[JOINT COMMITTEE PRINT]

DESCRIPTION OF H.R. 2497 (SULFUR AND NITROGEN EMISSIONS TAX ACT OF 1987)

SCHEDULED FOR A HEARING

BEFORE THE

HOUSE COMMITTEE ON WAYS AND MEANS

ON SEPTEMBER 9, 1987

PREPARED BY THE STAFF

OF THE

JOINT COMMITTEE ON TAXATION

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CONTENTS

	Page
INTRODUCTION	1
I. BACKGROUND	2
II. SUMMARY OF H.R. 2497	5
III. PRESENT LAW	6
A. Environmental Excise Taxes	6
B. Prior Excise Tax on Hazardous Waste	12
IV. DESCRIPTION OF H.R. 2497 (AND H.R. 2498)	13
A. Tax and Trust Fund Provisions (H.R. 2497 and Title I of H.R. 2498)	13
B. Acid Deposition Control Assistance Program (Title II of H.R. 2498)	16
V. ISSUES RELATING TO THE TAXATION OF EMISSIONS	20
A. Market vs. Regulatory Approaches to Reducing Emissions	20
B. Incentive Effects of Emissions Taxes	21
C. Appropriate Rate of Tax	22
D. Regional Effects	24
E. Effects on the Electric Utility Industry	27
F. Effects on the Coal Industry	27
G. Effects on Other Industries	28
H. Administrative Concerns	30
I. Experience with Emissions Taxes	31

INTRODUCTION

The House Committee on Ways and Means has scheduled a public hearing on September 9, 1987, on H.R. 2497, "Sulfur and Nitrogen Emissions Tax Act of 1987" (introduced by Messrs. Gregg, Downey, Frenzel, and Jeffords). (H.R. 2498, referred jointly to the Committees on Ways and Means and Energy and Commerce contains identical tax and essentially the same trust fund provisions (Title I), as well as amendments to the Clean Air Act that would establish an Acid Deposition Control Assistance Program (Title II).)

This pamphlet,[1] prepared by the staff of the Joint Committee on Taxation in connection with the hearing, provides a description of the provisions of H.R. 2497 and H.R. 2498. Part I of the pamphlet provides background information on acid deposition and present air pollution control policies. Part II is a summary of H.R. 2497. Part III of the pamphlet is a description of present-law taxes on certain substances that may cause environmental pollution. Part IV is a description of the bills, and Part V is a discussion of tax policy issues relating to bills.

[1] This pamphlet may be cited as follows: Joint Committee on Taxation, *Description of H.R. 2497 (Sulfur and Nitrogen Emissions Tax Act of 1987)* (JCS-20-87), August 31, 1987.

I. BACKGROUND

Clear Air Act

In 1970, through the passage of the Clean Air Act, Congress initiated the Federal regulation of sulfur dioxide, nitrogen oxides, and other emissions. The Clean Air Act (last amended substantially in 1977) established national ambient air quality standards and required the development of State Implementation Plans ("SIPs") to achieve these standards. SIP standards may vary within and among the States depending upon local conditions.

The Clean Air Act also empowered the Federal Government to establish uniform standards for all new sources of emissions. These New Source Performance Standards ("NSPS") limit the amount of air pollution from new or modified facilities. States are permitted to set stricter emissions standards for new facilities.

The original NSPS required any coal-fired electric utility built after 1971 to emit no more than 1.2 pounds of sulfur dioxide per million British thermal units ("Btu's") [2] for any type of coal consumed; 0.7 pounds of nitrogen oxides per million Btu's for anthracite, bituminous and subbituminous coals; and 0.6 pounds of nitrogen oxides per million Btu's for lignite. Different standards applied to industrial boilers. For example, the 1971 NSPS required coal-fired industrial boilers to meet the 1.2 pound sulfur standard only if the boiler had a capacity of 250 million Btu's or more. Smaller boilers were left to State regulation through SIPs. For oil- and gas-fired boilers, the 1971 NSPS mandated a maximum of 0.8 pounds per million Btu's for sulfur dioxide and 0.2 pounds per million Btu's for nitrogen oxides. The NSPS also established limits on particulate emissions.

Plants built since 1979 must meet stricter NSPS. For coal-fired electric utilities, the sulfur dioxide limit mandates either (1) at least a 90-percent reduction of the potential sulfur in the coal and in no circumstances more than 1.2 pounds per million Btu's, or (2) at least a 70-percent reduction and no more than 0.6 pounds per million Btu's. For nitrogen oxides, the limit is 0.6 pounds per million Btu's for all types of coal. These standards also apply to new industrial boilers which have a capacity of at least 100 million Btu's. As a practical matter, these standards mandate the installation of flu gas desulfurizers ("FGDs" or "scrubbers") because the percentage reduction requirements will be the limiting factor in almost all circumstances.

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[2] A Btu is a measure of energy content. One Btu is the amount of energy needed to raise the temperature of one pound of water by one degree Fahrenheit. One million Btu's are contained in 975 cubic feet of natural gas, 7.2 gallons of crude oil, 80 pounds of coal, or 293 kilowatt-hours of electricity.

Acid deposition

As the sulfur dioxides, nitrogen oxides, and hydrocarbons produced during the combustion of fossil fuels are carried away from their sources, they can be transformed through complex chemical processes into secondary pollutants—ozone and airborne fine particles such as sulfate and nitrate. Acid deposition results when sulfur dioxides, nitrogen oxides, and their transformed products return from the atmosphere to the earth's surface.

Precipitation can absorb these particles and gases, and they can return to earth in rain, snow, fog, or dew. The dry particles and gases can also return to earth without precipitation. When acid deposition occurs in wet form, it is called "acid precipitation" or "acid rain," so-called because the precipitation is more acidic than normal. In the eastern United States, on average, deposition of sulfur compounds occurs equally in wet and dry forms.[3]

Analysis of the causes of acid deposition and its effects is a complex problem. For example, in the winter the formation of sulfuric acid from sulfur dioxide is limited by oxidant availability, clouding the link between sulfur dioxide emissions and acid deposition.[4] The scientific evidence, while not definitive, suggests that acid deposition damages lakes and streams, kills fish, may reduce timber and crop yields, and may damage property.[5]

Acid Precipitation Act

Recognizing the complex nature of the acid deposition issue, Congress enacted the Acid Precipitation Act of 1980 to establish an interagency task force on acid precipitation. The National Oceanographic and Atmospheric Administration ("NOAA"), the Environmental Protection Agency ("EPA"), and the Department of Agriculture jointly chair the task force. The task force includes the Department of Energy, the Department of the Interior, the Department of State, the National Science Foundation, the Tennessee Valley Authority, the Council on Environmental Quality, the Department of Health and Human Services, and the Argonne, Brookhaven, Oak Ridge, and Pacific Northwest National Laboratories. NOAA is the director of research.

One of the task force's responsibilities is to plan and implement a ten-year National Acid Precipitation Assessment Program ("NAPAP"). NAPAP consists of over 300 interrelated research projects in 10 major areas: Natural Sources; Man-Made Sources; Atmospheric Processes; Deposition Monitoring; Aquatic Effects; Terrestrial Effects; Effects on Materials and Cultural Resources; Control Technologies; Assessments; and International Activities.

U.S.-Canadian Report

At present there is no regulatory program specifically enacted to control acid rain.[6] In 1985, President Reagan and Prime Minister

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[3] U.S. Congress, Office of Technology Assessment, *Acid Rain and Transported Pollutants: Implication for Public Policy,* June 1984 (hereinafter referred to as OTA, "Acid Rain.")

[4] The National Acid Precipitation Assessment Program, "1986 Annual Report."

[5] OTA, "Acid Rain."

[6] For a review of acid rain bills before the Congress, see John E. Blodgett and Larry Parker, "House Acid Rain Bills in the 100th Congress: Comparison of the Major Provisions of H.R. 1664,

Continued

Mulroney of Canada commissioned a special study of the acid rain issue. The report delivered on January 8, 1986, concluded that acid rain is a serious environmental problem that warrants increased effort to control the sources of pollution which cause acid deposition. On March 19, 1987, President Reagan and Prime Minister Mulroney issued a joint statement endorsing the findings of the report and made a commitment to implement its findings.

H.R. 1679, H.R. 2497/H.R. 2498 and H.R. 2666," Congressional Research Service, July 10, 1987, 87-604 ENR; and Larry Parker and John E. Blodgett, "Senate Acid Rain Bills in the 100th Congress: Comparison of the Major Provisions of S. 95, S. 300, S. 316, S. 321, and S. 1123," Congressional Research Service, July 10, 1987, 87-605 ENR.

II. SUMMARY OF H.R. 2497

H.R. 2497 would impose an excise tax on the amount of sulfur dioxide and nitrogen oxides that are discharged into the atmosphere by large steam-generating boilers and furnaces. The rate of tax imposed by H.R. 2497 would increase as the level of emissions per million Btu's of energy produced by a boiler or furnace increased. Thus, those boilers and furnaces that produce the greatest rate of emission per million Btu's of energy produced would pay the highest rate of tax. The tax would be phased in over a 3-year period and the rates would be adjusted for inflation after 1990.

A credit against the excise tax equal to 25 percent of the cost of pollution control equipment would be allowed ratably over a 10-year period. In addition, the excise tax would be fully deductible for Federal income tax purposes. An amount equivalent to the receipts from the excise tax would be appropriated to a trust fund for the purpose of reducing the amount of sulfur dioxide and nitrogen oxides emitted into the atmosphere.

III. PRESENT LAW

A. Environmental Excise Taxes

In general

Present law does not impose an excise tax on the amount of sulfur dioxide, nitrogen oxides, or other pollutants discharged into the environment. Excise taxes are imposed under present law with respect to certain substances, such as crude oil, feedstock chemicals, and chemical derivatives, that may cause environmental pollution. Receipts from these excise taxes are appropriated to trust funds to pay costs incurred in the cleanup of hazardous wastes.

Hazardous substance superfund taxes

Receipts from a petroleum tax, a tax on feedstock chemicals, and a tax (effective January 1, 1989) on certain imported substances derived from taxable feedstock chemicals are deposited into a trust fund known as the Hazardous Substance Superfund ("Superfund") to pay for the cleanup of hazardous waste sites.

Petroleum tax

Present law (Code sec. 4611) imposes an excise tax of 8.2 cents per barrel on domestic crude oil and 11.7 cents per barrel on imported petroleum products (including imported crude oil). The tax on domestic crude oil is imposed on the operator of any United States refinery receiving such crude oil, while the tax on imported petroleum products is imposed on the person entering the product into the United States for consumption, use, or warehousing. If domestic crude oil is used in, or exported from, the United States before imposition of the petroleum tax, the tax is imposed on the user or exporter of the oil.

Domestic crude oil subject to tax includes crude oil condensate and natural gasoline, but not other natural gas liquids. Taxable crude oil does not include oil used for extraction purposes on the premises from which it was produced, such as for powerhouse fuel or for reinjection as part of a tertiary recovery process. In addition, taxable crude oil does not include synthetic petroleum (e.g., shale oil, liquids from coal, tar sands, biomass, or refined oil).

Petroleum products that are subject to tax upon being entered into the United States include crude oil, crude oil condensate, natural and refined gasoline, refined and residual oil, and any other hydrocarbon product derived from crude oil or natural gasoline that enters the United States in liquid form. For purposes of determining whether crude oil or petroleum products (and chemicals subject to the feedstock tax) have been produced in, entered into, or exported from the United States, the term United States means the 50 States, the District of Columbia, Puerto Rico, the Northern Mar-

iana Islands, the Trust Territory of the Pacific Islands, and any possession of the United States. The United States also includes the outer continental shelf areas and foreign trade zones located within the United States.

There is no exception from the tax for bonded petroleum products or for sales to, or use by, the Federal Government, a State or local government, or a tax-exempt organization. Revenues from the petroleum tax are not paid to Puerto Rico or the Virgin Islands under the cover-over provisions of section 7652 of the Code.

Present law specifies that the petroleum tax is to be imposed only once with respect to any petroleum product. Thus, a person who otherwise would be liable for the tax may avoid payment by establishing that the tax already has been imposed with respect to that product.

The petroleum tax is scheduled to expire on December 31, 1991. The tax will terminate earlier than that date if cumulative Superfund tax receipts after December 31, 1986, equal or exceed $6.65 billion. In addition, if (1) on December 31, 1989, or December 31, 1990, the unobligated balance of the Superfund exceeds $3.5 billion, and (2) the Secretary of the Treasury, in consultation with the Administrator of the EPA, determines that such unobligated balance will exceed $3.5 billion on December 31 of the next following calendar year (if no Superfund taxes are imposed during the intervening calendar year), then no tax is to be imposed during the intervening calendar year.

Tax on feedstock chemicals

Present law (Code sec. 4661) imposes an excise tax on the sale or use of 42 specified organic and inorganic chemicals ("feedstock chemicals") by the manufacturer, producer, or importer thereof. These chemicals generally are hazardous substances or may create hazardous products or wastes when used. The tax is imposed on chemicals manufactured in the United States or entered into the United States for consumption, use, or warehousing.

The tax rates are specified per ton of taxable chemical and vary from 22 cents to $4.87 per ton. In the case of a taxable chemical that is a gas (e.g., methane), the tax is imposed on the number of cubic feet of gas that is equivalent to 2,000 pounds on the basis of molecular weight. (See Table 1 for a list of chemicals and applicable tax rates under present law.)

Table 1.—Present Law Excise Tax on Feedstock Chemicals

[Dollars per ton]

Chemical	Tax rate
Organic substances:	
Acetylene	4.87
Benzene	4.87
Butadiene	4.87
Butane	4.87
Butylene	4.87
Ethylene	4.87
Methane	3.44
Napthalene	4.87
Propylene	4.87
Toluene	4.87
Xylene [1]	4.87
Inorganic substances:	
Ammonia	2.64
Antimony	4.45
Antimony trioxide	3.75
Arsenic	4.45
Arsenic trioxide	3.41
Barium sulfide	2.30
Bromine	4.45
Cadmium	4.45
Chlorine	2.70
Chromite	1.52
Chromium	4.45
Cobalt	4.45
Cupric oxide	3.59
Cupric sulfate	1.87
Cuprous oxide	3.97
Hydrochloric acid	.29
Hydrogen fluoride	4.23
Lead oxide	4.14
Mercury	4.45
Nickel	4.45
Nitric acid	.24
Phosphorous	4.45
Potassium dichromate	1.69
Potassium hydroxide	.22
Sodium dichromate	1.87
Sodium hydroxide	.28
Stannic chloride	2.12
Stannous chloride	2.85
Sulfuric acid	.26
Zinc chloride	2.22
Zinc sulfate	1.90

[1] For periods before 1992, the tax rate for xylene is $10.13.

Present law provides exceptions to the feedstock chemical tax for:

(1) methane and butane that is used as fuel;

(2) nitric acid, sulfuric acid, ammonia, and methane used to produce ammonia if such chemicals are used to produce fertilizer or are directly applied as fertilizer (or are sold for ultimate use as fertilizer or to produce fertilizer);

(3) sulfuric acid that is produced solely as a by-product of (and on the same site as) air pollution control equipment;

(4) any chemical to the extent derived from coal;

(5) petrochemicals used to manufacture or produce motor fuel, diesel fuel, aviation fuel, or jet fuel;

(6) barium sulfide, cupric sulfate, cupric oxide, cuprous oxide, lead oxide, zinc chloride, and zinc sulfate that exists in transitory form in the process of refining nontaxable metal ores or compounds into other (or purer) nontaxable compounds;

(7) nitric acid, sulfuric acid, ammonia, and methane used to produce ammonia if such chemicals are used (or sold for ultimate use) to produce animal feed;

(8) chromium, cobalt, or nickel that is recycled within the United States, but only if the recycling occurs at a site during a period that corrective action is not required at such site under the Solid Waste Disposal Act or the Comprehensive Environmental Response, Compensation, and Liability Act of 1980; and

(9) any organic taxable chemical while the chemical is part of an intermediate hydrocarbon stream that contains a mixture of organic taxable feedstock chemicals.

In addition to these exceptions for specific taxable chemicals, present law provides an exception for all feedstock chemicals that are sold by a manufacturer or producer for export or for resale by the purchaser to a second purchaser for export. If a tax is paid on a chemical and subsequently the chemical (or beginning January 1, 1989, a taxable derivative listed below in Table 2 that is manufactured from the chemical) is exported by any person, a credit or refund of the tax (without interest) is allowed to the person that paid the tax. Present law does not contain an exception to the feedstock chemical tax for sales to, or use by, the Federal Government, a State or local government, or a tax-exempt organization.

Under present law, if a taxpayer uses a taxable chemical prior to any sale, the tax is imposed as if the chemical had been sold. When a taxable chemical is used to manufacture or produce a second taxable chemical, an amount equal to the tax paid on the first chemical is allowed as a credit or refund (without interest) to the manufacturer or producer of the second chemical (but not in an amount exceeding the tax imposed on the second chemical). Thus, the imposition of tax more than once on the same substance is avoided.

The tax on feedstock chemicals is scheduled to expire on December 31, 1991. The tax may be terminated or suspended earlier than that date under the same conditions as the petroleum tax (described above).

Tax on imported chemical derivatives

Present law (Code sec. 4671) imposes an excise tax on the sale or use of certain imported chemical derivatives by the importer of the

76-562 0 - 87 - 2

chemical derivative. The tax is effective for imports of chemical derivatives on or after January 1, 1989.

The amount of tax imposed on an imported chemical derivative is the amount of tax that would have been imposed by the feedstock chemical tax on the taxable chemicals used as materials in the production of such derivative if the taxable chemicals had been sold in the United States for an equivalent use. If the importer does not furnish sufficient information (at such time and manner as the Secretary of Treasury may require), the amount of tax is 5 percent of the customs value of the imported chemical derivative.

Under present law, a chemical derivative must be listed by the Secretary of the Treasury in order to be subject to tax. The statute contains an initial list of 49 chemical derivatives that are subject to the excise tax. (See Table 2 for the initial list of chemical derivatives.)

Table 2.—Initial List of Taxable Imported Chemical Derivatives

Taxable substance
Cumene
Styrene
Ammonium nitrate
Nickel oxide
Isopropyl alcohol
Ethylene glycol
Vinyl chloride
Polyethylene resins, total
Polybutadiene
Styrene-butadiene, latex
Styrene-butadiene, snpf
Synthetic rubber, not containing fillers
Urea
Ferronickel
Ferrochromium nov 3 pct.
Ferrochrome nov 3 pct. carbon
Unwrought nickel
Nickel waste and scrap
Wrought nickel rods and wire
Nickel powders
Phenolic resins
Polyvinylchloride resins
Polystyrene resins and copolymers
Ethyl alcohol for nonbeverage use
Ethylbenzene
Methylene chloride
Polypropylene
Propylene glycol
Formaldehyde
Acetone
Acrylonitrile
Methanol
Propylene oxide

Table 2.—Initial List of Taxable Imported Chemical Derivatives—Continued

Taxable substance
Polypropylene resins
Ethylene oxide
Ethylene dichloride
Cyclohexane
Isophthalic acid
Maleic anhydride
Phthalic anhydride
Ethyl methyl ketone
Chloroform
Carbon tetrachloride
Chromic acid
Hydrogen peroxide
Polystyrene homopolymer resins
Melamine
Acrylic and methacrylic acid resins
Vinyl resins
Vinyl resins, nspf

The Secretary of the Treasury may delist chemical derivatives (including statutorily listed derivatives) as necessary to carry out the purpose of the tax (except that acrylonitrile may not be delisted). In addition, the Secretary is to add chemical derivatives to the list if taxable feedstock chemicals (under Code sec. 4661) comprise over 50 percent of the molecular weight of the raw materials used to produce the chemical derivative. The Secretary may also add a chemical derivative to the list if taxable feedstock chemicals comprise over 50 percent of the value of the raw materials used to produce the chemical derivative.

The tax on imported chemical derivatives terminates at the same time and under the same conditions as the petroleum tax and the tax on feedstock chemicals.

Leaking underground storage tank taxes

The costs incurred in the cleanup of petroleum releases and releases of natural or synthetic gases are not covered by the Superfund. Present law (Code secs. 4041, 4042, and 4081) imposes excise taxes of 0.1 cent per gallon on (1) gasoline, diesel fuel, and special motor fuels sold by a producer or importer; (2) liquid fuels (other than kerosene, gas oil, liquified petroleum gas, or fuel oil) used in motor vehicles, motor boats, or trains, or used for aviation; and (3) fuels used in commercial transportation on inland waterways.[7] Receipts from these taxes are deposited into a separate trust fund known as the Leaking Underground Storage Tank Trust Fund to

[7] A technical correction to clarify this intent is included in section 202(a) of H.R. 2636 ("Technical Corrections Act of 1987").

pay cleanup and related costs associated with leaking underground storage tanks containing petroleum products.

The leaking underground storage tank taxes are scheduled to expire on December 31, 1991. The taxes will terminate earlier if the cumulative tax receipts exceed $500 million.

B. Prior Excise Tax on Hazardous Waste

Post-closure liability tax

Prior to its retroactive repeal by the Superfund Revenue Act of 1986 (100 Stat. 1760), an excise tax of $2.13 per dry-weight ton of hazardous waste was imposed on the receipt of hazardous waste by the owner or operator of qualified hazardous waste disposal facilities. Receipts from this tax were deposited into a separate trust fund known as the Post-Closure Liability Trust Fund to pay liabilities arising out of certain closed hazardous waste disposal sites.

For purposes of the post-closure liability tax, the term hazardous waste was defined as any waste (1) having the characteristics identified under section 3001 of the Solid Waste Disposal Act, as in effect on December 11, 1980 (other than waste the regulation of which had been suspended by Congress on that date), and (2) that is subject to reporting and recordkeeping requirements under the Solid Waste Disposal Act as in effect on that date. In addition, the tax applied only to hazardous waste that would remain at the facility after the facility was closed. A qualified hazardous waste disposal facility was defined as any facility that had received a permit or had been accorded interim status under the Solid Waste Disposal Act.

Taxpayers who paid the post-closure liability tax prior to its repeal are entitled to a refund of the tax, plus interest.

IV. DESCRIPTION OF H.R. 2497 (AND H.R. 2498)

A. Tax and Trust Fund Provisions

(H.R. 2497 and Title I of H.R. 2498)

Imposition of tax

The bills [8] would impose an excise tax on the amount of sulfur dioxide and nitrogen oxides that are discharged into the atmosphere by certain boilers and furnaces. The tax would be imposed on the person owning or operating the boiler or furnace that emitted the sulfur dioxide or nitrogen oxides into the atmosphere.

Under the bills, a boiler or furnace would be subject to tax (a "taxable boiler or furnace") if (1) the boiler or furnace is used in the process of burning natural gas, petroleum, coal (including lignite), or any other fuel derived from natural gas, petroleum, or coal for the purpose of producing steam, and (2) the boiler or furnace is located in the United States. For this purpose, the United States includes the 50 States, the District of Columbia, Puerto Rico, the Northern Mariana Islands, the Trust Territory of the Pacific Islands, and any other territory or possession of the United States.

An exception to the tax would be provided for any taxable boiler or furnace that has a heat input rate of not more than 100 million Btu's per hour.[9] In addition, an exception to the tax would be provided for any taxable boiler or furnace that has a heat input rate of more than 100 million Btu's per hour but not more than 250 million Btu's per hour, but only for the period that the average hourly rate of sulfur dioxide and nitrogen oxides emitted into the atmosphere each does not exceed 1.2 pounds per million Btu's.

Amount of tax

The amount of tax imposed on the emission of sulfur dioxide and nitrogen oxides by a taxable boiler or furnace would depend on the type of emission, the amount of emission, and the rate of emission for each 1 million Btu's of energy produced by the boiler or furnace. (See Table 3.)

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[8] H.R. 2497 and Title I of H.R. 2498 contain identical tax provisions and essentially the same trust fund provisions. The Committee on Ways and Means hearing is specifically on H.R. 2497.

[9] A Btu, or British thermal unit, is a measure of energy content. One Btu is the amount of energy needed to raise the temperature of one pound of water by one degree Fahrenheit. One million Btu's are contained in 975 cubic feet of natural gas, 7.2 gallons of crude oil, 80 pounds of coal, or 293 kilowatt-hours of electricity.

Table 3.—Proposed Tax Rates for Sulfur Dioxide and Nitrogen Oxide Emissions

	The tax rate per pound is:
Sulfur Dioxide Emissions	
If the pounds of sulfur dioxide emitted per million Btu's of energy are:	
Less than 0.6	0 cents
At least 0.6 but less than 1.2	15 cents
At least 1.2 but less than 2.0	30 cents
At least 2.0	45 cents
Nitrogen Oxides Emissions	
If the pounds of nitrogen oxides emitted per million Btu's of energy are:	
Less than 0.4	0 cents
At least 0.4 but less than 0.7	10 cents
At least 0.7 but less than 1.4	25 cents
At least 1.4	45 cents

In determining the emissions rate for any taxable boiler or furnace, the pounds of sulfur dioxide or nitrogen oxides emitted per million Btu's of energy would be determined on an hourly basis.

The rates of tax under the bills would be phased in over three calendar years by imposing (1) for 1989, a tax equal to 25 percent of the tax that would otherwise be imposed; (2) for 1990, a tax equal to 50 percent of the tax that would otherwise be imposed; and (3) for 1991 and thereafter, the full tax.

For any calendar year beginning after 1990, the rates of tax imposed on the emission of sulfur dioxide and nitrogen oxides would be adjusted for inflation. The amount of the inflation adjustment for any calendar year would be determined by comparing the Consumer Price Index for the immediately preceding calendar year with the Consumer Price Index for the 1989 calendar year.

Continuous emissions monitoring devices

Under the bills, the amount of sulfur dioxide and nitrogen oxides emitted from a taxable boiler or furnace generally would be determined by the use of continuous emissions monitoring devices.

A device would qualify as a continuous emissions monitoring device only if (1) the device is designed to measure the amount of sulfur dioxide and nitrogen oxides emitted into the atmosphere from a taxable boiler or furnace per million Btu's of energy produced by the boiler or furnace, and (2) the device meets any performance and quality standards that are required under regulations prescribed by the Treasury. Two or more boilers or furnaces that are monitored by a single continuous emissions monitoring device would be treated as a single boiler or furnace.

The owner or operator of a taxable boiler or furnace with a heat input rate of not more than 250 million Btu's per hour could elect to determine the average hourly rate of sulfur dioxide and nitrogen oxides emitted into the atmosphere from such boiler or furnace for any period (solely for purposes of the small boiler or furnace exception described above) on the basis of an analysis (determined under regulations prescribed by the Treasury) of the fuel used in the boiler or furnace during the period.

Special rules would apply to any taxable boiler or furnace that is not monitored during any period by a continuous emissions monitoring device. First, during such period, the boiler or furnace generally would be treated as emitting into the atmosphere a number of pounds of sulfur dioxide and nitrogen oxides as determined by the Treasury on the basis of an analysis of the fuel used in such boiler or furnace during the period. Second, the rate of tax imposed on emissions during such period would be 50 cents per pound. These rules would not apply to a boiler or furnace that has a heat input rate of not more than 100 million Btu's per hour or to a boiler or furnace with respect to which the owner or operator elects the fuel analysis method of determining qualification for the small boiler or furnace exception.

If a continuous emissions monitoring device becomes inoperative through no fault of the owner or operator of the boiler or furnace and the device had been continuously operating for the 90-day period immediately preceding the date the device became inoperative, then, for the first 30 days after the date the device became inoperative, the boiler or furnace would be treated as emitting into the atmosphere a number of pounds of sulfur dioxide and nitrogen oxides equal to 125 percent of the average number of pounds of sulfur dioxide and nitrogen oxides per million Btu's that were emitted during the 90-day period preceding the date the device became inoperative. For purposes of this rule, a device would be considered inoperative if it does not measure the amount of sulfur dioxide or nitrogen oxides emitted per million Btu's of energy produced or if it does not satisfy the performance or quality standards prescribed in Treasury regulations.

Credit for cost of pollution control equipment

The bills would provide a credit against the excise tax for any calendar quarter in an amount equal to 25 percent of the amount of deemed depreciation for such quarter on pollution control equipment of the taxpayer. In order for property to qualify as pollution control equipment for purposes of the credit, the property must be subject to the allowance for depreciation for income tax purposes and must be used to abate sulfur dioxide, nitrogen oxides, or other pollutants emitted by a taxable boiler or furnace. Additionally, the property must be part of a certified pollution control facility as defined in Code section 169(d). (Code sec. 169 allows the cost of certain pollution control facilities to be recovered through 60-month amortization, rather than the regular allowance for depreciation.)

The deemed depreciation for any calendar quarter would be an amount equal to 25 percent of the annual depreciation that would be allowable if the cost of the pollution control equipment (without reduction for salvage value) was depreciated ratably over a 10-year

period beginning with the first day of the calendar quarter during which the property was placed in service. In the case of pollution control equipment placed in service before January 1, 1988, any deemed depreciation before such date would not be taken into account in determining the credit.

Deductibility against income tax

The excise tax imposed by the bills would be fully deductible against Federal income taxes.

Effective date

The excise tax would take effect on January 1, 1989.

Establishment of SANE Trust Fund

The bills would establish in the Treasury a trust fund designated as the Sulfur and Nitrogen Emissions Trust Fund ("SANE Trust Fund"). An amount equivalent to the receipts from the excise tax on sulfur dioxide and nitrogen oxide emissions would be appropriated to the SANE Trust Fund.

Under H.R. 2497, amounts in the SANE Trust Fund would be available, as provided in appropriation Acts, to assist taxpayers subject to the excise tax in reducing the emission of sulfur dioxide and nitrogen oxides into the atmosphere and to pay all the expenses incurred by the Treasury Department in administering the excise tax. Under H.R. 2498, amounts in the SANE Trust Fund would be available, as provided in appropriation Acts, to carry out Title II of H.R. 2498 and to pay all the expenses incurred by the Treasury Department in administering the excise tax and by the EPA in administering Title II of H.R. 2498.

Under both bills, the SANE Trust Fund would be authorized to borrow from the general fund of the Treasury amounts that are necessary to carry out the purposes of the Trust Fund. The maximum amount of repayable advances outstanding at any time would be limited to $2 billion. Advances would be repaid with interest to the general fund of the Treasury when the Secretary of the Treasury determines that money is available within the SANE Trust Fund to make repayments. All advances would be required to be repaid on or before December 31, 1990.

The SANE Trust Fund would be managed by the Secretary of the Treasury, who would be required to report annually to Congress on the financial condition and operation of the Fund.

B. Acid Deposition Control Assistance Program

(Title II of H.R. 2498)

Loan provisions

Title II of H.R. 2498 would authorize the Administrator of the EPA (under regulations prescribed by the EPA) to make loans from the SANE Trust Fund to a qualified person for the purpose of either (1) constructing a new electric power generating unit to replace an existing fossil-fuel fired steam generating unit, or (2) purchasing and installing pollution abatement equipment at any fossil-fuel fired steam generating unit to reduce emissions of sulfur diox-

ide or nitrogen oxides. A qualified person is any owner or operator of a taxable boiler or furnace that has a heat input rate of more than 100 million Btu's per hour.

A qualified person would be required to apply to the Administrator of the EPA for a loan from the SANE Trust Fund, and the selection of loan recipients would be determined pursuant to criteria established in regulations published by the EPA.

Under the bill, the criteria for selecting loan recipients must include consideration of each of the following:

(1) the amount by which the emission rate would be reduced after completion of the project for which the loan may be granted;

(2) the cost effectiveness of the project;

(3) the potential impact of the project on the applicant's ratepayers;

(4) the potential impact of the project on the coal market equilibrium existing on the date of enactment of the bill; and

(5) any comments received from the Governor of the State in which the applicant resides as to the project and any Statewide concerns.

The principal amount of any loan for the construction of a new electric generating unit (a "construction loan") would be limited to 20 percent of the capital expenditures incurred in constructing the new unit. In order to qualify for a construction loan, the new unit must replace at least 75 percent of the capacity of the unit being retired and the unit being retired must have had an annual average emissions rate in excess of 2.0 pounds of sulfur dioxide per million Btu's of energy and 1.0 pound of nitrogen oxide per million Btu's of energy. Construction loans would only be available during the first 15 years following the date of enactment of the bill.

The principal amount of any loan for the purchase and installation of pollution abatement equipment (an "equipment loan") would be limited to the amount of capital expenditures incurred in purchasing and installing the equipment. Equipment loans would be available only during the first 10 years following the date of publication of final regulations by the EPA under Title II of the bill. Any person who receives an equipment loan would not be eligible for the credit under the bill against the excise tax for any portion of the cost of the equipment.

The interest rate for a construction loan would be two percentage points below the existing prime rate of interest, as determined by the Administrator of the EPA. An equipment loan would not bear interest.

The Administrator of the EPA would be authorized to forgive a portion of any construction or equipment loan made from the SANE Trust Fund to a qualified person. In the case of a construction loan, the Administrator of the EPA would be authorized to forgive one-fifteenth of the loan for each full calendar year that remains in the 15-year loan eligibility period as of the date the new electric generating unit commences operations. In the case of an equipment loan, the Administrator of the EPA would be authorized to forgive one-tenth of the loan for each full calendar year that remains in the 10-year loan eligibility period as of the date the qualified person installs and begins operation of the pollution abatement equipment.

The portion of the principal amount of any construction loan that has not been forgiven by the Administrator of the EPA would be required to be repaid ratably (one-fifteenth per year) over a 15-year period, while the portion of the principal amount of any equipment loan that has not been forgiven would be required to be repaid ratably (one-tenth per year) over a 10-year period. The repayment of construction loans and equipment loans would commence in the first full calendar year that follows the year that the construction or installation is completed.

Any utility that accepts a construction or equipment loan from the SANE Trust Fund would be prohibited from including in its rate base (or otherwise recovering from ratepayers) the percentage of the cost of any property that is purchased by the utility and that is covered by the loan.

Studies

Title II of H.R. 2498 would require the Administrator of the EPA and the Secretary of the Treasury to study the effectiveness of the excise tax in reducing the amount of sulfur dioxide and nitrogen oxide emissions and to recommend to Congress appropriate adjustments to the level of the tax or to other provisions of the bill.

In addition, the Administrator of the EPA would be required to study the results achieved by the excise tax in controlling pollution and to address the potential application of the pollution tax approach in alleviating other immediate or potential environmental problems, such as the dangers posed by hydrocarbons and airborne toxics. Reports containing the results of each study would be required to be submitted to Congress five years after the date of enactment of the bill.

Disposition of excess funds held by the SANE Trust Fund

Under Title II of H.R. 2498, if at the end of any fiscal year the amount of funds remaining in the SANE Trust Fund exceeds the total amount of construction and equipment loans made during such fiscal year, the excess would be authorized to be appropriated for any of the following:

(1) any clean coal technology research or demonstration project;

(2) any energy conservation program;

(3) any research program relating to the environmental effects of sulfur and nitrogen emissions;

(4) any program for the purpose of mitigating environmental damages related to sulfur and nitrogen emissions;

(5) any other programs authorized by the Congress which are related to the problems associated with sulfur and nitrogen emissions;

(6) any alternative energy research and development program;

(7) any job retraining program for workers displaced as a result of the bill; and

(8) any expenses incurred by the Department of the Treasury and the EPA in administering the bill.

The amounts that would be authorized to be appropriated under the bill for the administrative expenses of the Treasury and the EPA would be limited to two percent of the projected revenues for the subsequent fiscal year, with one percent allocated to the Treas-

ury and one percent allocated to the EPA. If the Administrator of the EPA does not submit the reports required by the bill on a timely basis, no amount would be authorized to be appropriated to the EPA until the reports are submitted.

V. ISSUES RELATING TO THE TAXATION OF EMISSIONS

A. Market vs. Regulatory Approaches to Reducing Emissions

Emissions tax

If the sulfur dioxide and nitrogen oxides created by the burning of fossil fuels damage lakes and streams, kill fish, and reduce timber and crop yields, resource costs are imposed on society. The total cost to society—the firm's internal costs for labor, fuel, etc., plus the environmental cost—may exceed the value society places on the firm's product because no one pays the environmental costs.

The theory of an emissions tax is to charge the polluter for the environmental costs of its emissions—the "polluter pays" principle. This provides a financial incentive for firms to reduce emissions by using any technology that saves more in emissions taxes than it costs. An emissions tax also creates opportunities for technological innovation. In addition, to the extent that the price of the firm's products reflects the emissions tax, some consumers will reduce their demand for the firm's products—which also will reduce emissions. If the rate of the emissions tax equals the value of the environmental damage caused by extra units of emissions, then this outcome is efficient because consumers will then purchase the firm's product only if the value of the product exceeds all production costs, including the environmental costs created by the emissions.

Other market-oriented methods of pollution control

An emissions tax is a market approach to pollution control. Firms determine the least costly method of production taking account of the tax on pollution. Another market approach to pollution control is the EPA's "bubble program." Under the bubble program, a firm may increase its emissions at one facility only if it reduces emissions by a like amount at another facility within the same geographic region, or "bubble." The cost of polluting in this case does not involve a tax, but having to reduce pollution elsewhere.

The EPA also is studying a marketable emissions permit system. The idea is similar to the bubble. Increased emissions would be permitted within a geographic region only if reductions of equal or greater magnitude are achieved at some other site within the region. This would be accomplished by issuing permits that specified the amount of emissions that the permit holder would be allowed. A firm that reduced its overall level of emissions would be allowed to sell its permit to another firm which wanted to expand its emissions. The marketable permit system allows trades of emissions between companies, while the bubble concept is limited to facilities owned by a single company. The initial allocation of permits

can be made by auction or according to the emissions levels which firms are allowed under present law.

Direct regulation

Direct regulation is the predominant approach to pollution control in the United States. Direct regulation usually involves specifying permissible quantities of emissions, such as the New Source Performance Standards provided under the Clean Air Act, or specifying a particular remedy, such as mandating scrubbers.

Direct regulation of emissions levels has the advantage of targeting the amount of reduction. Emissions limitations also may facilitate monitoring compliance. By contrast, establishing an emissions tax would lead to reductions, but it may be difficult to determine the tax rate necessary to yield the desired quantity reduction. However, it also is difficult to determine the appropriate quantity reduction which is consistent both with reducing environmental harm and with efficient resource use. Specifying technology standards may achieve short-run goals rapidly, but is unlikely to be cost effective. The market-oriented emissions reduction policies allow firms greater flexibility in choosing low-cost emissions control technologies.

B. Incentive Effects of Emissions Taxes

Raising the price of most goods induces consumers and producers to economize. An emissions tax such as contained in H.R. 2497 would allow market forces to reduce sulfur dioxide and nitrogen oxide emissions. In some cases, the response might involve substituting low-sulfur coal for high-sulfur coal. In other cases, this might mean installing scrubbers. The tax also could create incentives to shift production to more environmentally clean facilities. And, depending upon the costs of retrofitting, the tax could induce the early retirement of old boilers. Under an emissions tax, the producer would tailor its response to its circumstances. Since the profit motive drives the producer, reductions in emissions would be achieved at the least cost to producers.

Since many pollution abatement programs require substantial investment, certainty of the tax may be critical for its effectiveness. A temporary tax would be unlikely to induce substantial investment in pollution control equipment. Conversely, a tax that is scheduled to increase over time would stimulate greater pollution control investment in the short term than a flat-rate emissions tax.

H.R. 2497 has a rate schedule graduated by emissions per million Btu's. Consequently, the greatest incentive effects fall on those with the highest emissions rate per Btu. Those with low emissions rates may have little or no incentive to reduce their emissions.

While the effect of tax incentives is clear, tax incentives will not necessarily produce immediate reductions in emissions. For example, current technology can achieve reductions in nitrogen oxides by two means: (1) altering the burner configuration and burn characteristics; or (2) installing a selective catalytic reduction device ("SCR") which removes nitrogen oxides from the flu gases (in much the same way scrubbers remove sulfur dioxide). For some boiler configurations it is relatively easy to alter burn characteristics, but

for others this only can be achieved by rebuilding the boiler. The company's choice may be to build a new boiler or install a SCR, both of which involve high capital costs, or to operate the old boiler and pay the tax. Thus, it may be in the company's interest to pay an emissions tax for many years until retirement of the boiler. The incentive only would change production technology in the long run. To the extent that the tax is passed forward to the consumer, however, reduced demand would lower emissions levels in the short run.

The Congressional Budget Office ("CBO") estimates that electric utilities released 15.8 million tons of sulfur dioxide and 6.6 million tons of nitrogen oxides in 1985. The CBO estimates that 97 percent of the sulfur dioxide emissions came from older plants built before the NSPS of 1971, and that in absence of further abatement efforts by 1995, these older plants still will account for 90 percent of sulfur dioxide emissions by utilities.[10] Unless the tax on emissions is sufficiently high to induce significant fuel switching, or retrofitting, or to accelerate the retirement of old boilers, it is likely that a substantial amount of taxable emissions would remain for many years.

Electric utilities produce 65 percent of man-made sulfur dioxide in the United States.[11] Consequently, their behavior would be most affected by the proposed emissions tax. State regulatory authorities generally determine the rates charged by electric utilities. The regulatory process might mitigate some of the advantages of an emissions tax described above.

While the regulatory process differs by State, typically regulators permit the utilities to pass through direct cost increases, subject to periodic reviews to ascertain that the utility is operating in a cost minimizing way. With full cost pass-through, emissions reductions might be slower than in an unregulated market. However, if regulators are slow to approve the pass-through of costs, or require that any such change be phased in to soften the blow on the consumer, utility companies may respond much as would unregulated firms.

The regulatory process also may bias an electric utility in the direction of one method of emissions control over another. Many economists believe that the rate-making regulatory process biases the regulated company in the direction of capital intensive-production methods. The empirical evidence on this point is not conclusive. If this does occur, it diminishes the gains from flexibility that a market approach would provide.

C. Appropriate Rate of Tax

The appropriate rate of tax on emissions depends upon the goal of the tax. The tax could be used primarily to raise revenue or, alternatively, to reduce pollution. The revenue-maximizing tax rate could be either greater or smaller than the tax rate which would accurately reflect environmental harms.

H.R. 2497 proposes a tax rate schedule graduated by emissions rate. To avoid completely the tax on sulfur dioxide, emissions rates must be as low or lower than those imposed by the 1979 NSPS for

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[10] U.S. Congress, Congressional Budget Office, "Curbing Acid Rain: Cost, Budget, and Coal-Market Effects," June 1986, p. 10 (hereinafter referred to as CBO, "Curbing Acid Rain").

[11] CBO, "Curbing Acid Rain," p. 1.

new coal-fired electric utility boilers. To avoid completely the tax on nitrogen oxides, emission rates must be lower than those necessary to meet the 1979 NSPS. It is likely that those coal-fired boilers which have come into service satisfying the 1971 NSPS would face the 15-cent tax rate on sulfur dioxide and the 10-cent tax rate on nitrogen oxides. Oil and gas boilers installed under NSPS might face no tax liability because the sulfur dioxide and nitrogen oxides NSPS were stricter for these fuels. Older boilers presumably would face the higher tax rates. As of 1985, 639 utility and industrial boilers with capacity of 250 million Btu's have been put in service under the NSPS; of that total, 250 are coal-fired.

Full efficiency would call for taxing each source according to the harm it creates. The same amount of acid deposition in two different areas of the country does not create the same environmental harm. Some areas of the country possess soils that are better able to neutralize acid. For example, New England is considered to be at greater risk than Ohio even though measured precipitation is more acidic in Ohio than New England. In addition, two-thirds of all sulfur compounds deposited have their source within 300 miles.[12] This suggests that the external resource costs which arise from a power plant in Albany, New York, the emissions from which land in New England, are greater than those which arise from a power plant in Memphis, Tennessee, the emissions from which land in Ohio. Accordingly, uniform taxation could induce too much emissions reduction at too high a cost in Tennessee and too little reduction in New York. In theory, the tax rate also should vary with the atmospheric conditions which determine where the emissions from each source land. Thus, full efficiency would require differential taxation.

The information costs necessary to achieve full efficiency are substantial. Full efficiency would require knowing from which individual sources acid deposits originate. At present, scientific knowledge does not permit such an identification of sources. If the source is identified, the specific environmental cost should be assigned to the source. Again, scientific knowledge does not permit such an assignment. Uniform tax rates economize on information costs.

Under H.R. 2497, if the Memphis plant's emissions were 2.1 pounds of sulfur dioxide per hour while those of the Albany plant were 1.8 pounds per hour, the Memphis plant would be taxed at a rate of 45 cents per pound while the Albany plant would be taxed at 30 cents per pound, even though the Albany plant may create the greater environmental harm. Similarly, two plants in the same area might be taxed at different rates even though their emissions are equally harmful on a per pound basis. It might, in fact, be cheaper to reduce emissions at the plant with the lower emissions rate, perhaps because it is a newer facility. Thus, the graduated tax rates under the bill might induce initial reduction efforts at the plant where reductions are most costly to achieve, even though the environmental benefit is independent of which of the plants makes the reduction.

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[12] OTA, "Acid Rain," p. 12.

An additional concern in developing an emissions tax is determining which emissions should be taxed. Theoretically, each type of emission should be taxed according to the incremental harm it creates. The Congress identified particulate matter as a harmful emission from electric utility plants when it established its 1971 and 1979 NSPS. Others identify hydrocarbons and carbon monoxide as harmful emissions. By not taxing these emissions while taxing sulfur dioxide and nitrogen oxides, abatement efforts may result in an increase in particulate matter, carbon monoxide, and other emissions. Further, under the theoretical principles of an emissions tax, all emissions should be taxed, not solely those emissions which arise from boilers. H.R. 2497 exempts non-boiler sources from taxation as well as small boilers.

D. Regional Effects

It is difficult to determine the distribution of benefits from reducing acid deposition since the costs to the environment and property are not known. To the extent that the northeast receives more acid deposition than the midwest or west, the northeast would receive a greater share of the benefits from reduction of emissions. The fact that the soils of the northeast are more susceptible to damage from acid magnifies the gain to that region. A substantial amount of the benefits created would accrue to Canada.

Different regions of the country emit sulfur dioxide and nitrogen oxides in different amounts and different rates. Table 4 below shows emission rates and the maximum hypothetical tax liability under H.R. 2497 by region of the country and type of boiler. The table applies only to the sulfur dioxide portion of the tax. The table does not present a revenue estimate because it assumes no fuel switching, scrubber installation, reduction in electricity demand in response to the tax, or offset against the corporate income tax.

Table 4.—Sulfur Dioxide Emissions and Maximum Hypothetical Tax Liability Under H.R. 2497 by Region, 1980 Levels at 1991 Tax Rates [1]

Region	Sulfur dioxide emissions (1,000 tons/yr)		Sulfur dioxide emission rates (lb/million Btu's)		Hypothetical tax liability ($ billions)		
	Utility	Other industry	Utility	Other industry	Utility	Other industry	Total
New England	405	122	1.8	1.9	$0.247	$0.092	$0.339
Mid Atlantic	2,059	464	2.2	1.3	1.646	0.251	1.897
East North Central	5,891	848	3.6	2.2	5.133	0.667	5.800
West North Central	1,886	100	3.4	1.2	1.537	0.041	1.578
South Atlantic	3,565	567	2.3	1.6	2.499	0.360	2.859
East South Central	2,656	303	3.3	1.5	2.352	0.182	2.534
West South Central	386	224	0.3	0.5	0.000	0.042	0.042
Mountain	465	87	0.7	0.9	0.132	0.021	0.153
Pacific	144	149	1.0	0.7	0.044	0.020	0.064
U.S.	17,505	2,865	1.9	1.1	$13.590	$1.676	$15.266

[1] This table is not a revenue estimate of H.R. 2497. The table does not account for (1) any fuel switching or scrubber installation induced by the proposal; (2) the decline in sulfur dioxide emissions since 1980; (3) reduced electricity demand which the proposal could induce; and (4) the deductibility of the emissions tax against the corporate income tax. The calculation of hypothetical tax liability is derived from State average emission rates, not from individual plant data. Nitrogen oxides emissions are excluded.

Source: Joint Committee on Taxation. Based on data provided by the Office of Technology Assessment. 1991 tax rates determined assuming zero inflation.

Any program to reduce emissions will increase the cost of producing electricity and other products and ultimately will be borne by the public. An emissions tax is no different, but perhaps has the advantage of directly disclosing to consumers the costs of pollution control. Under the bill, electric rates generally would increase throughout the country. Like an excise tax on electricity, an emissions tax may be viewed as regressive. In analyzing a similar proposal, the Congressional Budget Office estimated that electric rates would average 4.7 percent higher in 1995 than under current law.[13]

Electric rates would not rise uniformly under the bill. Rates in the midwest would rise more than those in the east or west because the east and west have access to low sulfur coal. Midwestern utilities predominantly burn coal from Illinois, Indiana, and Ohio which has a higher sulfur content. Consequently, either paying an emissions tax or reducing sulfur content by switching to low sulfur coal or scrubbers would cost midwestern utilities more. The mix of generation facilities (fossil fuel, hydro, nuclear) also varies by region. The mix of facilities affects the electricity rate increase by region. Also, some States presently impose stiffer environmental standards than others. Consumers in those States which have less strict standards would experience greater rate increases. Table 5 below shows the effect on electricity rates by region.

Table 5.—CBO Estimate of Effect of Sulfur Dioxide Tax on Electricity Rates by Region of the Country, 1995 [1]

[Cents per kilowatt hour]

Region	Present law	Sulfur dioxide tax	Percent change
New England	8.075	8.285	2.6
Mid Atlantic	7.087	7.360	3.9
East North Central	5.628	6.144	9.2
West North Central	5.262	5.646	7.3
South Atlantic	5.533	6.020	8.8
East South Central	4.950	5.293	6.9
West South Central	7.845	7.965	1.5
Mountain	4.955	5.091	2.7
Pacific	5.685	5.685	0.0
U.S.	6.200	6.490	4.7

[1] The CBO study assumes a $600 per ton tax on sulfur dioxide and no tax on nitrogen oxides. A rate of $600 per ton of sulfur dioxide is the middle rate of H.R. 2497. The study estimates the extent of scrubber installation and fuel switching to determine the effect on utility costs and rates.

Source: CBO "Curbing Acid Rain," pp. 86-87.

While the midwest and southeast would experience the greatest electricity rate increases under the bill, currently both regions face below average electric rates. The rate increases that would result

[13] CBO, "Curbing Acid Rain," p. 84.

from this proposal would not necessarily move those rates above the national average. Nevertheless, the relative increase in energy costs would make these regions less attractive to electricity-intensive industries.

E. Effects on the Electric Utility Industry

Electric utilities do not generate all of the country's electricity. The role of secondary suppliers of electricity recently has expanded. Secondary supply comes from cogeneration facilities, private hydro facilities, and other sources. While large cogeneration facilities would be liable for the tax, small facilities would not be liable. Secondary suppliers sell their electricity to the electric utilities. Increasing the production costs of electric utilities through the imposition of an emissions tax would lead to an expansion of the supply offered by non-fossil fuel and small scale (less than 100 million Btu's per hour, the zero-tax emissions level under the bill) fossil fuel secondary suppliers.

H.R. 2497 also would create incentives to import power produced in Canada. Recently, the northeast has increased purchases of Canadian power. Power importation would cost domestic companies profits and employment.

Scale economies and cost consideration have made the 500-megawatt fossil fueled power plant the choice for new capacity. The proposed emissions tax could make it relatively more efficacious to add new capacity with non-fossil fuel facilities or with very small scale fossil fueled facilities which are below the zero-tax emissions level under the bill. Power importation, growth in secondary supply, and new non-fossil fuel capacity would mitigate the rate increase faced by consumers.

F. Effects on the Coal Industry

The proposed tax under H.R. 2497 would place midwestern coal at a market disadvantage because of its high sulfur content. Substantial substitution of low sulfur coal from the west or from West Virginia might result. This could create additional mining jobs in those two areas, while the midwest could experience a loss of production and jobs.

Table 6.—CBO Estimate of Coal Mining Employment by Region, 1995[1]

Region	No tax (miner years)	Tax (miner years)	Percent change
New England	0	0	—
Mid Atlantic	29,299	22,749	−22.4
E. N. Central	27,211	15,871	−41.7
W. N. Central	4,420	2,890	−34.6
S. Atlantic	109,567	129,483	+18.2
E. S. Central	73,148	72,857	−0.4
W. S. Central	9,234	9,031	−2.2
Mountain	22,308	23,530	+5.5
Pacific	48	48	0.0
U.S.	275,172	276,461	+0.4

[1] CBO's analysis assumes a $600 per ton tax on sulfur dioxide and no tax on nitrogen oxides. The study estimates fuel switching and scrubber installation to determine mining employment effects.

Source: Adapted from CBO, "Curbing Acid Rain," p. 92.

Overall mining employment could increase if the mining of low sulfur coal from West Virginia is more labor intensive than the mining of midwestern coal. The Congressional Budget Office estimates that this is the case.[14] Hence, as utilities switch from midwestern coal to coal from West Virginia, overall mining employment would rise.

If an emissions tax makes the installation of scrubbers more cost effective than the purchase of low sulfur coal, the shift of mining employment from the midwest would be attenuated. In addition, government subsidies for scrubber installation, as provided in Title II of H.R. 2498, would reduce the rate increases faced by consumers. A scrubber subsidy program would dampen rate increases in the midwest more than elsewhere because it would permit the continued use of low cost local coal. The increase in scrubber demand should increase employment in that industry.

G. Effects on Other Industries

Electricity provides 16.6 percent of the energy consumed by U.S. industry. Electricity consumption varies by industry.[15] Table 7 below identifies the primary metals; chemical; stone, clay, and glass; paper; and rubber industries as the most electricity intensive.

[14] *Ibid.*

[15] U.S. Department of Energy, Energy Information Administration, "Manufacturing Sector Energy Consumption, 1985: Provisional Estimates," *Monthly Energy Review*, January 1987.

Table 7.—Electricity Costs as a Percentage of Value of Shipments by Manufacturing Sector, 1985 [1]

[Dollar amounts in billions]

Industry group	Electricity expense	Value of shipments	Electricity expense as a percent of the value of shipments
Food and kindred products	$2.51	$296.1	0.8
Tobacco products	0.07	20.6	0.3
Textile mill products	1.33	52.6	2.5
Paper and allied products	2.78	97.6	2.8
Chemical and allied products	6.73	214.3	3.1
Petroleum and coal products	1.82	194.0	0.9
Rubber and misc. plastics	1.37	48.2	2.8
Stone, clay, and glass	1.76	57.3	3.1
Primary metal industries	6.94	125.8	5.5
Fabricated metal products	1.38	169.0	0.8
Machinery except electrical	1.73	212.6	0.8
Electric and electronic	1.66	185.5	0.9
Transportation equipment	1.74	313.4	0.6
Instruments and related	0.44	56.7	0.8
Total	32.26	2,043.7	1.6

[1] Calculations do not account for regional differences in electric rates.

Source: Department of Energy, *Monthly Energy Review* (January 1987).

A five-percent increase in the cost of electricity could lead to a 0.2 percent increase in the costs of the primary metals industry and a 0.15 percent increase in the costs of the chemicals industry.

Table 7 may understate the effect of an emissions tax on these industries since emissions from non-utility boilers are omitted. As measured in Btu's, the chemicals industry uses almost three times as much natural gas and fuel oil as electricity. To the extent that these fuels are used to fire boilers, their use might be subject to the tax. Similarly, the petroleum industry uses seven times as much natural gas and oil as electricity; the stone clay and glass industry uses four times as much natural gas and fuel oil as electricity; and the primary metals industry uses one and a half times as much natural gas and fuel oil as electricity.

These industries would confront higher costs under an emissions tax which could make them less competitive in domestic and for-

eign markets. Also, regional differences in electric rate increases eventually could produce some industry relocation.

H. Administrative Concerns

Under current law, the EPA and State agencies monitor the emissions of utility plants, usually once per year or more frequently. In addition, State regulatory authorities require detailed production data from the utilities. The bill would require continuous monitoring, which is more stringent than present law. For each hour of operation the utility would have to monitor the amount of sulfur dioxide and nitrogen oxides in the stack and the boiler temperature. Stack monitoring technology currently exists, although some questions about reliability have been raised.[16]

Utilities already monitor boiler temperatures for State rate regulation purposes. The installation of continuous stack monitors is estimated to cost $50,000 per stack. Estimates of operation and maintenance expense vary from $50,000 to $400,000 per year. An EPA study suggested an accuracy of plus or minus ten percent on sulfur dioxide monitoring and an operating availability rate in excess of 95 percent.[17] At high emission rates and a tax of 45 cents per pound of sulfur dioxide, a 10-percent error could be expensive.

H.R. 2497 would provide a 25-percent penalty on operating a furnace or boiler with an inoperative monitor. The reliability of continuous stack monitors is in dispute. In reviewing a different EPA pilot project, Kilkelly Environmental Associates, Inc. concluded that the sulfur dioxide monitor was available to provide the minimum necessary data only 45 to 60 percent of the time and the nitrogen oxides monitor was available only 27 percent of the time.[18] This could induce operators to install redundant systems, increasing the costs of monitoring.

An alternative to continuous stack monitoring is fuel sampling. Analysis of coal or oil can determine its sulfur content and potential for sulfur dioxide emission. Companies routinely sample the coal they buy to determine the coal's price. The EPA has established standards for fuel sampling and uses fuel sampling in its own emissions monitoring. Similarly, information on the boiler type and burn characteristics can be used to determine nitrogen oxides emissions. Fuel sampling may be a lower cost monitoring option than continuous stack monitoring. H.R. 2497 allows boilers with capacity of less than 250 million Btu's to elect fuel sampling as their monitoring method, but only for determining whether emissions are not subject to tax under the bill.

There are approximately 1,000 fossil-fueled utility facilities. Typically, these facilities contain multiple boilers and more than one stack. While it might be easy to identify and monitor utility boilers, there are a substantial number of industrial boilers. (See Table 8.)

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[16] U.S. Environmental Protection Agency, Office of Air Quality Planning and Standards, "Summary Report: A Pilot Project to Demonstrate the Feasibility of a State Continuous Emission Monitoring System (CEMS) Regulatory Program," June 1986.

[17] *Ibid.*

[18] Kilkelly Environmental Associates, Inc., for The Utility Air Regulatory Group Continuous Monitoring Committee, "An Examination of the Results of the EPA Conesville CEM Demonstration Program," Report No. I159-84-06F, September 1984.

Table 8.—Industrial Boilers by Capacity and Fuel, 1979

Capacity in million Btu's	Coal	Oil	Gas	Total
1,500+	16	9	40	65
500 to 1,499	81	69	103	253
250 to 499	343	336	339	1,018
100 to 249	2,169	511	1,586	4,266
Total	2,609	925	2,068	5,602

Source: U.S. Environmental Protection Agency, "Population and Characteristics of Industrial/Commercial Boilers in U.S.," August 1979, Tables II-15 and II-16.

The total number of utility and industrial boilers is close to 7,000. Monitoring 7,000 sites could pose a significant burden for the Internal Revenue Service.

Natural gas-fired boilers constitute 16 percent of fossil-fueled electric utility capacity and 37 percent of industrial boilers (36 percent of those with capacity greater than 250 million Btu's). These boilers are unlikely to be liable for the tax on sulfur dioxide and are often low nitrogen oxides emitters as well. Continuous stack monitoring of these may be an unnecessary expense.

The Internal Revenue Service would have to write regulations, prepare forms, and provide certification procedures for monitoring equipment to implement H.R. 2497. Since this is an entirely new field of taxation, a certain amount of lead time may be necessary before the effective date. The bill provides for implementation at reduced rates in 1989 and 1990.

At present, two State or local agencies impose emissions taxes. Many State and local agencies charge for emissions permits. States and local governments may view a Federal emissions tax as an intrusion on their tax base. H.R. 2497 does not include provisions for offsetting State and local emissions charges.

I. Experience with Emissions Taxes

California

The United States has limited experience with emissions taxes. In Southern California, the South Coast Air Quality Management District has levied emissions fees since 1978 on sulfur dioxides, nitrogen oxides, carbon monoxide, particulate matter, and organic gases. Any source which annually has total emissions in excess of ten tons is liable for the tax on all emissions. For perspective, a 100 million Btu's boiler using 0.5 percent sulfur coal would have to operate for only 250 hours to produce ten tons of sulfur dioxide.

The South Coast Air Quality Management District contains 22,000 industrial and utility facilities, all of which must obtain annual emissions permits and report levels of emissions. Only 1,600 are liable for emissions fees. Firms report their own emissions levels. They determine emissions levels primarily by fuel sampling and calculations based on burner characteristics. The District audits compliance with on-site monitoring.

Currently, the fee for sulfur dioxide is $167 per ton and for nitrogen oxides $139 per ton. (The lowest rate of tax in H.R. 2497 is $300 per ton for sulfur dioxide and $200 per ton for nitrogen oxides.) The District anticipates revenue from all emissions fees to yield $23 million in fiscal 1988. The District has raised the fees each year. The fees currently are under review with a goal of making them correspond more closely to actual environmental and health harms.

Wisconsin

The State of Wisconsin has assessed an emissions fee since 1976 on emissions above 50 tons per year. Of 1,000 sources identified throughout the State, only approximately 300 are liable for the fee. The purpose of the fee is to cover one-third of the Bureau of Air Management's budget. As in Southern California, firms report their emissions, primarily calculated from fuel sampling and burner characteristics.

The base charge for sulfur dioxide and nitrogen oxides emissions is 20 cents per ton, but depending on the Bureau of Air Management's budgetary needs, surcharges are imposed to meet the one-third budgetary requirement. As a result, the fees are not known to the companies in advance. In 1986, the fee was 29 cents per ton. In 1985, revenue from the fee was $544,000.

West Germany

West Germany has levied an effluents tax at the regional level on discharges into the Ruhr River for more than 20 years. The rate of tax is determined by a chemical analysis of the effluents taken at the source of discharge.[19] In 1984, West Germany instituted a national effluents tax to control water pollution.

Japan

Japan levies a tax on sulfur dioxide emissions. The the tax is assessed at a low rate which varies by location. The tax is nine times greater in areas of high pollution than elsewhere. The tax is assessed annually based on the volume of sulfur dioxides released during the preceding year. Japan also taxes sulfur emissions from automobiles.[20]

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[19] Allen V. Kneese and Blair T. Bower, *Managing Water Quality: Economics, Technology, Institutions,* The Johns Hopkins Press, Resources for the Future, 1968.

[20] Congressional Budget Office, *Environmental Regulation and Economic Efficiency,* March 1985.

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