation in the combined cycle steam generator is analogous to that of flue gas recirculation, NO_x emissions from firing residual oils or coal in the steam generator may require the additional use of staged combustion air (SC) to maintain low NO_x emission rates. While flue gas recirculation is effective in suppressing thermal NO_x formation, it is generally ineffective in suppressing fuel nitrogen NO_x formation. Thus, combined cycle steam generators firing higher nitrogen content residual oils or coal may have to employ SC to reduce NO_x emission. The limited NO_x emission data available for combined cycle units indicates that SC can be used in combined cycle steam generators and that the proposed NO_x emission limits are achievable with combined cycle steam generators.

Emission credits for NO_x emissions would not significantly reduce NO_x control costs. As discussed earlier, the principal cost of NO_x control is associated with the NO_x (or flue gas O_2) continuous monitoring system. Emission credits would not reduce these costs. Thus, emission credits would not result in any cost savings nor improve the cost-effectiveness of NO_x control.

In summary, the proposed standards for particulate matter and NO_x do not include an emission credit for combined cycle steam generators. This would have no adverse impact on continued applications of combined cycle gas turbines.

Staged Combustion Burners

Site-specific permits for NO_x control have resulted in the limited application of staged combustion burners (SCB). As decribed under the *Demonstrated Control Techniques—NO_x* section of this preamble, rapid strides have been made in development of SCB technology. Comments are requested on: (1) The current availability, performance, and level of commercial demonstration of SCB technology for natural gas-, distillate oil-, residual oil-, and pulverized coal-fired steam generating units and (2) on the reasonableness of considering SCB technology as a basis for NO_x emission standards for these fuels. The proposed NO_x emission standards for natural gas- and distillate oil-fired steam generating units are based on the use of SCB technology, but the proposed standards for residual oil- and pulverized coal-fired units are not based on SCB technology. If the data are submitted which support the application of SCB technology to residual oil- and pulverized coal-fired units, SCB technology will be considered for the basis of the final NO_x emission standards for residual oil- and pulverized coal-fired steam generating units. If SCB technology is selected for the basis of the final NO_x standards, then the effective date for the NO_x standards for residual oil- and pulverized coal-fired steam generating units would be the date of promulgation of the standards and not the date of today's proposal.

X. Miscellaneous

It should be noted that standards of performance for new sources established under section 111 of the Clean Air Act reflect:

> application of the best technological system of continuous emission reduction which (taking into consideration the cost of achieving such emissions reduction, any nonair quality health and environmental impact and energy requirements) the Administrator determines has been adequately demonstrated (section 111(a)(1)).

Although there may be an emission control technology available that can reduce emissions below those levels required to comply with standards of performance, this technology might not be selected as the basis of standards of performance due to costs associated with its use. Accordingly, standards of performance should not be viewed as the ultimate in achievable emission control. In fact, the Act requires (or has the potential for requiring) the imposition of a more stringent emission standard in several situations. For example, applicable costs do not necessarily play as prominent a role in determining the "lowest achievable emission rate" for new or modified sources located in nonattainment areas (i.e., those areas where statutorily-mandated health and welfare standards are being violated). In this respect, section 173 of the Act requires that new or modified sources constructed in an area where ambient pollutant concentrations exceed the National Ambient Air Quality Standard (NAAQS) must reduce emissions to the level that reflects the "lowest achievable emission rate" (LAER), as defined in section 171(3) for such category of source. The statute defines LAER as the rate of emissions based on the following, whichever is more stringent:

(a) The most stringent emission limitation which is contained in the implementation plan of any State for such class or category of source, unless the owner or operator of the proposed source demonstrates that such limitations are not achievable, or

(b) The most stringent emission limitation which is achieved in practice by such class or category of source.

In no event can the emission rate exceed any applicable new source performance standard (section 171(3)).

A similar situation may arise under the prevention of significant deterioration of air quality provisions of the Act (Part C). These provisions require that certain sources (referred to in section 169(1)) employ "best available control technology" (BACT) as defined in section 169(3) for all pollutants regulated under the Act. Best available control technology must be determined on a case-by-case basis, taking energy, environmental and economic impacts and other costs into account. In no event may the application of BACT result in emissions of any pollutants which will exceed the emissions allowed by any applicable standard established pursuant to section 111 (or 112) of the Act.

In all events, State implementation plans (SIP's) approved or promulgated under Section 110 of the Act must provide for the attainment and maintenance of NAAQS designed to protect public health and welfare. For this purpose, SIP's must, in some cases, require greater emission reduction than those required by standards of performance for new sources.

Finally, States are free under section 116 of the Act to establish even more stringent emission limits than those established under section 111 or those necessary to attain or maintain the NAAQS under section 110. Accordingly, new sources may in some cases be subject to limitations more stringent than standards of performance under section 111, and prospective owners and operators of new sources should be aware of this possibility in planning for such facilities.

The proposed standards would be reviewed 4 years from the date of promulgation as required by the Clean Air Act. This review would include an assessment of such factors as the need for integration with other programs, the existence of alternative methods, enforceability, improvements in emission control technology, and reporting requirements. The reporting requirements in the proposed standards would be reviewed as required under EPA's sunset policy for reporting requirements in regulations.

Economic Impact Assessment

Section 317 of the Clean Air Act requires the Administrator to prepare an economic impact assessment for any new source standard of performance promulgated under section 111(b) of the Act. An economic impact assessment was prepared for the proposed standards and for other regulatory alternatives. All aspects of the assessment were considered in the formulation of the proposed standards to ensure that the proposed standards would represent the best system of emission reduction considering costs. Portions of the economic impact assessment are included in the Background Information Documents and additional information is included in the Docket.

Under Executive Order 12291, EPA is required to judge whether a regulation is judged to be a "major rule" and, therefore, it is subject to certain requirements of the Order. This regulation will result in none of the economic effects set forth in Section 1 of the Order as grounds for finding a regulation to be a "major rule." The net annualized costs through the first 5 years of implementation, including depreciation and interest, are projected to be below the threshold cost for defining a "major rule." Only negligible increases in product prices attributable to implementation of these standards are expected. Therefore, this regulation is not a "major rule" under Executive Order 12291.

The cost effectiveness of emission control for individual industrial steam generating units that would be subject to the proposed standards would differ from the national average cost-effectiveness levels. Tables 9 through 14 present particulate matter and nitrogen oxides emission control cost, emissions reduction, average cost effectiveness, and incremental cost-effectiveness data for a range of individual steam generating units that would be covered by the proposed standards.

Specifically, Tables 9 and 10 contain particulate matter emission control cost, emissions reduction, and cost-effectiveness data for five sizes of coal-fired steam generating units, two wood-fired units and two municipal type solid waste-fired units. Tables 11 through 14 contain nitrogen oxides emissions control cost, emissions reductions, and cost-effectiveness for three sizes of steam generating units, three residual oil-fired units, three distillate oil-fired units, and three natural gas-fired units. The cost-effectiveness levels of the proposed standards are generally higher than those experienced for previous standards of performance. The Agency is examining what is an appropriate cost-effectiveness cut-off level for standards development purposes and will resolve this issue before this rule is finalized. Comments are specifically requested on the reasonableness of the cost-effectiveness levels associated with the proposed standards and on the accuracy of the various cost estimates presented in Tables 9 through 14.

A major component of NO_x control costs for the proposed NO_x standards is the continuous NO_x emission monitoring system cost (see Tables 11 through 13). In developing the proposed NO_x standards, a technical assumption was made that continuous NO_x emission monitoring systems are a necessary component of all optimal NO_x emission control systems. It may be possible that for steam generating units which apply NO_x control systems based upon low excess air (LEA) technology, much of the fuel savings and NO_x emissions reduction achieved by an optimal LEA system can be achieved through the application of other less costly monitoring techniques. The Agency requests data and comments on other alternative monitoring techniques that may be applicable to steam generating units applying LEA technology.

TABLE 9.—ANNUALIZED COSTS AND INCREMENTAL COST EFFECTIVENESS OF ALTERNATIVE PM CONTROLS FOR LOW SULFUR COAL-FIRED STEAM GENERATING UNITS ($1,982) [a b c]

Steam generating unit type/size (10^6 Btu/hr)	Annualized cost ($1,000)					Emissions reduction over baseline (tpy)			Cost effectiveness ($/Ton)				
									Average			Incremental	
	Uncontrolled steam generating unit	SM	DM	SSS	FF	DM	SSS	FF	DM	SSS	FF	SSS	FF
SPRD 100	4,020	89	109	141	296	79	91	145	254	570	1,430	2,580	2,910
SPRD 150	5,670	119	148	180	402	118	138	217	245	514	1,310	2,130	2,690
SPRD 200	7,290	148	187	239	501	158	184	289	247	495	1,220	1,980	2,490
SPRD 250	8,900	177	225	286	597	197	230	361	243	474	1,160	1,860	2,370
PLVR 150	6,390	107	137	[d]380	387	177	[d]296	375	169	[d]923	750	[d]2,000	80
PLVR 250	9,520	158	207	[d]495	573	298	[d]493	624	166	[d]684	670	[d]1,460	590
PLVR 400	13,980	234	310	[d]665	837	473	[d]788	899	161	[d]534	600	[d]1,090	860

[a] Low Sulfur Coal: HHV=9600 Btu/lb; S=0.6 wt.%; Ash=5.4 wt. %.
[b] Annual Capacity Factor=60%.
[c] Key to abbreviations: SPRD=spreader stoker, PLVR=pulverized coal, SM=single mechanical collector, DM=double mechanical collector, SSS=sidestream separator, FF=fabric filter, ESP=electrostatic precipitator.
[d] Values shown are for an ESP to achieve emissions level of 0.20 lb/10^6 Btu. SSS are not applicable to pulverized coal-fired steam generating units.

TABLE 10.—ANNUALIZED COSTS AND INCREMENTAL COST EFFECTIVENESS OF ALTERNATIVE PM CONTROLS FOR WOOD- AND MUNICIPAL SOLID WASTE-FIRED STEAM GENERATING UNITS ($1,982) [a b]

Steam generating unit type/size (10^6 Btu/hr)	Annualized cost ($1,000/yr)							Reduction over baseline (tpy)					Cost effectiveness $/ton								
													Average					Incremental			
	Uncontrolled steam generating unit	SM	DM	SM/WS1	SM/WS2	ESP1	ESP2	DM	SM/WS1	SM/WS2	ESP1	ESP2	DM	WS1	WS2	ESP1	ESP2	SM/WS1	SM/WS2	ESP1	ESP2
WOOD-150	8,520	171	238	435	489			99	158	197			680	1,670	1,610			3,710	1,190		
WOOD-400	18,770	381	538			805	885	263			421	526	600			1,010	960			1,690	760
MSW-150	22,940	144	189			398	423	158			315	355	290			600	780			1,330	630
MSW-400	49,070	321	435			703	835	420			841	946	270			450	540			640	1,260

[a] Annual capacity factor=60%.
[b] Key to abbreviations: WOOD=100% wood-fired steam generating unit, MSW=100% municipal solid waste-fired steam generating unit, SM=single mechanical collector, DM=double mechanical collector, WS1=wet scrubber with 7" pressure drop, WS2=wet scrubber with 12" pressure drop, ESP1=low efficiency electrostatic precipitator, ESP2=high efficiency electrostatic precipitator.

TABLE 11.—ANNUALIZED COSTS AND COST EFFECTIVENESS OF NO_x CONTROL FOR COAL AND RESIDUAL OIL-FIRED STEAM GENERATING UNITS (1982) [a b]

Steam generating unit type/size 10^6 Btu/hr	Annualized cost ($1,000/yr)						Emissions reduction (TPY)	Cost effectiveness ($/ton)			
	Steam generating unit	Fuel savings	NO_x monitor	Other (O_2 trim, derate)	Gross (w/o fuel savings)	Net [b] (w/ fuel savings)		Net	Excluding fuel savings	Excluding NO_x monitor	Excluding fuel savings and NO_x monitor
Coal:											
SPRD-100	4,020	16.3	42.8	5.6	48.4	32.1	37	870	1,300	0	150
SPRD-150	5,670	24.4	42.8	6.9	49.7	25.3	55	460	900	0	130
SPRD-250	8,900	40.7	42.8	9.6	52.4	11.7	92	130	570	0	100
PLVR-150	6,390	24.4	42.8	33.4	76.2	51.8	126	410	600	70	260
PLVR-250	9,520	40.7	42.8	51.7	94.5	53.8	210	260	450	50	250
PLVR-400	13,980	65.1	42.8	79.2	122.0	56.9	336	170	360	40	240
Residual oil: [c]											
RES-100	4,010	55.1	42.8	29.0	71.8	16.7	48	350	1,500	0	600
RES-150	5,840	82.6	42.8	51.0	93.8	11.2	72	160	1,300	0	710

[a] Annual capacity factor=60% (coal) and 55% (residual oil).
[b] Key to abbreviations: SPRD=spreader stoker, PLVR=pulverized coal, RES=residual oil.
[c] Emission reduction based on a 0.4 wt. % nitrogen residual oil; costs assume a 7 percent derate.

TABLE 12.—ANNUALIZED COST AND COST EFFECTIVENESS OF NO_x CONTROL FOR PULVERIZED COAL- AND RESIDUAL OIL-FIRED STEAM GENERATING UNITS (1982)[a][b]

Steam generating unit type/size (10^6 Btu/hr)	Annualized cost ($1,000/yr) LEA: Fuel savings	LEA: NO_x monitor	LEA: Other (O_2 trim, etc.)	SCA[c]	Emissions reduction (tpy): LEA	Emissions reduction (tpy): SCA	Cost effectiveness ($/ton) Including fuel savings: LEA	Including fuel savings: SCA	Excluding fuel savings: LEA	Excluding fuel savings: SCA	Excluding NO_x monitor: LEA	Excluding NO_x monitor: SCA	Incremental SCA vs. LEA
Pulverized coal:													
PLVR-150	24.4	42.8	6.9	26.5	55.2	103.1	450	410	830	600		70	370
Residual oil:[d][e]													
RES-150[d]	82.6	42.8	5.0	48.0	12.8	72.3		160	3,700	1,300			770
RES-150[e]	82.6	42.8	5.0	48.0	12.8	123.0		80	3,700	760			420

[a] Annual capacity factor=60 percent for coal; annual capacity factor=55 percent for oil.
[b] Key to abbreviations: PLVR=pulverized coal; RES=residual oil; LEA=low excess air; SCA=staged combustion air.
[c] SCA technology incorporates both LEA and staged combustion (SC) technology. Costs shown for SCA are incremental costs above LEA costs.
[d] Based on a 0.4 wt. % nitrogen oil.
[e] Based on a 0.6 wt. % nitrogen oil.

TABLE 13. ANNUALIZED COST AND COST EFFECTIVENESS OF NO_x CONTROL FOR NATURAL GAS- AND DISTILLATE OIL-FIRED STEAM GENERATING UNIT ($1982)[a]

Steam generating unit type/size (10^6 Btu/hr)	Annualized cost ($1,000/yr): Uncontrolled steam generating unit	Fuel savings	LEA NO_x monitor	(Other O_2 trim, etc.)	LNB[b] staged burner	Emissions reduction (tpy): LEA	Emissions reduction (tpy): LNB	Cost Effectiveness ($/ton) Including fuel savings: LEA	Including fuel savings: LNB	Excluding fuel savings: LEA	Excluding fuel savings: LNB	Excluding NO_x monitor	Incremental LNB vs. LEA
Natural gas:													
NG-100	4,010	52.2	42.8	4.2	1.7	10	38	0	0	4,700	1,400	0	70
NG-150	5,830	78.3	42.8	5.0	1.7	15	54	0	0	3,180	820	0	40
NG-250	9,460	130.6	42.8	6.6	1.7	25	90	0	0	1,930	570	0	30
Distillate oil:													
DIST-100	4,820	68.8	42.8	4.2	1.7	22	41	0	0	2,140	1,200	0	90
DIST-150	7,060	103.3	42.8	5.0	1.7	33	61	0	0	1,450	810	0	60
DIST-250	10,820	172.1	42.8	6.6	1.7	55	102	0	0	800	500	0	40

[a] Annual capacity factor=55 percent
[b] Key to abbreviations: NG=natural gas, DIST=distillate oil, LEA=low excess air, LNB=low NO_x burner. LNB technology incorporates both LEA and staged combustion (SC) technology.

TABLE 14. ANNUALIZED COST AND COST EFFECTIVENESS OF NO_x CONTROL FOR LOW CAPACITY FACTOR (20 PERCENT) NATURAL GAS- AND DISTILLATE OIL-FIRED STEAM GENERATING UNITS ($1982)[a]

Steam generating unit type/size (10^6 Btu/hr)	Annualized cost ($1,000/yr): Fuel savings	LEA (Other O_2 trim, etc.)	LNB[b] staged burner	Emissions reduction (tpy): LEA	Emissions reduction (tpy): LNB	Cost Effectiveness ($/ton) Including fuel savings: LEA	Including fuel savings: LNB	Excluding fuel savings: LEA	Excluding fuel savings: LNB	Incremental LNB vs. LEA
Natural gas:										
NG-100	19.0	4.2	1.7	4	13	0	0	1,050	450	190
NG-150	28.5	5.0	1.7	5	20	0	0	1,000	340	110
NG-250	47.5	6.6	1.7	0	33	0	0	730	250	70
Distillate oil:										
DIST-100	25.0	4.2	1.7	8	15	0	0	530	390	240
DIST-150	37.6	5.0	1.7	12	22	0	0	420	310	170
DIST-250	62.6	6.6	1.7	20	37	0	0	330	220	100

[a] Annual capacity factor=22%
[b] Key to abbreviations: NG=Natural gas, DIST=distillate oil, LEA=low excess air, LNB=low NO_x burner. LNB technology incorporates both LEA and staged combustion technology.

List of Subjects in 40 CFR Part 60

Air pollution control, Aluminum, Ammonium sulfate plants, Asphalt, Cement industry, Coal copper, Electric power plants, Glass and glass products, Grains, Intergovernmental relations, Iron, Lead, Metals, Metallic minerals, Motor vehicles, Nitric acid plants, Paper and paper products industry, Petroleum, Phosphate, Sewage disposal, Steel sulfuric acid plants, Waste treatment and disposal, Zinc, Tires, Incorporation by reference, Can surface coating, Sulfuric acid plants, Industrial organic chemicals, Organic solvent cleaners, Fossil fuel-fired steam generators, Fiberglass insulation, Synthetic fibers.

Dated: June 7, 1984.

Alvin L. Alm,

Acting Administrator.

PART 60—STANDARDS OF PERFORMANCE FOR NEW STATIONARY SOURCES

It is proposed that 40 CFR Part 60 be amended by adding a new Subpart Db as follows:

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

Sec.

Authority.—Sec. 111 and 301(a) of the Clean Air Act, as amended [42 U.S.C. 7411, 7601(a)], and additional authority as noted below.

Subpart Db—Standards of Performance for Industrial-Commercial-Institutional Steam Generating Units

§ 60.40b Applicability and definition of affected facility.

(a) The affected facility to which this subpart applies is each industrial-commercial-institutional steam generating unit for which construction, modification, or reconstruction is commenced after June 19, 1984 and which has a heat input capacity from fuels combusted in the steam generating unit of more than 29 MW (100 million Btu/hour).

(b) Coal-fired industrial-commercial-institutional steam generating units meeting both the applicability requirements under this subpart and the applicability requirements under Subpart D (Standards of performance for fossil fuel-fired steam generators; § 60.40) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under Subpart D (§ 60.43).

(c) Oil-fired industrial-commercial-institutional steam generating units meeting both the applicability requirements under this subpart and the applicability requirements under Subpart D (Standards of performance for fossil fuel-fired steam generators; § 60.40) are subject to the nitrogen oxides standards under this subpart and the sulfur dioxide and particulate matter standards under Subpart D (§ 60.42 and § 60.43).

(d) Industrial-commercial-institutional steam generating units meeting the applicability requirements under this subpart and the applicability requirements under Subpart J (Standards of performance for petroleum refineries; § 60.104) are subject to the particulate matter and nitrogen oxides standards under this subpart and the sulfur dioxide standards under Subpart J (§ 60.104).

(e) Steam generating units meeting the applicability requirements under Subpart Da (Standards of performance for electric utility steam generating units; § 60.40a) are not subject to this subpart.

§ 60.41b Definitions.

As used in this subpart, all terms not defined herein shall have the meaning given them in the Act and in Subpart A of this part.

"Annual capacity factor" means the ratio between the actual heat input to a steam generating unit from the fuels listed in § 60.42b(a) or § 60.43b(a), as applicable, during a calendar year and the potential heat input to the steam generating unit from all fuels had it been operated for 8,760 hours at the maximum design heat input capacity.

"By-product/waste" means any substance produced during an industrial process which is not produced for the primary purpose of being combusted, but which is ultimately combusted in a steam generating unit for heat recovery or for disposal.

"Coal" means all solid fuels classified as anthracite, bituminous, subbituminous, or lignite by the American Society of Testing and Materials (ASTM Specification D 388-66). Coal-derived synthetic fuels, including but not limited to solvent refined coal, gasified coal and coal-water mixtures, are included in this definition for the purposes of this subpart.

"Combined cycle steam generating unit" means a steam generation unit in which exhaust gases from a gas turbine are introduced into a steam generating unit.

"Distillate oil" means fuel oils number 1 and 2, as defined by the American Society of Testing and Materials (ASTM burner fuel specification D 396).

"Fluidized bed combustion steam generating unit" means a steam generating unit which combusts fuel on a bed of sorbent or inert material which is suspended or fluidized by a stream of air.

"Full capacity" means operation of the steam generating unit at 90 percent or more of the maximum design heat input capacity.

"Heat input" means heat derived from combustion of fuel in a steam generating unit and does not include the heat input from preheated gases, such as gas turbine exhaust supplied to a steam generator for heat recovery.

"Heat input capacity" means the ability of a steam generating unit to combust a stated maximum amount of fuel, as determined by the physical design and characteristics of the steam generating unit.

"Industrial-commercial-institutional steam generating unit" means any steam generating unit not covered under Subpart Da (Standards of performance for electric utility steam generating units).

"Lignite" means a type of coal classified as lignite A or lignite B by the American Society of Testing and Materials (ASTM Specification D 388-66).

"Mass-feed stoker steam generating unit" means a steam generating unit where solid fuel is introduced directly into a retort or is fed directly onto a grate where it is combusted.

"Municipal-type waste" means paper, wood, yard wastes, food wastes, plastics, leather, rubber, and other combustible materials, and noncombustible materials such as glass and rock, or any mixture of these materials.

"Natural gas" means natural gas and all gaseous byproducts/wastes which contain less than 10 percent carbon monoxide (by volume).

"Oil" means a liquid fuel derived from petroleum, including distillate and residual oil.

"Pulverized coal-fired steam generating unit" means a steam generating unit in which pulverized coal is introduced into an air stream that carries the coal to the combustion chamber of the steam generating unit where it is fired in suspension.

"Residual oil" means fuel oils number 4, 5 and 6, as defined by the American Society of Testing and Materials (ASTM burner fuel specification D 396). For the purposes of this subpart, residual oil also includes all liquid by-products/wastes.

"Solid waste" means any fuel which contains more than 50 weight percent municipal-type waste or combustible material derived from municipal-type waste.

"Spreader stoker steam generating unit" means a steam generating unit in which solid fuel is introduced to the combustion zone by a mechanism that throws the fuel onto a grate from above. Combustion take place both in suspension and on the grate.

"Steam generating unit" means a device which combusts fuel to produce steam or heated water, including steam generating units which combust fuel and are part of a cogeneration system, a combined cycle system, or an incinerator with a heat recovery steam generating unit.

"Steam generating unit operating day" means a 24-hour period between 12:01 a.m. and 12:00 midnight during which any fuel is combusted in the steam generating unit. It is not necessary for fuel to be combusted continuously for the entire 24-hour period.

"Wet scrubber system" means any emission control device which uses an aqueous stream or slurry injected into the scrubbing chamber to control emissions of particulate matter or sulfur dioxide.

"Wood" means wood, wood residue, bark, or any derivative fuel or residue thereof, in any form, including but not limited to, sawdust, sanderdust, wood chips, scraps, slabs, millings, shavings, and processed pellets made from wood or other forest residues.

§ 60.42b Standards for particulate matter.

(a) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator of an affected facility which combusts coal, wood, or solid waste, or simultaneously combusts mixtures of these fuels with or without other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases which contain particulate matter in excess of the following emission limits, except as provided under paragraph (b) of this section:

Steam generating unit fuel type	Particulate matter emission limit nanograms per joule heat input (lb/million Btu heat input)
(1) Coal	22 (0.05)
(2) Wood or solid waste	43 (0.10)
(3) Mixtures including wood, coal, or solid waste, with or without other fuels, as provided under paragraph (c) of this section	43 (0.10)

(b) On and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator of an affected facility which has a heat input capacity of 73 MW (250 million Btu/hour) or less and which combusts coal, wood, or solid waste, or simultaneously combusts mixtures of these fuels with or without other fuels and which has an annual capacity factor for coal, wood, or solid waste, or any mixtures of these fuels of 30 percent (0.30) or less, and who has a Federal, State, or local permit which limits operation of the facility to an annual capacity factor of 30 percent (0.30) or less for these fuels or fuel mixtures, shall cause to be discharged into the atmosphere from that facility any gases which contain particulate matter in excess of 86 nanograms per joule (0.20 lb/million Btu) heat input.

(c) Except as provided under paragraph (b) of this section, on and after the date on which the performance test required to be conducted under § 60.8 is completed, no owner or operator of an affected facility which combusts coal with wood, solid waste or other fuels, which has an annual capacity factor for wood, solid waste or other fuels of more than 5 percent (0.05), and which is subject to a Federal, State or local permit which specifies that during the operation of the affected facility, the affected facility will achieve an annual capacity factor for wood, solid waste, or other fuels of more than 5 percent (0.05), shall cause to be discharged from that affected facility any gases which contain particulate matter in excess of 43 nanograms per joule (0.10 lb/million Btu) heat input, as required by paragraph (a)(3) of this section. An affected facility which combusts coal with wood, solid waste or other fuels and which either has an annual capacity factor for wood, solid waste or other fuels of 5 percent (0.05) or less, or which is not subject to a Federal, State or local permit which specifies that during the operation of the affected facility, the affected facility will achieve an annual capacity factor for wood, solid waste, or other fuels of more than 5 percent (0.05), is subject to the 22 nanograms per joule (0.05 lb/million Btu) heat input emission limit under paragraph (a)(1) of this section.

(d) For the purposes of this section, the annual capacity factor shall be determined by dividing the actual heat input to the steam generating unit during the calendar year from the combustion of coal, wood, or solid waste, or any mixture of these fuels, by the potential heat input from all fuels if the steam generating unit had been operated for 8,760 hours at the maximum design heat input capacity.

(e) On and after the date the particulate matter performance test required to be conducted under § 60.8 is completed, no owner or operator of an affected facility subject to the particulate matter emission limits under paragraphs (a) or (b) of this section shall cause to be discharged into the atmosphere any gases which exhibit greater than 20 percent opacity (6-minute average).

§ 60.43b Standards for nitrogen oxides.

(a) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator of an affected facility subject to the provisions of this section which combusts coal, oil, or natural gas, or simultaneously combusts mixtures of these fuels with or without other fuels, shall cause to be discharged into the atmosphere from that affected facility any gases which contain nitrogen oxides in excess of the following emission limits, except as provided under paragraph (e) of this section:

Fuel/steam generating unit type	Nitrogen oxide emission limits nanograms per joule heat input (lb/million Btu heat input)
(1) Natural gas and distillate oil	43 (0.10).
(2) Residual oil:	
(i) 0.35 weight percent nitrogen or less.	129 (0.30).
(ii) Greater than 0.35 weight percent nitrogen.	172 (0.40).
(3) Coal (other than lignite):	
(i) Mass-feed stoker	215 (0.50).
(ii) Spreader stoker and fluidized bed combustion.	258 (0.60).
(iii) Pulverized coal	301 (0.70).
(4) Lignite, all units except (5)	258 (0.60).
(5) Lignite mined in North Dakota, South Dakota, or Montana and combusted in a slag tap furnace.	340 (0.80).
(6) Mixtures of natural gas or distillate oil with wood or solid waste.	129 (0.30).
(7) Mixtures of coal, oil, or natural gas with wood, solid waste, or any other fuel (other than (5)).	Applicable emission limit for coal, oil, or natural gas as listed above or as determined pursuant to paragraph (b).

(b) On and after the date on which the initial performance test required to be conducted under § 60.8 is completed, no owner or operator of an affected facility which simultaneously combusts mixtures of coal, oil, or natural gas, with or without any other fuel, shall cause to be discharged into the atmosphere from that affected facility any gases which contain nitrogen oxides in excess of a limit determined by use of the following formula:

$$E_{NO_x}=(43Hs+129Hu+172Hv+215Hw+258Hx+301Hy+340Hz)/Ht$$

where:

E_{NO_x} is the nitrogen oxides emission limit (nanograms per joule).
Hs is the heat input from combustion of natural gas or oil subject to the 43 nanogram per joule standard.
Hu is the heat input from combustion of oil or mixtures of natural gas with wood or solid waste subject to the 129 nanogram per joule standard.
Hv is the heat input from combustion of oil subject to the 172 nanogram per joule standard.
Hw is the heat input from combustion of coal subject to the 215 nanogram per joule standard.
Hx is the heat input from combustion of coal subject to the 258 nanogram per joule standard.
Hy is the heat input from combustion of pulverized coal subject to the 301 nanogram per joule standard.
Hz is the heat input from combustion of lignite subject to the 340 nanogram per joule standard.
Ht is the total heat input to the steam generating unit from combustion of coal, oil, or natural gas.

(c) On and after the date on which the performance test required to be conducted under § 60.8 is completed, any owner or operator of an affected facility which simultaneously combusts coal, oil or natural gas in a mixture with a liquid by-product/waste or with a toxic, corrosive or reactive hazardous waste (as defined by 40 CFR Part 261) may petition the Administrator to establish a nitrogen oxides emission limit which shall apply specifically to that affected facility when the liquid by-product waste or the hazardous waste is combusted. The petition submitted by the owner or operator of the affected facility shall include sufficient and appropriate data on nitrogen oxides emissions from the affected facility, waste destruction efficiencies, waste composition (including nitrogen content), and combustion conditions to allow the Administrator to determine if the affected facility is able to comply with the nitrogen oxides emission limits under paragraphs (a) and (b) of this section when coal, oil or natural gas are combusted in the steam generating unit, but is unable to comply with the emission limits in paragraphs (a) and (b) of this section when:

(1) Liquid by-product/waste with a high nitrogen content is combusted under the same combustion conditions which were used to achieve compliance with the emission limits under paragraphs (a) and (b) of this section when coal, oil, or natural gas was fired; or

(2) Toxic, corrosive, or reactive hazardous waste is combusted in the affected facility, pursuant to thermal destruction efficiency requirements for hazardous waste as specified in an applicable Federal, State or local permit which requires combustion conditions which preclude compliance with the nitrogen oxides emission limits under paragraphs (a) and (b) of this section.

If a site specific nitrogen oxide emission limit is approved by the Administrator, it will be established at the nitrogen oxide emission level achieved when the affected facility was firing liquid by-product/waste at combustion conditions which were used to achieve compliance with the emision limits under paragraph (a) or (b) of this section when coal, oil or natural gas is fired, or at the nitrogen oxide emission level achieved when toxic, corrosive, or reactive hazardous waste is combusted in the affected facility during a test burn to determine the thermal destruction efficiency of hazardous waste as specified in an applicable Federal, State, or local permit which requires thermal destruction of hazardous waste.

(d) Modification of a facility, as defined in § 60.15, shall not, by itself, subject the facility to the requirements of this section limiting nitrogen oxides emissions.

(e) Any affected facility which has an annual capacity utilization factor for coal, oil, or natural gas or any mixture of these fuels of 5 percent (0.05) or less, and which is subject to a Federal, State, or local permit which limits operation of the facility to an annual capacity factor of 5 percent (0.05) or less for these fuels is not subject to the requirements of this section.

§ 60.44b Compliance and performance testing.

(a) The particulate matter emission standards under § 60.42b and the nitrogen oxides emission standards under § 60.42b apply at all times except during periods of startup, shutdown, or malfunction.

(b) Compliance with the particulate matter emission standards under § 60.42b shall be determined through performance testing as described in paragraph (d) of this section.

(c) Compliance with the nitrogen oxides emission limits under § 60.43b shall be determined through performance testing as described in paragraph (e)(1) or (e)(2) of this section, as applicable.

(d) The following procedures and reference methods are used to determine compliance with the standards for particulate matter emissions under § 60.42b.

(1) Reference Method 3 is used for gas analysis when applying Reference Method 5 or Reference Method 17

(2) Reference Method 5 or Reference Method 17 shall be used to measure the concentration of particulate matter and the associated moisture content as follows:

(i) Reference Method 5 shall be used at affected facilities without wet scrubber systems; and

(ii) Reference Method 17 shall be used at facilities with or without wet scrubber systems provided that the stack gas temperature at the sampling location does not exceed an average temperature of 160°C (320°F).

(3) Reference Method 1 is used to select the sampling site and the number of traverse sampling points. The sampling time for each run is at least 120 minutes and the minimum sampling volume is 1.7 dscm (60 dscf) except that smaller sampling times or volumes, when necessitated by process variables or other factors, may be approved by the Administrator.

(4) For Reference Method 5 the temperature of the sample gas in the probe and filter holder is monitored and is maintained at 160°C (320°F).

(5) For determination of particulate emissions, the oxygen or carbon dioxide sample is obtained simultaneously with each run of Reference Method 5 or Reference Method 17 by traversing the duct at the sampling location.

(6) For each run using Reference Method 5 or Reference Method 17 the emission rate expressed in nanograms per joule heat input is determined using:

(i) The oxygen or carbon dioxide measurements and particulate matter measurements obtained under this section,

(ii) The dry basis F_c factor, and

(iii) The dry basis emission rate calculation procedure contained in Reference Method 19 (Appendix A).

(7) Reference Method 9 is used for determining the opacity of stack emissions.

(e) The following procedures are used in performance testing to determine compliance with the emission limits for nitrogen oxides required under § 60.43b:

(1) For affected facilities having an annual capacity factor for the fuels listed in § 60.43b(a) of 30 percent (0.30) or less, the owner or operator shall conduct a 30-day performance test using a chemiluminescent nitrogen oxides monitor following the procedures prescribed in § 60.8;

(2) For affected facilities having an annual capacity factor for the fuels listed in § 60.43b(a) greater than 30 percent (0.30), the owner or operator shall conduct the performance test as required under § 60.8 using the continuous system for monitoring nitrogen oxides under § 60.45b(b). The nitrogen oxides emissions from the steam generating unit shall be monitored for 30 successive steam generating unit operating days after initial startup and a 30-day average nitrogen oxide emission rate is calculated based on the hourly nitrogen oxide emissions recorded by the monitoring system for the preceding 720 hours of boiler operation.

§ 60.45b Emission monitoring.

(a) The owner or operator of an affected facility subject to the opacity standard under § 60.42b shall install, calibrate, maintain and operate a continuous monitoring system for measuring the opacity of emissions discharged to the atmosphere and record the output of the system.

(b) Except as provided in paragraph (g) of this section, the owner or operator of an affected facility subject to the nitrogen oxides standard of § 60.43b shall install, calibrate, maintain, and operate a continuous monitoring system for measuring nitrogen oxides emissions discharged to the atmosphere and record the output of the system.

(c) The continuous monitoring systems required under paragraph (b) of this section shall be operated and data recorded during all periods of operation of the affected facility, including periods of startup, shutdown, or malfunction, except for continuous monitoring system breakdowns, repairs, calibration checks, and zero and span adjustments.

(d) The 1-hour average nitrogen oxide emission rates measured by the continuous nitrogen oxides monitor required by paragraph (b) of this section and required under § 60.13(h) shall be expressed in nanograms per joule or lb/million Btu heat input and shall be used to calculate the average emission rates under § 60.43b. The 1-hour averages shall be calculated using the data points required under § 60.13(b). At least 4 data points must be used to calculate each 1-hour average.

(e) The procedures under § 60.13 shall be followed for installation, evaluation, and operation of the continuous monitoring systems.

(1) For affected facilities burning coal, wood or solid waste, the span value for a continuous monitoring system for measuring opacity shall be between 60 and 80 percent.

(2) For affected facilities burning coal, oil, or natural gas, the span value for nitrogen oxides is determined as follows:

Fossil fuel	Span values for nitrogen oxides (ppm)
Natural gas	500
Oil	500
Coal	1,000
Combination	500 (x+y)+1,000z

where:
x is the fraction of total heat input derived from natural gas,
y is the fraction of total heat input derived from oil, and
z is the fraction of total heat input derived from coal

(3) All span values computed under paragraph (h)(2) of this section for burning combinations of regulated fuels are rounded to the nearest 500 ppm.

(f) If emission data are not available for more than one successive steam generating unit operating day the owner or operator of the affected facility shall initiate servicing of the continuous emission monitoring system within 5 calendar days and return the monitor to operation in no more than 15 calendar days from initial data loss. (Sec. 114, Clean Air Act as amended (42 U.S.C. 7414).)

(g) The owner or operator of an affected facility subject to the nitrogen oxides standard of § 60.43b and which is subject to a Federal, State or local permit requirement which limits operation of the facility to an annual capacity factor of 30 percent (0.30) or less for coal, oil, or natural gas shall:

(1) Comply with the provisions of paragraph (b) of this section, or

(2) Monitor steam generating unit operation conditions specified in a plan submitted under § 60.46b(c).

§ 60.46b Reporting and recordkeeping requirements.

(a) The owner or operator of each affected facility shall submit notification of the date of initial startup, as provided by § 60.11. This notification shall include:

(1) Identification of the fuels to be combusted in the affected facility, and

(2) The design heat input capacity and the annual capacity factor at which the owner or operator anticipates operating the facility, and, if applicable, a copy of any Federal, State or local permit which limits the annual capacity factor for any fuel or mixture of fuels listed in § 60.42b(a) to 30 percent (0.30) or less, or for any fuel or mixture of fuels listed in § 60.43b(a) to 5 percent (0.05) or less.

(b) For facilities subject to the particulate matter and nitrogen oxides emission limits under § 60.42b and § 60.43b, the performance test data from the initial performance test and the performance evaluation of the continuous monitors shall be submitted to the Administrator by the owner or operator of the affected facility.

(c) The owner or operator of each affected facility subject to the nitrogen oxides standard of § 60.43b who seeks to demonstrate compliance with those standards through the monitoring of steam generating unit operating conditions pursuant to the provisions of § 60.45b(g)(2) shall submit to the Administrator for approval a plan which identifies the operating conditions to be monitored under § 60.45b(g)(2) and the records to be maintained under § 60.45b(i). This plan shall be submitted to the Administrator for approval with the notification of initial startup required under paragraph (a) of this section. The plan shall:

(1) Identify the specific operating conditions to be monitored (and, if appropriate, the variation in these operating conditions with steam generating unit load over the range of 30 to 100 percent of the maximum design heat input capacity of the steam generating unit) which are consistent with maintaining nitrogen oxides emissions below the limits included in § 60.43b. Steam generating unit operating conditions include, but are not limited to, degree of staged combustion (i.e., the ratio of primary air to secondary and/or tertiary air) and the level of excess air (i.e., flue gas oxygen level).

(2) Include the data and information which the owner or operator used to identify these operating conditions and the relationship between these operating conditions and nitrogen oxides emissions; and

(3) Identify how these operating conditions, including steam generating unit load, will be monitored under § 60.45b(g) on an hourly basis by the owner or operator during the period of operation of the steam generating unit, and the type and format of the records of these operating conditions, including steam generating unit load, that will be maintained by the owner or operator under § 60.46b(i).

The Administrator shall approve or disapprove of the plan within 45 calendar days following the submission of the plan. Following approval of the plan, the owner or operator shall maintain records of the operating conditions, including steam generating unit load, identified in the plan.

(d) The owner or operator of an affected facility shall record and maintain records of the amounts of all fuels fired each calendar quarter and calculate the annual capacity factor for coal, oil, natural gas, wood and solid waste.

(e) For facilities firing residual oil and subject to § 60.43b(a)(2)(ii), the owner or operator shall maintain records of the fuel oil nitrogen content fired in the steam generating unit and calculate the average fuel nitrogen content on a per calendar quarter basis. Fuel specification data obtained from fuel suppliers may be used.

(f) For facilities subject to the opacity standard under § 60.42b, the owner or operator shall maintain records of opacity.

(g) For facilities subject to nitrogen oxides standards under § 60.43b, the owner or operator shall maintain records of the following information for each steam generating unit operating day:

(1) Calendar date.

(2) The average hourly nitrogen oxides emission rates (nanograms per joule or lb per million Btu heat input).

(3) The average nitrogen oxide emission rates (nanogram per joule or lb per million Btu heat input) calculated at the end of the steam generating unit operating day from the average hourly nitrogen oxide emission rates for the preceding 720 hours of steam generating unit operation.

(4) Identification of the steam generating unit operating days when the average nitrogen oxide emission rates determined under paragraph (g)(3) are in excess of the nitrogen oxides emissions standards under § 60.43b, with the reasons for such excess emissions as well as a description of corrective actions taken.

(5) Identification of the steam generating unit operating days for which

pollutant data have not been obtained, including reasons for not obtaining sufficient data and a description of corrective actions taken.

(6) Identification of the times when emissions data have been excluded from the calculation of average emission rates because of startup, shutdown, malfunction, or other reasons, and the reasons for excluding data at times other than startup, shutdown, or malfunction.

(7) Identification of "F" factor used for calculations, method of determination, and type of fuel combusted.

(8) Identification of the times when the pollutant concentration exceeded full span of the continuous monitoring system.

(9) Description of any modifications to the continuous monitoring system which could affect the ability of the continuous monitoring system to comply with Performance Specifications 2 or 3.

(h) The owner of operator of any affected facility subject to the opacity standards under § 60.43b(e) or the nitrogen oxides emissions limits under § 60.43b shall submit a report for each semiannual period during which excess emissions occur. No excess emissions report shall be submitted for any semiannual reporting period during which the affected facility did not exceed either the opacity standards under § 60.42b(e) or the nitrogen oxides emissions standards under § 60.43b, notwithstanding the provisions of § 60.7(c)(4).

(i) All records required under this section shall be maintained by the owner or operator of the affected facility for a period of 2 years following the date of such record.

(Sec. 114, Clean Air Act as amended (42 U.S.C. 7414))

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