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ACID RAIN PROVISIONS OF THE 1990 CLEAN AIR AMENDMENTS: AFFECTS ON RESIDENTIAL ELECTRIC CUSTOMERS

by

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(ABSTRACT)

This thesis attempts to explain to what degree residential electricity prices will increase due to compliance with the sulfur dioxide provisions of the 1990 Clean Air Amendments. The Amendments were passed with widely varying estimates of the costs to the final consumer. These estimates ranged from 3 percent to 30 percent.

Models were developed based on the regulatory rate structure of investor-owned utilities in the United States. The utilities were grouped by their historical selection of fuels and pollution control equipment and Chow tests were performed to identify if structural differences exist between these groups. A single equation was then derived that separated variables that created the structural difference. Regressions were then run to test the historical relationship between the electric utilities' costs and residential bills. Next forecasts were run using the regression model above corrected for heteroskedasticity and serial correlation and compared with three estimates of increases in electric bills made before the Bill was passed.

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CHAPTER 1

INTRODUCTION

This thesis explores the affects of the sulfur dioxide (SO_2) acid rain provisions of the 1990 Amendments to the Clean Air Act (the Amendments) on residential electric bills for the continental United States. Cost estimates have been made by various groups, although these studies were conducted before the final Amendments were passed. This thesis attempts to forecast future residential bills based on historical costs and decisions regarding SO_2 control. Aside form the forecast of residential rates this thesis discusses what sulfur dioxide is and ways to control it; why firms pollute the environment even if the pollution is considered harmful; summarizes various provisions of the Amendments and discusses economic theory as it relates to the various provisions of the Amendments; and briefly explains utility rates and structure.

This introductory chapter first explains what acid rain is and why it exists as well as specifically how electric utilities contribute to the acid rain problem. Next Chapter 1 discusses possible current technological solutions and alternatives that electric utilities can employ to reduce emissions of substances that contribute to acid rain. This chapter also discusses the economic reasons why acid rain has become a problem in today's society and why electric utilities and other industrial firms do not voluntarily curb their pollution. Chapter 1 closes with a detailed description of the objective of the thesis as well as the organization of the rest of the study.

1.1 ACID RAIN AND THE EFFECTS OF ACID RAIN

1.1.1 Acid Rain

The atmospheric subcycle of the water cycle purifies the earth's water. Rain and snow as they fall, wash pollutants from the air and in the process of evaporation pollutants are taken up. Therefore as precipitation falls it combines with sulfur and nitrogen oxides (SO_x and NO_x) to produce sulfuric and nitric acids. There is a certain amount of SO_x and NO_x that occurs naturally in the atmosphere that is picked up by precipitation. It is, however, the excessive amount of oxide pollutants from industrial sources that causes acid rain. Sources of acid rain emit SO_2 which combines with oxygen to form sulfur trioxide (SO_3) and sulfur tetroxide (SO_4). Both SO_3 and SO_4 have been linked to respiratory ailments in humans as well as to acid rain.

The greater the concentration of sulfur and nitrogen oxides in the air, the stronger the acids that reach the earth's surface through precipitation. The degree of acidity is measured using the pH scale. The pH scale is a logarithmic measure of acidity and alkalinity present in various substances. Therefore, what may appear to be a small or minor increase in the pH value of precipitation is instead a large increase. By using the pH scale, scientists have been able to record the change in acid content of precipitation as well as the acid level in waterways.

1.1.2 Effects of Acid Rain

When the harmful oxide pollutants fall to earth in the form of acid rain they come in contact with surfaces and materials that can not neutralize them. These materials includes soil, rocks, water, metals and buildings. The acid eats away at surfaces causing them to weather and disintegrate at much quicker rates than they otherwise would have. As acid rain falls into lakes and rivers, it changes their acid levels which disrupts aquatic reproduction and makes the waterways inhabitable for some species of fish and waterlife. The acid component of precipitation also leaches metals from soil and rocks that surround affected bodies of water into the water itself. The leaching of these metals further disrupts aquatic life -- to an even greater degree than is caused by an increase in the acid level of precipitation that falls directly into the waterways.

Winds transport sulfur and nitrogen oxides far from their source. The areas often affected by acid rain do not necessarily have the industries that emit the oxides. Because of the wind transport aspect acid rain is a national and global problem not a localized one. Canada is currently working to reduce its SO_x and NO_x problems since acid rain does not adhere to borders, and the emissions that are produced in one country often drift across borders into other countries, imposing costs on the other nonemitting country's. Europe too is starting to tackle its acid rain problem through the European Economic Community (EEC) because of the acknowledgement of the nonlocalized nature of oxide pollutants. The EEC plan will be put into effect in three phases: 1993; 1998; and 2003. The reduction of oxide pollutants in the European Community applies to all emitting sources of oxide pollutants not just to electric utilities.

1.2 ELECTRIC UTILITIES CONTRIBUTION TO ACID RAIN AND SOLUTIONS THEY CAN EMPLOY TO REDUCE THEIR SO_2 EMISSIONS

1.2.1 How Electric Utilities Contribute to Acid Rain

Electric utilities contribute to the acid rain problem (emitting SO_2) by burning coal. Coal is a plentiful resource in the United States, more so than either oil or gas, other primary fossil fuels burned by electric utilities. Coal is most plentiful in the Appalachia region and in western states. Approximately 54 percent of the coal by weight and 30 percent by heat content is west of the Mississippi River.[1] Western coal, although lower in sulfur is also lower in heat content, an important factor in the selection of a coal for the generation of electricity. Coal mined in the Midwestern states and the Appalachia region has, for the most part, a high-sulfur content and a high heat content. The United States has approximately 27 percent of the world's coal reserves,[2] therefore for economic and national security reasons coal is an extremely important and vital part of the United States' long-term energy plan.

Coal has always been a popular choice of the electric utility industry when choosing a fossil fuel to burn in a new generating facility. In 1968, coal represented approximately 63 percent of annual electricity generation produced with fossil fuels compared to 10 percent for oil and 28 percent for gas. For the time period 1969 through 1972, coal generation dropped slightly and at the same time the use of oil and gas in electricity generation increased. In 1973, the Arab Oil Embargo occurred, reducing the quantity of oil available, increasing the price of oil, and permanently changing government policy towards building electric generating facilities fired by oil and gas instead of coal. In 1974, the Energy Supply and Environmental Coordination Act authorized the Federal Energy Administration to order power plants and other major fuel burning plants to switch from oil and gas to coal. The use of coal as the primary generating fossil fuel continued to increase throughout the 1970s and 1980s to

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[1] Harvard Business School [22], p. 87.

[2] Ibid, p. 80.

79 percent in 1988. Table 1 and Figure 1 illustrate the use of the various types of fossil fuels from 1968 to 1988.

Coal has become an even more important source of fuel for electricity generation after nuclear power has ended up being an abysmal failure in the United States. Nuclear fueled generating facilities are the only type of nonfossil fueled generation to be built at any significant capacity level (except for previously tapped hydropower sources in the Pacific Northwest). Nuclear power projects' enormous cost overruns, various accidents worldwide, and long shut down times for maintenance problems and safety violations have made, at present, new nuclear generating plants unlikely to be built anytime in the foreseeable future.

For certain states and regions coal use for electricity is more prevalent than in others. Table 2 shows the percent of coal-fired electricity generation by state in descending order -- the highest percent of coal-fired electricity generation (West Virginia) to the lowest (California, District of Columbia, Hawaii, Idaho, Maine, Oregon, Rhode Island and Vermont) with no coal-fired generation. The states with the largest percentage of coal-fired generation are primarily located in Appalachia, and midwestern and western states with significant coal deposits. Coal-fired generation represented more than 50 percent of total generation in 28 states in 1988, signifying coal is, at present, an important fuel used in electricity generation.

Table 1. Coal-fired, Oil-fired, and Gas-fired Generation as a Percent of Total Fossil Fuel Generation, 1968-1988

Year	Coal	Oil	Gas
		(Percent)	
	(1)	(2)	(3)
1968	62.63	9.53	27.84
1969	59.98	11.71	28.31
1970	55.97	14.47	29.56
1971	54.67	16.72	28.61
1972	54.38	19.18	26.44
1973	56.42	20.87	22.71
1974	57.27	20.65	22.08
1975	59.17	20.04	20.79
1976	60.59	20.51	18.90
1977	59.77	21.70	18.53
1978	59.33	22.12	18.55
1979	62.97	17.74	19.29
1980	66.26	14.00	19.74
1981	68.56	11.74	19.70
1982	72.53	8.91	18.57
1983	75.05	8.61	16.33
1984	76.28	6.81	16.91
1985	76.28	6.81	16.91
1986	78.25	7.71	14.03
1987	78.91	6.39	14.70
1988	79.30	7.67	13.03

Note: Generation by petroleum coke included in oil from 1968 to 1980 and 1983 to 1988. In 1981 and 1982, petroleum coke included in coal.

Source: Edison Electric Institute, [14], Table 21, p. 30.

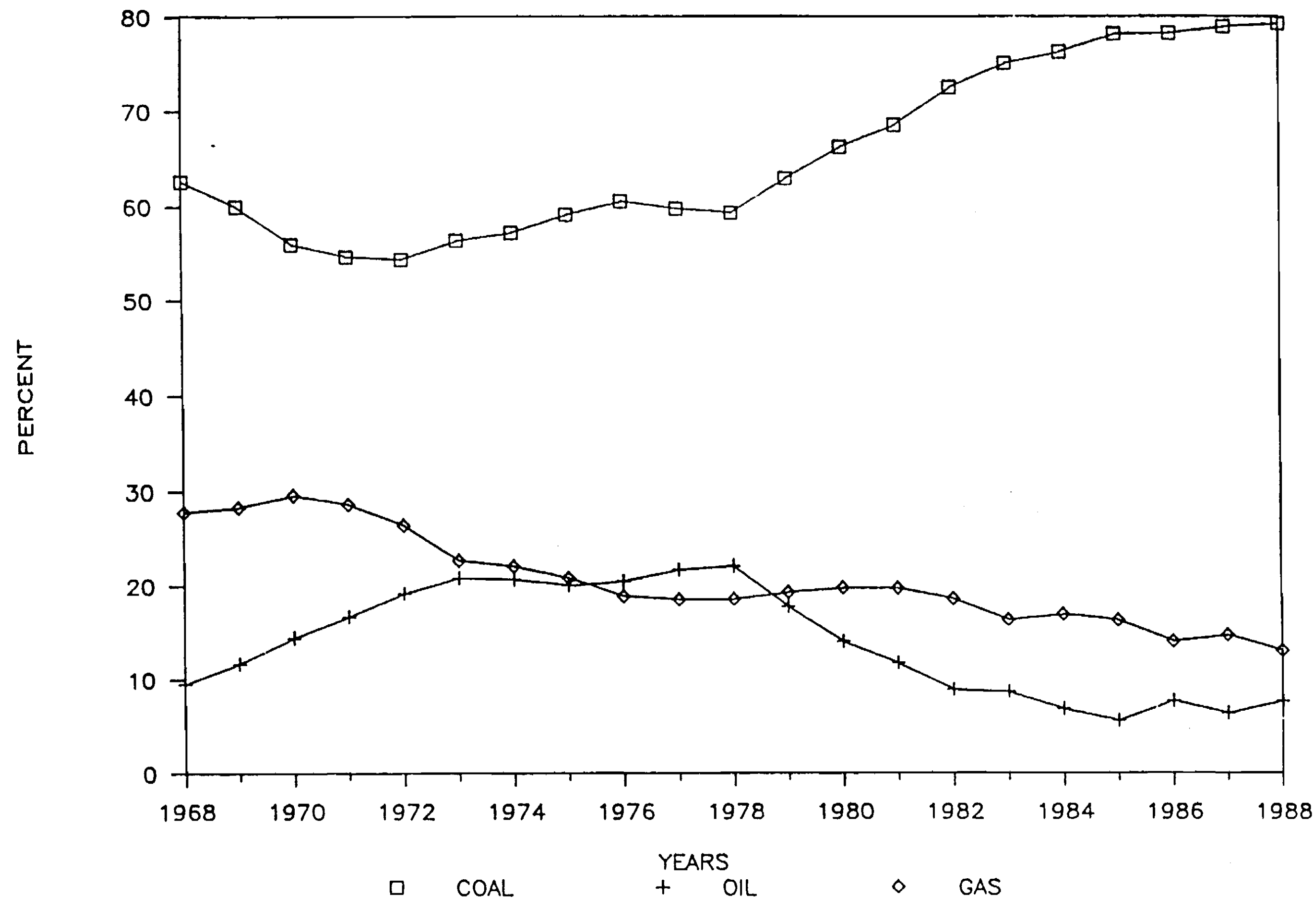

Figure 1. Coal-fired, Oil-fired and Gas-fired Generation as a Percent of Total Fossil Fuel Generation, 1968-1988

Source: Edison Electric Institute [14], Table 21, p. 30.

Table 2. Coal-fired Generation by State, 1988

State	Coal-fired as a Percent of Total Generation (Percent)	State	Coal-fired as a Percent of Total Generation (Percent)
West Virginia	99.30	Oklahoma	55.18
Indiana	98.64	Texas	51.08
Wyoming	97.78	Mississippi	48.03
Utah	97.20	Virginia	47.40
Kentucky	96.61	Florida	46.36
North Dakota	93.05	Arizona	46.12
Ohio	92.36	New Hampshire	45.69
New Mexico	91.35	Illinois	42.97
Colorado	89.99	South Carolina	36.03
Tennessee	85.41	Massachusetts	33.72
Iowa	83.80	South Dakota	33.03
Nevada	82.60	Louisiana	32.46
Missouri	82.11	New York	18.25
Georgia	78.71	New Jersey	18.13
Michigan	77.16	Washington	10.37
Kansas	73.57	Alaska	7.53
Alabama	72.33	Connecticut	5.76
Wisconsin	70.81	California	0.00
Pennsylvania	69.47	District of Columbia	0.00
Montana	66.32	Hawaii	0.00
Minnesota	64.71	Idaho	0.00
Delaware	64.65	Maine	0.00
Nebraska	59.24	Oregon	0.00
Arkansas	58.86	Rhode Island	0.00
North Carolina	58.78	Vermont	0.00
Maryland	57.74		

Source: Edison Electric Institute, [14], Table 21, p. 30.

1.2.2 Solutions to the Acid Rain Problem

Coal is a significant fuel in the generation of electricity and its use has been encouraged by the federal government because it is an abundant and minable resource on the continental United States. However, what solutions are possible to maintain reliability of electricity generation and service at a reasonable cost, clean the air of sulfur oxides and promote national security? There are two general solutions to the acid rain problem: (1) neutralize the acid as it falls to earth or once it reaches the ground (limestoning); and (2) reduce the emissions of the acid producing oxide through the use of scrubbers or other clean coal technologies, nuclear power, renewable energy sources, and conservation and demand side management programs.

1.2.2.1 Limestoning

Limestoning has been demonstrated to be a reliable solution to harmful changes in the pH value of waterways that may be caused by acid rain. In Sweden, scientists have successfully added ground limestone to acidic lakes. The ground limestone neutralizes the acidic water returning it to a less acidic pH level. The Electric Power Research Institute (EPRI) [51] has been testing limestoning in the United States, primarily in the Adirondack region. EPRI has found that adding limestone produces quick and dramatic results and allows aquatic life to reestablish itself in the effected waterway. Although limestoning may neutralize waterways, reversing the damaging effects of the acid precipitation, it does not improve the air quality which would still be laden with sulfur oxides.

1.2.2.2 Fuel Switching

Fuel switching could include converting generators from coal-fired to oil- fired or gas-fired. However, fuel switching in the context of electric utilities' solutions to acid rain is defined as switching from utilizing high-sulfur coal extracted by underground mining to low-sulfur coal which is strip mined. Strip mining is a more efficient mining method, recovering approximately 90 percent of the coal instead of 50 to 60 percent from underground mining.[3] For plants located far from low-sulfur coal mines, shipping costs -- by rail are exorbitant. These transportation costs do not make low-sulfur coal the most economical or least-cost solution for numerous electric utilities.

Switching coal types has both its advantages and disadvantages. The advantage of fuel switching is that it can be easily reversed. If the allowed level of SO_2 emissions for whatever reason are raised, electric utilities can easily switch back to coal with a higher sulfur content -- choosing the least-cost solution. Also for many electric utilities there is a greater assurance of cost recovery of increased fuel costs through their states' fuel adjustment clause (FAC)[4]. Coal switching, from a cost recovery standpoint, may be the <u>best</u> solution for electric utilities that have a FAC and must request capital-cost recovery from a commission that is known for large disallowances on construction projects or a history of holding down retail rates regardless of the implications to the electric utility.

The disadvantages of fuel switching are great and will prevent many companies from using low-sulfur coal as an option to reduce sulfur dioxide emissions. Most utilities are required by their state utility commission to sign long-term fuel contracts. By signing long-term fuel contracts, a utility gains a certain amount of price stability, that results in retail rate stability; the utility by signing a long-term fuel contract also

[3] Harvard Business School [23], p. 87.

[4] A fuel adjustment clause permits a pass-through of increases and decreases of fuel costs (usually a quarterly forecast) to retail customers without a full rate hearing. Usually at the end of a quarter or fiscal year, there is a true-up of forecast versus actual costs.

gains fuel supply reliability that results in reliability in the supply of retail electricity. Some of these contracts will not expire until well after the year 2000, and some utilities would not be able to switch to low-sulfur coal to comply with the 1990 Amendments without breaking their present contracts. Also if a utility switches to low-sulfur coal, it will need to sign a contract with a supplier for long-term provision of the coal. In addition to the costs and problems of negotiating a contract with a new supplier, a utility must worry about transportation reliability and the costs associated with rail or barge transport from the mine to the generating plant. A utility that switches from high- to low-sulfur coal, will more than likely be farther away from the new coal source and more than one type of transportation mode may be necessary (i.e., rail to barge to truck). Also until a long-term contract is signed and approved by the state regulatory commission, a utility may be required to purchase low-sulfur coal in the spot market at a price premium or to purchase the specified contract quantity with no guarantee of recovery of the associated costs.

Another problem that could arise for some companies is that the individual states, to promote the state's or region's coal industry, strongly encourage or require electric utilities to purchase state mined coal. If the mines in the state only contain high-sulfur coal, then some utilities may not have the option of switching to low-sulfur coal since any coal that they purchased would be mined out of state.

1.2.2.3 Technological Solutions

Flue Gas Desulphurization (FGD) or scrubbing is the most common clean coal technology in use today. Approximately 90 percent of SO_2 can be removed using this technology. An alkaline solution is used to "scrub" the SO_2 from flue gases before they are released into the atmosphere. The alkaline solution is usually a slurry of water and ground limestone. The calcium in the limestone combines with the sulfur in the combustion gases to produce calcium sulfate (sludge) which is then collected and disposed of. A scrubber can be added onto a generating unit without having to replace the existing boiler.

The major advantage of scrubbing is that a utility can purchase a coal with either a high-sulfur or low-sulfur content by weight. By installing a scrubber, a utility could continue in its long-term coal contracts and purchase on the spot market without regard to sulfur content, only being limited by other quality constraints. Unfortunately, due to the regulatory climate in some states, a utility may have a difficult time recovering its capital expenditures on scrubbers even if the requirement to reduce SO_2 emissions is federal law. Also, a scrubber adds additional operation and maintenance (O&M) costs which will most likely be passed on to the consumer depending on regulatory treatment. Some of the O&M costs associated with scrubbers include cleaning the scrubber and disposal of the sludge that accumulates in it.

Other technological choices are available to utilities to control their SO_2 emissions. Possible choices at present include atmospheric fluidized-bed combustion and integrated coal gasification/combined cycle conversion. At the present, neither of these technologies is ready for extensive commercial use and may not be ready until well into the 1990s. However, the Department of Energy's (DOE's) Clean Coal Technology Program is attempting to push the commercial operation of these and other viable technologies as soon as possible. The Clean Coal Program, through DOE funding, will provide utilities with the opportunity to try out new technologies that reduce SO_2 and NO_x emissions at a third of the cost of a conventional system.

One of the most promising clean coal technologies selected by the DOE is the "Coolside" Sulfur Removal System which is being demonstrated on an Ohio Edison Company facility. The system is designed to cut SO_2 emissions by 40 to 70 percent.[5] Although this system does not remove as much SO_2 as a FGD system, it avoids the need for capital outlays since it uses the facility's existing equipment. It is particularly useful for older plants whose units were built too close together to install a scrubber. However, this system does produce more solid waste than a scrubber, but it is a dry disposable waste instead of sludge.

1.2.2.4 Nuclear Power

As mentioned earlier, nuclear power plants are no longer a popular choice for capacity additions. Nuclear facilities were to have been an economical source of large scale nonfossil-fueled capacity under the assumption that there would be neither cost nor time overruns. Nuclear plants do not emit the oxides that fossil fueled plants do. They do release however minute amounts of radiation into the surrounding air and water. Also, there is a disposal problem of nuclear wastes in the United States. There have been proposals to build an underground storage facility for nuclear waste from weapons and electric generation plants but these proposal have run into the "Not in My Backyard Syndrome" at each proposed site. Until this problem is solved, nuclear waste will continue to accumulate at the nuclear generating stations. The treatment and protests of the Shorham (Long Island) and Seabrook (New Hampshire) nuclear generating stations illustrate just how negatively nuclear power is viewed in the United States. There have been protests and numerous legal wranglings to keep both

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[5] "Coal Company's 'Coolside' Sulfur Removal System Proven in Ohio Test," [7], p. 11.

Shorham and Seabrook from opening despite the fact that the Northeast may be faced with a severe capacity shortage it the near future.

1.2.2.5 Renewable Resources

Renewable energy sources have not been extensively utilized mostly due to cost constraints. The popularity of and interest in renewables reached its apex in the late 1970s as a solution to the United States' dependence on oil imports. During the 1980s, as oil prices fell and Organization of Petroleum Exporters (OPEC's) power waned, renewables were, in most regions of the country, forgotten or ignored. However, with the latest environmental concerns and the present crisis in the Gulf, renewables are starting to make a comeback. The DOE has assigned more money to the development of renewable energy technologies and energy efficiency in 1990, in an effort to cut electricity costs (mostly through conservation and least-cost planning) and decrease oxide emissions (through renewable technologies). The renewables that have and will continue to see commercial operation include solar, hydropower, geothermal, wind and biomass/solid waste.

Solar electricity production is limited to a very small region of the country, the Desert Southwest, because of the area's constant, intense sunshine and minimal cloud cover. Even in the Desert Southwest, solar power is limited since solar radiation is not continuous and storage and backup systems are required. The initial investment in the capital equipment for the solar generating unit, the storage facilities and backup systems are still prohibitively high even though the fuel, the largest percent of a utility's O&M expenses is free.

Commercial solar generation uses a photovoltaic system that converts sunlight directly into electricity by using thin waferlike panels of semiconductors placed perpendicular to the incoming sunlight. These systems require a large amount of land since the number of panels needed to generate a significant amount of power is tremendous. The capacity of a photovoltaic system is a function of the intensity of sunlight and the efficiency of conversion (which is still low, only 10 to 15 percent)[6], and these factors make power generated by photovoltaic systems very expensive. Besides the capital cost of a solar system, large amounts of hazardous waste are created during the production of photovoltaic systems and a solar facility on average lasts 10 years leaving extensive solid wastes.

Solar systems, as a renewable resource, are defined under the Public Utility Regulatory Policy Act (PURPA) as a qualifying facility (QF)[7], giving them regulatory advantage over small power facilities fueled by conventional sources. At present, to qualify as a QF, a solar project can not use less than 75 percent solar power to generate electricity. This rule means that projects can only be economically justified in Arizona, New Mexico, and parts of Southern California and West Texas.

Within the last year a request has been made to increase the percentage of fossil fuels as an alternative source to 50 percent from 25 percent. By increasing the use of fossil fuels to 50 percent, solar power could be economically feasible in Nevada, Colorado, Utah, Eastern California and parts of Wyoming, Kansas, Oklahoma and Texas. Solar fuel would be the first choice, but if conditions were not favorable then the facility would continue to run as reliable baseload generation by burning a fossil fuel.

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[6] Moran, Morgan and Wiersma [33], p. 646.

[7] A QF is a nonutility generating facility that, under PURPA, is classified as a cogenerator (a unit that produces steam energy) or a nonutility generating facility that uses renewable or biomass resources as fuel.

Hydropower is the kinetic energy of falling water that is most commonly created by damming rivers. Hydropower facilities are expensive to build and because the best locations for hydropower are usually far from where the electricity will be consumed, extensive transmission lines need to be constructed, further adding to the cost and lead time needed for an operational facility. The majority of large hydropower generating stations were built in the Pacific Northwest by the federal government during the 1930s. In recent years, hydropower facilities have been small and built primarily by independent power producers (IPPs)[8] under PURPA regulation rather then by the government or investor-owned utilities. Aside from the capital expense, hydropower has other disadvantages as a primary source of power such as drought, limited locational choices and environmental problems caused by damming the river.

Geothermal energy is heat generated by the earth's interior. Hot rocks come in contact with groundwater forming steam or superheated water, which can then be turned into electricity. Geothermal electricity, from a cost position, can compete economically with conventional generation since the construction and maintenance costs are less. However, geothermal energy has its own environmental problems such as: disposal of the waste water which contains SO_2, hydrogen sulfide, ammonia, boron and saline (more than ocean water); and the most suitable sites tend to be located in scenic areas or National Parks making their development difficult and unappealing.

Wind power facilities can, as with solar systems, be located only in certain geographic regions of the country. To be a consistent and reliable source of generation, the facility must be located in a windy area with as little variability in wind

[8] An IPP is a nonutility company that generates electricity for sale to an electric utility or other customer. The generating units tend to have less capacity than utility owned generating facilities.

speed as possible. The wind speed is an extremely important factor. A doubling of wind speed multiplies the available wind energy by a factor of eight.[9] A wind system is not very efficient -- only extracting 40 percent[10] of the winds's energy. Because of this inefficiency a wind facility needs to install a backup system for times of lulls. A wind facility, although it does not burn fossil fuels has possible adverse impacts on the environment: a high noise level; detracts from the beauty of the landscape; and may kill birds.

Biomass fuel includes wood, ethanol (fermented starches and sugar) methane gas (human and animal waste), municipal and industrial refuse, and sewer sludge. Biomass has become a more popular fuel source in the 1980s as communities faced with shrinking landfill space have begun to build biomass plants turning garbage and waste into electricity. At present, there are two types of technologies to convert waste to energy: (1) mass burning; and (2) refuse derived fuel (RDF). Mass burning is the most common of the two methods in which all refuse is burned rapidly and evenly to produce a superheated steam that in turn can produce electricity. RDF requires that recyclable items be removed from the garbage. What remains is shredded and then weight classified before it is burned for direct electricity generation.

As with the other renewables, biomass is not the perfect solution to environmental problems. A biomass facility may reduce the amount of landfill particles but it pollutes the air, and burning wood has been proven to release carcinogenic materials. There is also a question of resource allocation when ethanol and methane are used as fuels. Should plants high in sugar and starch be allocated for use as an

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[9] Moran, Morgan and Wiersma [33], p. 649.

[10] Ibid, p. 648.

electricity producing fuel or as food? And how should animal waste be allocated, as it is now as a fertilizer, or should it be transformed into a form compatible with a biomass facility?

1.2.2.6 Conservation Measures

Conservation and demand-side management, and purchases from nonutility generators have become important tools in avoiding the construction of baseload plants. These tools are most popular in states where sites are limited, large disallowances were ordered recently for generating plant construction, and where the state utility commission has adopted least-cost planning measures. At the present, regulatory issues concerning both conservation and demand-side management and nonutility purchases are being resolved. In general, state commissions recognize that to make these types of programs successful, incentives need to be introduced so that utilities will aggressively implement programs. Also a utility must be allowed to recover costs and earn a return on demand-side initiatives so that they are able to maintain their financial viability as a publicly held company.

1.3 ECONOMIC EXPLANATIONS FOR ACID RAIN

Despite the fact that acid rain is considered by many people to be a serious problem; legislative bodies worldwide have adopted laws and policies to decrease the emission of SO2; and that there are several proven solutions or alternatives electric utilities can implement to reduce their emissions of sulfur dioxide, they have not done so voluntarily. Economic theory can help explain why firms do not implement pollution controls voluntarily.

1.3.1 Externalities

Air pollution is an externality of electricity production. Externalities are costs or benefits that occur in the production or consumption of a product and whose affects go beyond the producers or consumers involved in the market. In the case of sulfur dioxide pollution, the firm emits oxide pollutants that imposes a cost on society. This cost is an externality to society as a whole, not only where the polluting firm is located but also to regions that the wind transports the pollution. Figure 2 illustrates externalities in terms of marginal social and marginal private costs.

Figure 2 assumes, for illustrative purposes only, that the firm has constant marginal costs. As output increases the amount of externalities also increases -- the difference between the marginal private cost and the marginal social cost.

1.3.2 Property Rights

Sulfur dioxide emissions by electric utilities, as mentioned earlier, contribute to acid rain which is produced in one region and affects other regions due to rain transport of pollutants. Unfortunately, property rights can not be assigned to air itself therefore no one "owns" the air. Firms pollute the air because it is a free good since there are no property rights and therefore no established way to charge for use of polluting the air. The firm continues to pollute since it incurs no costs for its actions. The firm will continue to release pollutants into the air for as long as doing so does not increase the firm's marginal cost. This lack of property rights causes externalities -- the difference between marginal private and marginal social costs.

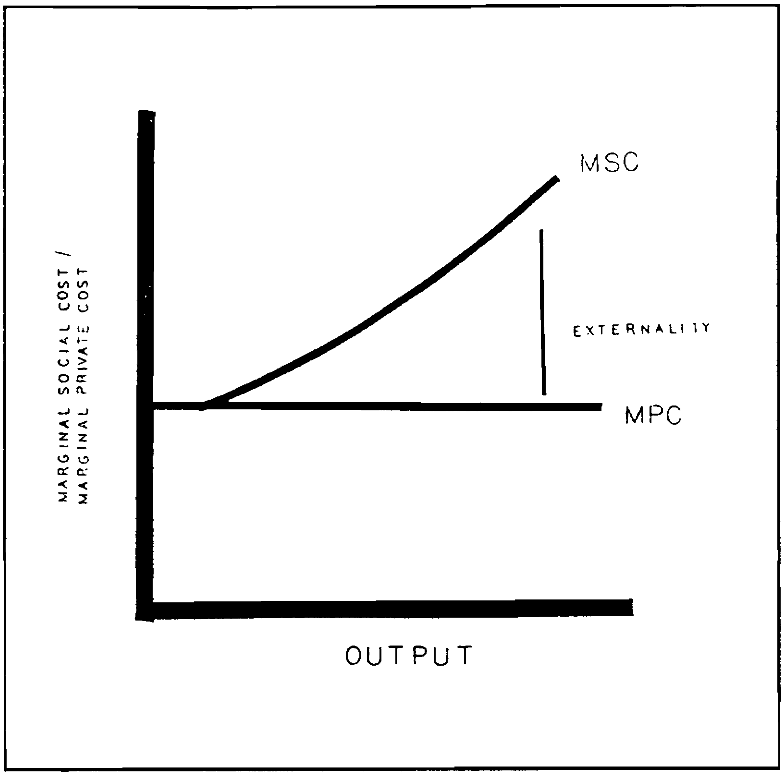
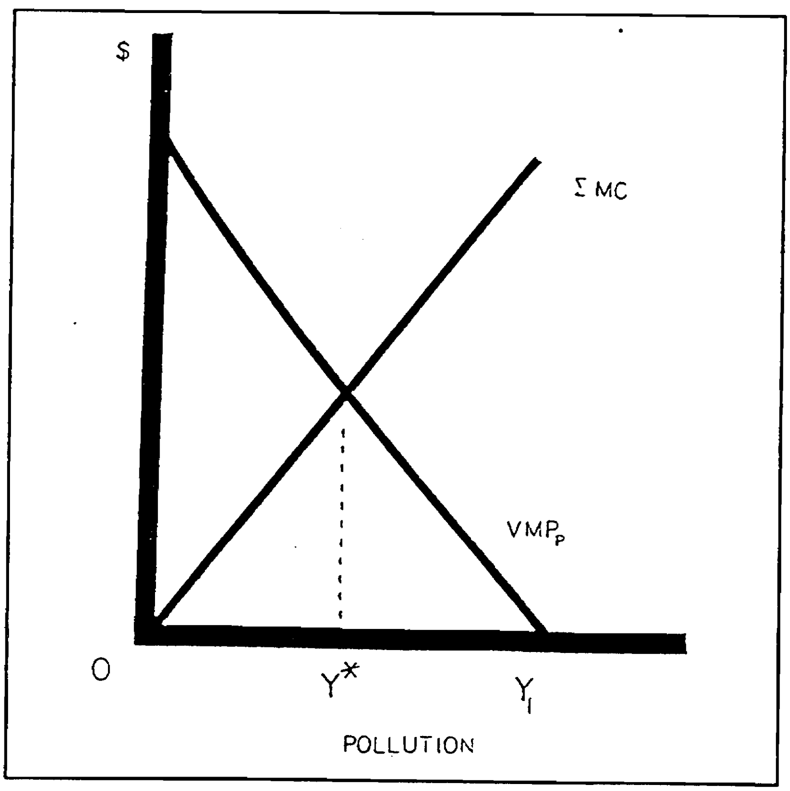


Figure 2. Pollution As an Externality
Source: Fischer & Dornbusch [19], p. 287.

According to the Coase Theorem [6], if property rights are defined, the polluter and those affected by pollution would bargain and move to an efficient position. However, if property rights are not or can not be assigned then the outcome will be inefficient, (not where marginal private cost equals marginal social cost). Figure 3 illustrates the optimal level of pollution if the firm is obliged to pay for pollution rights or to pay for the damage of the pollution and when it is not obliged to do so the level of pollution that will be produced. For purposes of this example assume that the producing firm is competitive in both input and output markets.

As illustrated in Figure 3 if property rights are defined or there are other ways to charge firms for polluting the amount of pollution will be Y^*, where the marginal societal cost (ΔMC) of pollution equals the value of the marginal product (VMP) of pollution -- the benefit to firms of polluting. The VMP = MP_p X P = $(\Delta Q/\Delta Y)$ X P where Q = units of output of a final good; Y = units of pollution emitted; and P = price of the final good. If the firm is not charged for polluting it will pollute up to Y_1 where the benefit of pollution has zero costs. The marginal societal cost will be higher in this case and the level of pollution will exceed the efficient level of pollution Y^*.



<u>Figure 3. Efficient Level of Pollution</u>

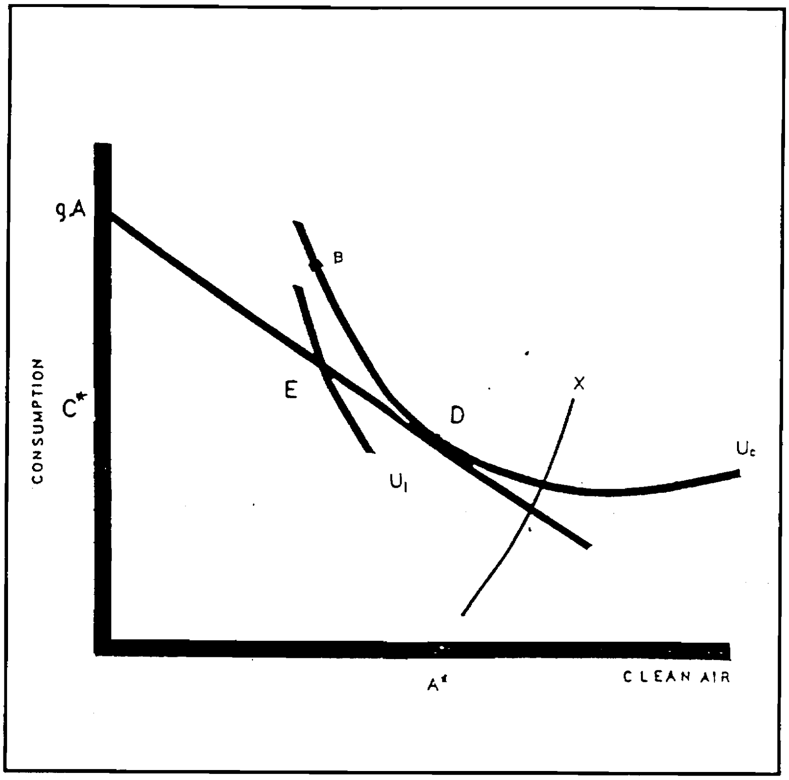
Call & Holahan [6], p. 464.

1.3.3 Efficient Resource Allocation

In the previous sections economic theory explained why firms continue to pollute even though this is not an efficient solution. Due to lack of property rights there is a misallocation of resources. The following iso-benefit curves and nature's budget constraint curve (Figure 4) illustrate the resource allocation problem.

U_0 and U_1 represent the iso-benefit curves. Iso-benefit curves measure how much society is willing to give up of C (consumption) to enjoy more of A (clean air). The U_0 curve to the right of Line X turns upward indicating society can have too much A. Nature's budget line originates at gA and slopes downward. "A" represents nature in its pristine state with no human interference and "g" represents the natural vigor of the air to purify itself from pollutants. The budget line represents the natural capacity of the environment to support consumption and the optimal level of consumption and clean air is point D where the slope of U_0 and the slope of the budget constraint are equal. At this point, the rate society is willing to give up consumption for clean air is at the same rate nature can provide more C at the expense of A.

Point E represents the level of consumption and clean air that is actually attained by allowing the market to allocate resources to C or to A. In this case, more C is consumed since it is underpriced and less A is consumed since it is overpriced. Another means besides the market is needed to correctly price consumption and clean air since it is impossible to assign property rights which would allow the market to allocate resources efficiently.



<u>Figure 4. Society's Iso-benefit Curves and Natures' Budget Constraint</u>

Source: Neher [36], p. 89.

<u>1.4 OBJECTIVES OF THE THESIS</u>

The Amendments will have an enormous effect on coal-fired electric utilities and their customers. Costs to utilities and consumers have been "estimated" by the Environmental Protection Agency (EPA), several of the electric utilities and the Edison Electric Institute (EEI) -- the electric utility trade association. However, the credibility and reliability of these estimates may be questioned since they were asserted as aids in lobbying Congress to include or exclude certain provisions from the Amendments.

Studies have been conducted on previously proposed legislation. One study was conducted by Streets and Veselka [44] on the Aspin Proposal (1983), a piece of tax and subsidy legislation. This study found that the structure of the legislation favored scrubbing (FGD) over fuel switching (from high- to low-sulfur coal) because of the capital cost subsidy portion of the bill. This piece of legislation was never passed.

Another study by Kurish, Penner and Hannon [28] focused on the 1979 EPA directive that ordered all new coal-fired plants to install scrubbers regardless of whether they burned low- or high-sulfur coal. This study found that using western coal with no scrubbers was cheaper than using eastern coal with scrubbers. However, Kurish, Penner and Hannon noted other factors that were not included in the model that could play a role in whether a utility chose to install scrubbers or switch fuel. For example, the problem of escalating coal costs and reliability of coal transports.

This thesis attempts to forecast the effects on residential consumers of coal-fired electric utilities' compliance with the SO_2 provisions of the 1990 Amendments to the Clean Air Act. The forecast is based in part on utilities' historical costs and air abatement choices and their least cost choice for compliance with the Amendments.

1.5 THESIS OUTLAY

The second chapter of the thesis outlines the separate House of Representatives (the House) and Senate acid rain provisions of the 1990 Clean Air Bills and the final bill that was signed into law. Also included in this chapter is a brief history of clean air legislation in the United States. The chapter closes with a discussion of economic theory relating to the efficiency of the various legislative tools used in the past and in the Amendments. These tools include subsidies, taxes, quotas and trading allowances.

The third chapter briefly describes the manner in which electric utilities in the United States are regulated by state commissions. Chapter 4 analyzes the results from the empirical models. The analysis provided includes historical estimates of the relationship between various cost components of service provided by electric utilities and the typical bill paid by residential consumers of these utilities. An analysis is also included of a forecast of the effects of electric utilities implementing least-cost measures to comply with the Amendments. The final section of this chapter summarizes any conclusions reached.

CHAPTER 2

AIR QUALITY LEGISLATION

2.1 THE 1990 CLEAN AIR BILL

In the first five months of 1990 both the U. S. Senate and the U.S. House of Representatives (House) passed a Clean Air Bill. A major as well as controversial component of both of these Clean Air Bills is a reduction of emissions of sulfur dioxide. The Bills specifically target a reduction in SO_2 emissions by public and private electric utilities. By limiting SO_2 emissions, the acid rain problem should be curbed and further damage to forests, waterways and structures should slow down considerably both in the United States and Canada. However, the question still remains -- What will be the cost to the consumer, directly and indirectly of the electric utility industry's compliance with the SO_2 provisions of the bill? All electric consumers' bills will certainly increase due to compliance, varying in degree depending upon what portion of the serving utility's generation is coal-fired, however it is unknown how large these price increases will be.

The U.S. Federal Government has been regulating and researching air quality since 1955. In the past, Congress and federal agencies have considered pollution more of a state or local problem rather than a national one. It was not until the 1970s when air pollution began to be considered a national problem with standards and levels of air pollutants imposed by the federal government instead of state or local governments. Both the Senate's and the House's 1990 Clean Air Bills focus on national air pollution criteria and levels as opposed to setting standards or targeting only specific states or regions for compliance.

2.1.1 Senate Bill S. 1630

Bill S. 1630 [50] (Senate Bill) passed the Senate on April 3, 1990 and called for a total reduction of 10 million tons of SO_2 by the year 2000. This reduction leaves a total SO_2 emission level in the year 2000 of 8.9 million tons. The Senate Bill establishes a SO_2 emission allowance trading program and places a total cap on national SO_2 emissions per year. The reduction of SO_2 is called for in two phases. The first phase, with a 1995 deadline, requires utilities to reduce emissions to 2.5 pounds per million british thermal units (MMBtu). The second phase, with a 2000 deadline, requires utilities to reduce emissions to 1.2 pounds per MMBtu. The reduction of emissions in Phase I and Phase II may be met by any clean coal technology that is published on a list prior to December 31, 1992. Clean coal technology is defined as: "...any technology, including technologies applied at the precombustion, combustion, or post combustion stage, at a new or existing facility which will achieve significant reductions in air emissions of sulfur dioxide..."[11]

For existing and new generating units annual allowances will be distributed to the operators of these facilities, such that total emissions of SO_2 will not exceed an annual rate of 8.9 million tons. These allowances may be sold on the open market to other entities that generate electricity by the initial owner of the allowance. Allowances will also be sold at a cost of $1,500 per ton [adjusted for inflation by the Consumer Price Index (CPI)] by the "Administrator". The total amount of allowances that can be sold at a fixed dollar per ton rate can not exceed 100,000 allowances in

[11] U.S. Senate [50], Sec. 415(a).

a calendar year. Also, allowances sold by the Administrator will not be usable until after the year 2000 and until two years after the calendar year in which it was offered for sale. Before purchasing an allowance, a utility must demonstrate that it is for a particular electric generating unit and that the total number of allowances purchased does not exceed the amount of pollution that will be released as a result of operating that facility.

Beginning in 1995, auctions of allowances will be held at least twice a year. The total number of emission allowances that can be sold at auction to be used in a specific year can not exceed 100,000, but allowances can be auctioned for the current as well as for future calendar years. Any holder of allowances may contribute to the auction and receive the proceeds from the sale of their allowance. The contributing holder may specify a minimum price and payment terms for the sale of the allowance as long as the Administrator deems these to be reasonable conditions.

The Senate Bill also includes a bonus allowance to the dirtiest Midwest plants for early cleanup. Generating facilities in the Midwest are primarily coal-fired and these plants burn almost exclusively high-sulfur coal and will incur the largest costs in the clean-up effort. The bonus allowances are incurred by moving up Phase I (1995) and Phase II (2000) cleanup deadlines by one year. These allowances can be sold, applied to dirty plants or saved for future plant construction. Bonus allowances will also be given to utilities with generating facilities located in states such as California and Wisconsin that have made successful efforts in the recent past to reduce emissions of SO_2. This allows electric generation growth in present low sulfur dioxide emitting states without violating the national 8.9 million ton cap.

The Wirth Amendments included in S. 1630 allow IPPs and QFs that have projects started or those facilities that have signed power sales contracts by December 31, 1989 to be classified as existing units and eligible to receive allowance credits. The amendments also contain provisions to protect state bidding programs[12] from anticompetitive acts associated with credit allowances. These provisions would protect not only the IPPs but also help to insure the continuance of existing bidding programs.

The Administrator may also allocate a total of 80,000 allowances annually to companies that generate electricity at a new renewable energy plant or purchase electricity from a new renewable energy facility operated by another company. These allowances will be allocated on a tonnage amount equal to the number of kilowatt-hours generated or purchased from a new renewable energy plant multiplied by the emission rate of the lowest emitting coal-fired or oil-fired unit of the company applying for the allowance. A new renewable energy plant is defined as an electric generating unit that is under construction by January 1, 1991 and operates primarily on solar, geothermal, biomass or wind sources. Also, the substitution of more efficient equipment in an already existing renewable energy plant that significantly increases the capacity of the unit also qualifies for allowances.

[12] State bidding programs require investor-owned utilities, whether through the utility's initiation or by the state utility commission's directive, to issue a request for proposal (RFP) for independent power sources. IPPs and/or QFs send in bids -- meeting criteria specified in the RFP. Projects are chosen, from the submitted bids, to supply power to the utility. Projects submitted in the bidding process are usually not built and in many cases not sited when they are selected by the utility. Construction usually begins once the bid is awarded. Bidding programs have become a popular method of obtaining needed capacity without the investor-owned utilities having to build additional generating units.

2.1.2 House of Representatives Bill, H.R. 3030

Bill H.R. 3030 [48] was passed on May 23, 1990. It included an acid rain provision directed at electric utilities, however there are some differences between the House Bill and the Senate version. The House Bill is also divided into two phases but the timing of the phases is different from the Senate Bill. Phase I begins on January 1, 1996 and Phase II commences January 1, 2001. The first phase emissions are at a rate of 2.35 pounds of SO_2 per MMBtu and the emission rate for Phase II is 1.2 pounds of SO_2 per MMBtu. At the end of Phase II, the total emission rate in pounds per MMBtu for both the Senate and House Bills are the same. Both Bills are structured around an annual emissions cap and allowances that will be sold in the open market and through a federal government sponsored auction. These allowances will distribute the total quantity of permitted emissions among the various electric utilities. The details of the allowance and auction systems do differ in the Senate and House Bills.

In both Phase I and Phase II of the House Bill, the Administrator will issue allowances to electric generating facilities. By the second phase, the total maximum allowance will be 8.9 million tons of SO_2 per year. A reserve of 100,000 allowances will also be formed. These allowances will be sold at a cost of \$1,500 each and this price will be adjusted for inflation by the CPI. A reserve of 25,000 allowances during the first 10 years of the program will be sold for \$750 per allowance to companies with units emitting less than 0.9 pounds of SO_2 per MMBtu. The House version includes an auction system of allowances as well. Operators may submit up to 50 percent of their allowances to the Administrator for auctioning. The owner will not be permitted to set a minimum price for the allowances they wish to sell in the government sponsored auction for any of their allowances that are designated for future calendar years. However, they will be allowed to set a minimum price if the allowance is good for the present year. The auctions will begin in 1993 and be open to anyone who wishes to purchase allowances.

The House Bill also provides extra allowances to utilities that reduce their SO_2 emissions by conservation methods or through the use of renewable resources. There will be a single allowance issued to a utility on a first-come first-serve basis during the time period January 1, 1992 through January 1, 2001 for reduction of emissions through either conservation or through the use of renewable resources. A total of 400,000 tons of allowances will be reserved for this purpose. The House Bill also gives IPPs the right to purchase allowances at a fixed price of $750 per allowance from the reserve or through the auction system.

2.1.3 Opposition to the Bills and Rejected Provisions

The 1990 Clean Air Bills were not passed by the House and Senate without a great deal of compromise and controversy. The most controversial aspects of both Bills were the banking of emission credits and any type of cost-sharing provisions. These provisions created controversy because they were beneficial to specific sectors of the electric utility industry and geographic areas. Investor-owned utilities in the Midwest and the southern regions of the country stand to benefit the most from these provisions and generating facilities in the Northeast and the West the least.

Some states vigorously opposed the banking of emission credits because they felt it would place them at a severe disadvantage when new generating facilities were needed in the future. These states, at the present have little or no coal-fired generation or already have stringent air quality standards in place. Credits are to be handed out based on present emissions of effluents; those states with a higher emission rate would receive more credits. The electric utility companies that would be given the credits could then effectively reduce their output of SO_2 by using scrubbers or other approved technologies, banking their credits for use in the future when new capacity was needed. Companies that did not have generating facilities that emitted SO_2 or had plants that emitted low levels of SO_2 would not be given as many credits as companies in high emitting states. Therefore they eventually could not bank allowances for use when demand increased in the future. They would not be able to construct coal-fired facilities or any other type of facility that emitted SO_2 to meet future demand increases or as a substitute for a plant retirement. Also, IPPs and QFs were concerned that they would not be able to obtain credits to build future facilities that could be fossil-fueled.

The Senate Bill provided a provision that a utility could not hold or buy more emission allowances than was needed to operate a specific generating facility. A utility therefore could not bank its emission credits for future use while other utilities may need the credits to maintain system stability and reliability if their reserve margins decrease due to an increase in demand. In both the House and Senate Bills, the utility is free to sell any excess credits on the open market or through the government auction process. The market for excess credits should permit utilities that need to construct new facilities the ability to do so with whatever fuel they choose. Also, the Administrator will sell, at a fixed price and through auctions, preset amounts of emission credits for each calendar year that can be used for new and old generating facilities. Both Bills also made specific exceptions for IPPs, QFs and municipal utilities in the dispersion and selling of emission credits. This was done to insure that there would continue to be diversity and a certain level of competition in the generating sector of the electric utility industry.

Various cost-sharing measures were proposed ranging from emission taxes to generation fees. In principle, a cost-sharing provision would tax all emissions of SO_2 and the money collected would be used to aid companies or regions that suffered an adverse economic impact due to the regulation. The Sharp Package proposed by Representative Philip Sharp (D-Indiana) was opposed by the Administration as well as by various special interest groups. This package required a fee for industrial SO_2 emissions (not just for electric utilities) and rewards to plants that attained an early compliance. Another package was put forth by Representative Pete Stark (D-California). He proposed an emission tax of $0.15 per pound of SO_2 emitted beginning in 1991 and increasing to $0.45 per pound in 1997. The rate per pound would increase thereafter at the rate of inflation. In this package, there was no explicit mention of the tax being used for cost-sharing purposes.

The Administration opposed any type of cost-sharing provision or scheme that involved a tax of any kind. The EEI, a coalition of investor-owned utilities, strenuously objected to any type of taxation since in the end the ratepayer would have to pay twice -- once for the installation of pollution control equipment and again for the tax on effluent emissions. Nonutility generators (QFs and IPPs) object to a fee or tax because they will not be able to pass it on to their customers the way a utility could. Most nonutilities sell their generation either at regulatorly set avoided costs[13] or through a negotiated contract that fixes the price for the length of the contract and

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[13] Avoided costs are the costs that an investor-owned electric utility would incur if it constructed capacity instead of purchasing the capacity from a nonutility generator.

uses escalators to reflect changes in fuel costs and inflation. However, several groups were in favor of a tax on utility emissions. The American Public Power Association, a trade group representing public utility companies (municipalities), favored an emission fee as long as the fee would be used for cost sharing. Other supporters of an emissions fee included the National Life Federation, the National Clean Air Coalition, World Resource Institute, the Environmental Defense Fund and Greenpeace.

Another form of cost-sharing or subsidy proposal was put forth by Representative Robert Wise (D-West Virginia). His concern was the welfare of coal miners in his state that are employed in the production of high-sulfur coal. He proposed an addition to the Clean Air Bill to use an emission tax to help miners of high-sulfur coal in job retrainment. President Bush threatened to veto any bill that contained a cost-sharing provision related to the miners. This package was also never included in either version of the Clean Air Bill.

2.1.4 Final Bill Provisions

The final Clean Air Bill (the Bill) was signed into law in November 1990 by President Bush. The sulfur dioxide provisions are very similar to the Senate version. There are two phases: Phase I commences on January 1, 1995; and Phase II begins on January 1, 2000. The maximum amount of emissions permitted is 8.9 million tons of SO_2 per year. Utilities may reduce their emissions using any qualifying Phase I technology. A qualifying technology reduces emissions of SO_2 by 90 percent.

Allowances issued to utilities based on their 1985 generation capacity plays a major role in the Bill. Utilities will be permitted to trade allowances subject to rules to be formulated in the future. The allowances that are issued or traded can only be used for the calendar year for which they are assigned. The Administrator shall establish a reserve of allowances in the amount of 50,000 tons per year. These allowances will be sold at $1,500 per ton, adjusted by the CPI beginning in the year 2000. The Administrator will also conduct allowance auctions beginning in 1993 and the allowances will be sold to the highest bidder.

Allowances will also be issued for utilities that utilize accepted conservation methods and renewable energy sources or QFs. Only conservation programs and renewable energy generation constructed in the time period 1992 to 2000 are eligible for these allowances from the Administrator by using qualifying Phase I technology to reduce emissions. These extra allowances can be earned in 1997, 1998 and 1999.

The provisions of these Amendments are not to interfere with either competitive bidding programs or the antitrust laws. An IPP that proposes to construct a new power production facility that requires allowances; intends to apply for financing after January 1, 1990 and before the first allowance auction in 1993; and has made a good faith effort to purchase allowances from electric utilities at a price of $750 per ton and was unable to purchase any shall receive an allowance guarantee from the Administrator.

2.2 HISTORIC AIR QUALITY LEGISLATION

The 1990 clean air legislation is not the first attempt by the federal government to regulate either the level of air pollutants or air quality in the United States. The following is a brief history of attempts by Congress to regulate air quality.

2.2.1 1963 Clean Air Act

The first federal air pollution legislation was adopted in 1955. It provided funding for research and reporting of air quality nationwide. However, it did not set any type of standards or regulations for the nation, states or localities. In 1959, the act was extended for four more years. At this time, air pollution was considered to be a local or state problem and not a federal one.

The first Clean Air Act was passed in 1963. This act gave the federal government through the Department of Health, Education and Welfare (HEW) enforcement powers over air quality. The HEW was authorized to call a conference on air pollution problems in a particular region or airshed. If air pollution or air quality problems in the given region or airshed were not satisfactorily solved during the conference, then the HEW had the right to hold hearings on the problem. As a last resort, the HEW could bring court action against a polluter. Enforcement was not rigorous under this Act; only 11 conferences and one court case were held during the time period 1963 through 1970.

2.2.2 1967 Air Quality Act

The Motor Vehicle Act was instituted in 1965. This Act authorized the HEW to set emission standards for automobile emissions. In 1967, the Air Quality Act was passed. The HEW was to issue criteria on levels of pollutants in the atmosphere. Ninety days after the HEW published its criteria each state had to file a letter of intent to comply. The states then had six months to implement plans to control their air pollution and if the state did not file a plan to comply, the Secretary of the HEW could set a plan for the state. The act also greatly expanded federal research efforts on air quality and it set national standards for auto emissions. Once again, the act was not rigorously enforced. The HEW was slow to issue criteria for pollutant levels and once criteria was issued the HEW was slow to act to make sure the criteria was met. By 1970 not one state had a full scale plan in effect.

2.2.3 1970 Clean Air Amendments

The Clean Air Amendments were enacted in 1970. These amendments established the EPA and gave it the power to set limits on the emission of hazardous pollutants. The EPA established two standard levels for air quality: primary and secondary.[14] The states were to submit plans to the EPA for approval that would meet both primary and secondary standards. The amendments also gave the EPA the power to set new performance standards. The new performance standard amendment set the emission level for new facilities at an amount no greater than what is attainable with proven emission control technology. For power plants at this time, the only proven technology for decreasing SO_2 emissions was fuel switching which was suspended for a period due to the Arab Oil Embargo. The oil embargo also contributed to the promotion of coal over oil or gas in electricity generation. The 1974 Energy Supply and Environmental Coordination Act authorized the Federal Energy Administration to order power plants to switch over their facilities from gas-fired or oil-fired to coal-fired in order to decrease reliance on imported fuels.

2.2.4 1977 Clean Air Amendments and the 1978 Industrial Fuel Use Act

A 1977 amendment to the Clean Air Act was aimed at the prevention of a significant deterioration of existing air quality levels. What this essentially did was to make the siting of new generation facilities more difficult and time consuming. Before a permit is issued there is a one-year pollution control monitoring with public hearings and an increased chance of litigation.

[14] Primary air quality standards are the maximum exposure levels that can be tolerated by humans. Secondary air quality standards are the maximum level of air pollutants allowable to minimize harmful impact on materials, crops, visibility, personal comfort and climate.

By 1988, there were 151 scrubbers in operation, 64 percent are on plants operated by investor-owned utilities.[15] There are 18 scrubbers under construction or planned in 1988 and 72 percent are on investor-owned facilities.[16] This compares to 72 scrubbers operating in 1980 of which 69 percent were investor-owned.[17] The reason for scrubbers extensive use in the 1980s is because in 1978, the Industrial Fuels Use Act further discouraged the use of oil and gas in electric generating facilities. This Act prohibited the construction of new gas-fired and oil-fired facilities. In 1987 Congress amended the Fuel Use Act to permit gas-fired electric generating stations as long as the facilities were capable of burning coal as well.

2.2.5 1980 Air Quality Legislation

The 1980s brought a wave of proposed air quality legislation in Congress, although nothing was ever passed. Among them was the 1983 Aspin Proposal (H.R. 4483) introduced by Representative Les Aspin of Wisconsin. This bill proposed a combination of a limit on total emissions, a tax on excess emissions, a rebate for an excess reduction of emissions and a subsidy for utilities that choose a technology solution over fuel switching. An acid deposition control fund would be established at the Treasury. Sulfur dioxide taxes would be put into an account and rebates and subsidies would come out of this fund. Other bills proposed during this time period did not include economic incentives for reduction of emissions but they did tend to favor either fuel switching or the installation of scrubbing technologies.

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[15] National Coal Association [35], pp IV-1 through IV-6.

[16] Ibid, pp IV-7 through IV-8.

[17] Ibid, pp IV-1 through IV-6.

2.2.6 The WEPCO Decision

In 1988 Wisconson Electric Power Company (WEPCO) proposed to renovate an aging coal plant. The EPA, in October 1988, ruled that if WEPCO proceeded with its renovation that the plant would be reclassified as a new-source plant. As a new source plant, the renovated WEPCO unit will be required to install a scrubber. This decision is being appealed. If the EPA ruling is upheld it will effect whether utilities will renovate older plants or build new generating capacity to meet their needs. If pollution control equipment is required, the cost of renovation will increase dramatically and this may no longer be the least-cost solution. In the final Bill, a reconstructed or repowered unit will be considered an existing unit and not a new source.

2.3 ECONOMIC EFFECTS OF VARIOUS LEGISLATIVE MEASURES

Regardless of what tools the legislative or regulatory body uses to curb air pollution a cost-benefit analysis is needed to determine the optimal level of pollution. Figure 5 shows the cost-benefit analysis for air pollution.

The marginal benefit curve (MB) slopes downward -- the higher the level of pollution the more benefit is incurred with a decrease in air pollution. As the air becomes cleaner the benefit of clean air is lower than when the air was dirtier. The marginal cost (MC) curve behaves in the opposite way as the MB curve. The costs of achieving cleaner air when the air is dirty is less than when the air is cleaner -- closer to the 100 percent clean level. The optimal level of pollution is at Q_o where MB equals MC. Unfortunately, these curves are difficult to measure in actuality and only a good estimate can be made.

2.3.1 Compliance Under the 1979 EPA Directive to Install Scrubbers

The EPA uses direct regulation to help maintain a certain level of ambient air pollutants by requiring all new electric generating stations to install scrubbers. This requirement has the effect of slowing down, almost to the point of completely arresting research on developing more efficient technologies. To help initiate research on pollution control devices, the DOE has implemented the Clean Coal Technology Program and through this program research is once again being conducted to create technologies that will reduce pollution, hopefully at lesser cost.

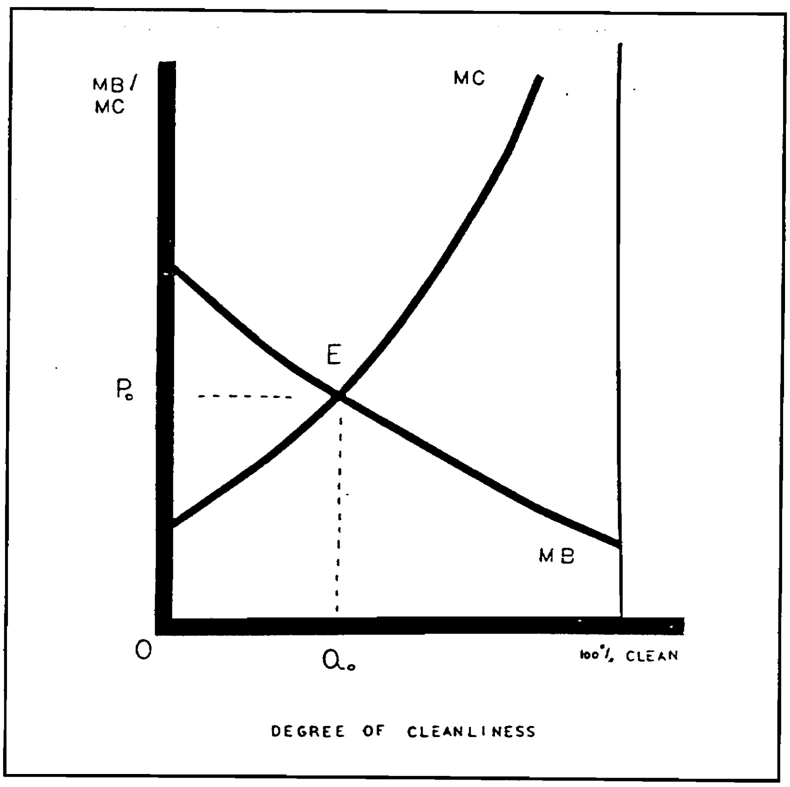

Figure 5. Cost-Benefit Analysis for Air Pollution

Source: Fischer and Dornbusch [19], p. 290.

After the regulation was issued, many of the new coal-fired generation was built in western states where low-sulfur coal is mined. The utilities were forced to overcomply because they chose low-sulfur coal which for these utilities is the least-cost solution and by installing scrubbers. The utilities incurred greater costs than necessary to emit low levels of SO_2 and these costs are paid for by the ratepayers.

2.3.2 Subsidy of Technological Solutions

The Aspin Bill provided a subsidy to utilities that chose to implement Clean Coal technologies instead of switching coal types. The subsidy would shift the demand for these technologies, increasing quantity supplied and the price of the technologies. Although the backers of this bill stated that the subsidy as well as the rebate for reduced emissions would be funded through an emissions tax, the subsidy would inevitably be at least partially funded through the federal government budget. The subsidy could also have distorted utilities' selection of the method of compliance -- some companies would have otherwise chosen to switch coal types and instead installed expensive equipment to reduce emissions. The ratepayers would pay twice -- once through federal taxes and again in their electric rates.

2.3.3 Emission Taxes

An emission tax would set a price for pollution. The utility could continue to pollute at the same rate and pay the corresponding tax, or the utility could lower its pollution and pay a smaller amount in taxes. Both the Aspin Bill and the proposed Stark amendments to the House Bill proposed an emissions tax. An emissions charge could permit the regulator to equate the utility's VMP to the MC curves with knowledge of the MC curve and no knowledge of the VMP curve in Figure 2, Section 1.3.2. Figure 6 illustrates how this will occur.

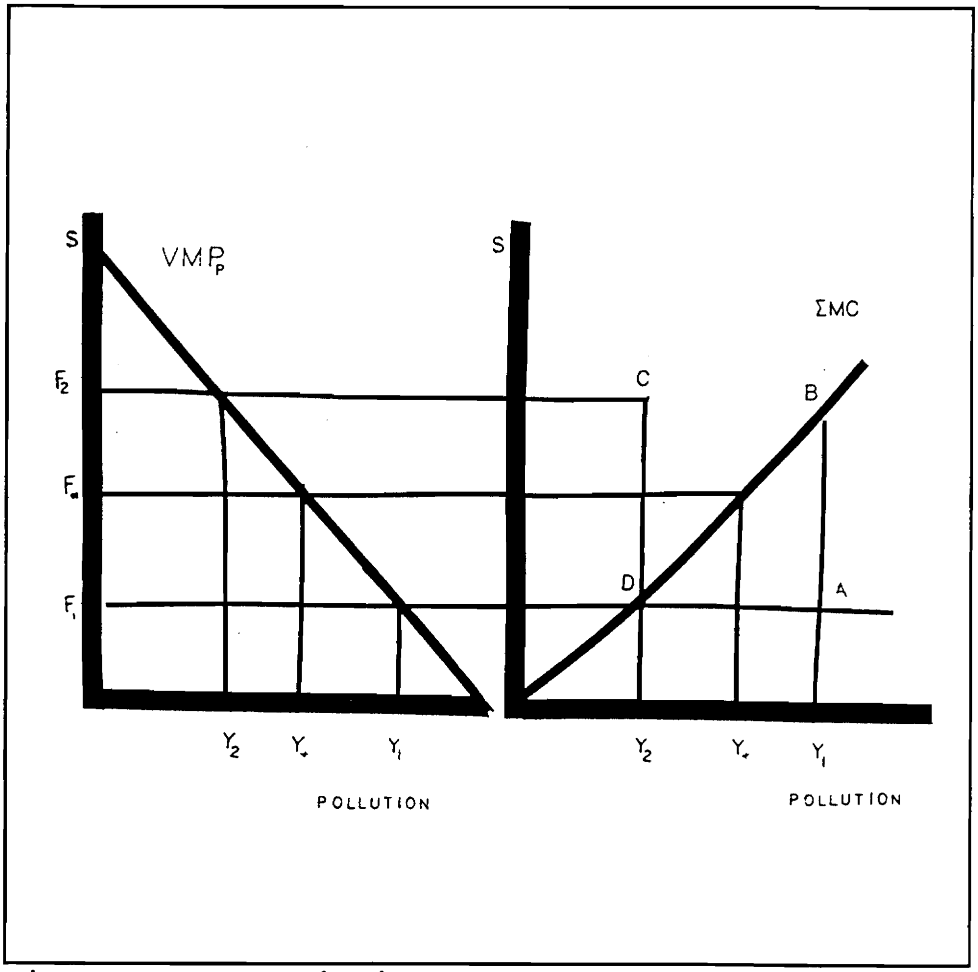

Figure 6. Emission Taxes and the Efficient Level of Pollution

Source: Call & Hollahan [6], p. 471.

If the regulator sets the initial charge at f_1, the firm will pollute to Y_1. At Y_1 the MC curve is higher than the fee by the amount A to B. The government would then raise the fee to f_2 and the firm would pollute up to Y_2 however the MC curve is less than f_2 by the amount C to D for this level of pollution. The regulator would continue to set charges between these two points until the fee level intersects the VMP and MC at the same level of pollution -- the efficient solution. This optimal amount of pollution is at Y^* with a fee of F^*. An emissions tax, however will not bring about the proper solution if the entity setting the fee is driven by other objectives than equating VMP and MC.

2.3.4 Quotas

The Amendments are principally based on quotas of SO_2. The Bill sets the quota on the amount of SO_2 emissions that electric utilities can emit annually. The Administrator then gives allowances to each utility -- representing the quota each utility's quota of emissions. This particular piece of legislation does not constrain the utility in how it should meet its quota but a constraint could easily be used in combination with a quota system.

The major problem with a quota is that the regulator has to estimate each firm's VMP curve. If the estimate of the VMP is greater than the actual VMP a higher quota will be set and more pollution will occur than at the actual VMP. The reverse holds true if the estimation of the VMP is less than the actual VMP. In this case less pollution will occur then is actually acceptable. Figure 7 below illustrates this problem.

VMP_p^1 is an overestimate of the actual VMP curve. In this case the quota is set at a higher level then it should be and firms will pollute Y_1. VMP_p^* represents the actual VMP curve, and Y^* is the efficient level of pollution. Also quotas may not reflect the efficient level of pollution, where MC equals VMP even if the VMP and MC curves are known to the regulator. Quotas could be subject to the influences of special interest groups, bargains made and political graft.

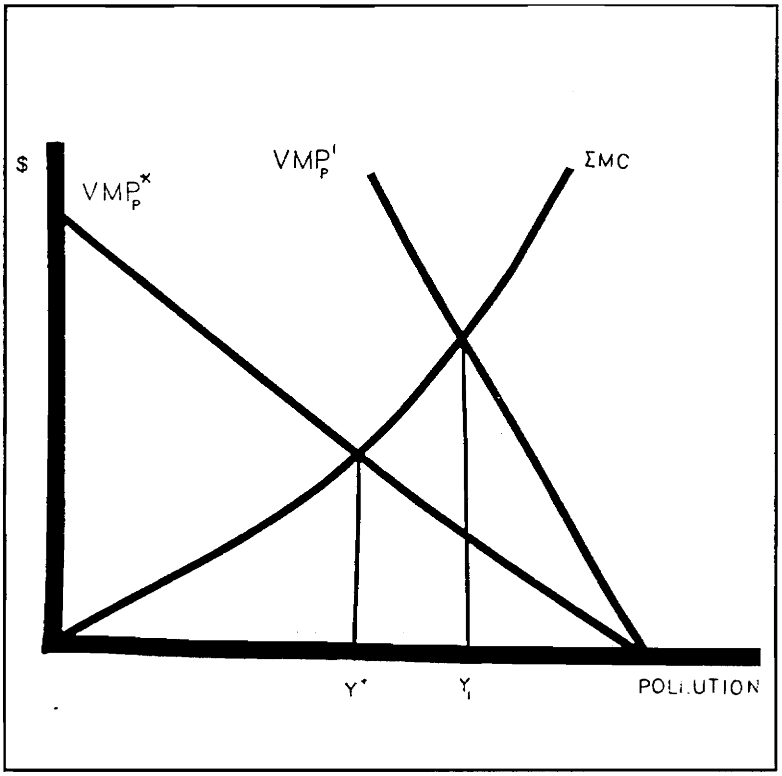

Figure 7. Quotas and the Efficient Level of Pollution

Source: Call & Holahan [6], p. 472.

2.3.5 Allowance Trading

The allowance trading and banking provisions of the Bill were controversial. Arguments were made for and against these provisions and allowance trading and banking were permitted in the final Bill.

Among the arguments against trading was that utilities would hoard allowances and not be willing to sell them to other companies that needed allowances to construct generating capacity. Also, those who opposed trading allowances stated that these provisions do nothing to make the electric utility industry more competitive, and would in fact increase the power and position of the larger electric utility companies.

These arguments are not accurate for numerous reasons. First, addressing the hoarding problem, electric utilities are regulated by state commissions. If the state commission permits the utility to trade allowances then the utility's decision to trade or not trade comes into question by the commission. Also, there are other ways for utilities to obtain allowances besides purchasing them from other utilities. Allowances can be purchased from the Administrator at a set price, through a government run auction, by reducing own emissions below the quota level for existing plant, and utilizing conservation and renewable energy source projects. IPPs have their own procedures for obtaining allowances so they are not in any way cut off from obtaining allowances.

The market for allowances is a method of obtaining a price for SO_2 emissions. A utility can pay the market price by trading with utilities for allowances or bidding a high enough price at government sponsored auctions. If the price is too high the utility will choose another option, that produces an equivalent amount of generation (or an equivalent reduction in consumption). Utilities in the United States are not limited to solely coal-fired generation, and should not turn to this method simply because 79 percent of units are coal-fired. Also there is the possibility, since Congress has permitted electric utilities latitude in choosing the method used to reduce their emissions, that technologies may evolve that could completely eliminate SO_2 emissions at a reasonable cost. This could give utilities even greater options to satisfy increased demand.

Second, the trading provisions were not meant to create competition in the electric utility market. Trading is to be used as a market guide to the price of SO_2 pollution. As long as the rules and regulations to be promulgated in the future are not constructed to give preference to larger utilities then trading will not harm whatever competition does exist in the electric utility industry. Trading should not be disallowed simply because it does not further competition since that is not its purpose.

Allowance trading is not a new phenomena in air pollution policy. In 1977, the EPA began to implement a variety of methods that allow substitution of emissions between sources. Although these methods do not exactly mirror emissions trading as represented in the Bill, they did create an emission allowance market. Hahn and Hester [20] evaluate the impact of the EPA's emissions trading program. They conclude from their research and from a review of the literature that : (1) at least in theory, allowance trading promotes more cost-effective air pollution regulation; and (2) cost savings from a market system are large.

CHAPTER 3

ELECTRIC UTILITY RATES AND STRUCTURE AND CORRESPONDING DATA

3.1 ELECTRIC UTILITY RATES AND STRUCTURE

Electric utilities, whether investor-owned, municipals or cooperatives are regulated in the United States. The state commissions regulate service and rate standards for retail use and the Federal Energy Regulatory Commission (FERC) regulates wholesale service and rates. The state commissions have restricted regulatory power over municipal and cooperative electric utilities, and the amount of regulatory power the commissions can exercise varies from state to state.

3.1.1 Legal Precedent of Electric Utility Rates

Although there are numerous theoretical explanations and reasons given as to why public utilities should be regulated, none of these give clear practical ways to set rate structures or to guarantee a recovery of costs. Rate structure and recovery of costs has instead been based on court decisions in various public utility cases. In the Supreme Court decision, *Smythe v. Ames* (1898), a number of factors were listed that a commission should consider in determining the value of a regulated company's property, however, the court did not suggest any weights for these factors. A similar decision was handed down in the *Bluefield* case of 1923. The Court found that a utility was entitled to a return that was comparable to returns being earned by nonregulated companies at the same time, in the same geographical region and with a similar risk level. The *Hope Natural Gas* case (1944) decision stated that the method of determining the rate base and the rate of return should be left up to the state commissions, and the courts should only interfere if there was an obvious instance of injustice.

There are other important regulatory areas, such as the prudent investment test, nonconfiscatory rates and the used and useful criterion that have a legal precedent as well. Judge Brandeis argued in the *Southwestern Bell* case (1923) (and in many later decisions) that the proper measure of value of a utility's costs are all costs that are determined to be prudent -- the original cost minus any fraudulent, unwise, extravagant or unnecessary expenditures. A prudent investment method would be stable and not dependent on the uncertain opinions and whims of commissions and the courts. Today, in most states, the prudent investment method is used in determining what should or should not be included in rate base.

Recently, with large, expensive plant additions whose capacity is unneeded and an increasing number of nuclear plants shut down for safety reasons, numerous commissions have either switched from a prudent investment standard to a used and useful standard or retained the prudence standard but made recovery contingent on the condition that the facility is used and useful in the service of the retail customers. In general, the used and useful standard is utilized on a case-by-case basis. If the facility in question is not found to be used and useful, a disallowance will occur regardless of whether the investment was found to be prudent at the time it was made.

The Court, in the matter of rate of return, has dealt almost exclusively with the question of confiscation. In general, the courts have found that the earnings of a public utility cannot be set too low as to confiscatory, thereby violating the constitutional guarantees of "due process" and "equal protection of the law." However, the Court also argued that a public utility is not guaranteed a rate of return. Public utilities should be protected against arbitrary behavior of the commissions and the courts but not from normal business risks and economic forces.

3.1.2 Rate Structure

There are two major components that comprise a utility's rate structure: operating expenses and return on investment. Operating expenses include: fuel, other operation and maintenance costs, taxes, depreciation and amortization expenses (return of investment) and gains or losses from the sale of electric utility plant. The company's rate base is multiplied by the rate of return (ROR) to determine the utility's return on investment.

Historically, the determination of a utility's rate base has been extremely controversial. The rate base is the value of a utility's property that is used and useful in the public service minus accrued depreciation. Most state commissions disallow the inclusion of construction work in progress (CWIP) in the ratebase although some do permit recovery of CWIP through rates. The determination of what should be included and the method of depreciation has always been a problem for commissions. However, the major controversy in determining an electric utility's rate base has centered around the choice of original cost versus reproduction cost.[18] Most of the state commissions use original cost valuation as does the Federal Communications Commission and the FERC.[19]

[18] Original cost is the cost of installing the original plant and equipment plus any additions when the plant, equipment or additions are first placed into service. The reproduction cost method values the cost of the plant, equipment and additions at estimated price levels prevailing at the time the facilities are being valued.

[19] Bonbright, Danielson and Kamerschen [4], p. 229.

The ROR enables the utility to meet its cost of capital, both fixed charges and reasonable dividend requirements. The utility's total invested capital is totalled at 100 percent and is divided, by the commission, into percentages representing capital secured by the issuance of: (1) funded or long-term debt; (2) preferred stock; and (3) common stock. These ratios are applied to the annual cost of the capital to yield a weighted average ROR on capital. This weighted ROR is the figure that is used to calculate a utility's return on investment. Factors that influence a commission's choice of capital structure and cost of capital include: preferences of investors; equity financing; risk; and inflation.

The primary objectives of a sound rate structure (the billing schedule) are revenue requirements (production-motivated or financial need) and the optimum use of the product -- consumer rationing and fair cost apportionment among customers.

The ideal solution to meet these objectives is rates that are based on cost of service. Although electric utility rates deviate less than other utility rates from the cost of service, they still do deviate. There are numerous problems with utilizing a cost of service standard including an excessive complexity in the relationships between costs and customers; costs that can not be easily subdivided between numerous customers or between a few customer classes and also incremental costs are nonadditive and therefore would not permit the utility to recover all of its costs.

3.1.3 Electric Utility Tariffs

Today, electric utilities use either a two-part tariff or a three-part tariff to distribute costs among their customer classes. The two-part tariff consists of a demand charge and an energy charge. The demand charge is based on the maximum (i.e. 30-minute) demand of the customer during the previous time period (usually the last 12 months). The rationale behind the demand charge is that it reflects charges associated with plant capacity. Plant capacity must be planned and constructed by the utility based on the amount of demand on the system. The demand charge reflects the cost of additional capacity to serve a customer's load. The energy charge reflects the cost of producing the kilowatt-hour of energy consumed.

A three-part tariff consists of demand and energy charges as well as a service charge. This type of tariff is more common today than a two-part tariff. The customer charge reflects the costs incurred, by the electric utility, to serve a given customer. This cost will be incurred even if the customer, for a given month, does not use the service. Examples of these customer costs are the expenses associated with local connection facilities, metering equipment, meter reading, billing, accounting and a portion of the distribution system. Often, in a three-part tariff, the demand charge is uniform instead of a block rate as it is in the two-part tariff. The demand and energy charges may also differentiate on a peak/off-peak basis for commercial and industrial customers although rarely residential customers.

Time-of-use (TOU) rates have become increasingly popular in recent years. Days are divided, by the state commission, into peak and off-peak periods. Weekends and holidays tend to be counted only as off-peak periods. By charging a significantly higher demand and/or energy charge for peak periods, it is hoped that load will be reduced during the peak period and increased during the off-peak period (usually at night). By spreading out the load, the amount of additional capacity that will need to be built will be reduced. In many states, TOU rates are applied solely to industrial and commercial customers. However, many commissions wishing to encourage conservation have implemented, usually on a trial basis, residential TOU rates.

CHAPTER 4

THE STATISTICAL MODEL: ANALYSIS AND FORECAST

4.1 THE MODEL

By using the general manner that an electric utility is regulated, it is possible to model a residential consumer's typical bill to a general rate structure form. The general form equation is:

$$(4.1)\quad RB_t = B_o + B_1TOPER_t + B_2TCC_t + e_t$$

where:

RB_t = Residential consumer's typical monthly bill.

$TOPER_t$ = All O&M expenses including fuel, taxes, depreciation and amortization expenses, and gains/losses from disposition of electric utility plant.

TCC_t = Capital costs which include electric utility plant in service minus CWIP and depreciation times the ROR.

From this equation, it is possible to derive an equation that breaks out the cost components that will be directly affected by the Amendments. The following equation represents this breakout. High-sulfur and low-sulfur coal costs are removed from O&M costs and the cost of the scrubber, depreciated over time, is separated from the capital costs.

$$(4.2)\quad TBR_{it} = B_o + B_1HSC_{it} + B_2LSC_{it} + B_3OPER_{it} + B_4CC_{it} + B_5SCRUB_{it} + e_{it}$$

where:

TBR_{it} = Typical bill of a residential customer who consumes 750 kilowatt-hours per month for lighting, appliances, refrigeration, cooking and water heating

HSC_{it} = High-sulfur coal costs; coal with a sulfur content greater than 1.2 pounds per MMBtu

LSC_{it} = Low-sulfur coal costs; coal with a sulfur content less than 1.2 pounds per MMBtu

$OPER_{it}$ = Total operating expenses (O&M expenses, taxes, depreciation and amortization expenses, and gains/losses from the disposition of electric utility plant) less coal costs

CC_{it} = Capital costs (Electric utility plant in service minus CWIP and depreciation times the ROR) less the cost of $SCRUB_{it}$

$SCRUB_{it}$ = Capital cost of a scrubber less depreciation (assume straight line depreciation over 30 years) times the ROR.

There are other variables, such as embedded costs for each customer class (residential, commercial and industrial) that are difficult to obtain and are not readily available publicly. Embedded cost of service is what it costs to serve a particular class and a utility's revenue needs are apportioned among the various customer classes based on the division of embedded costs. Also, the philosophy and political direction of the state commission over time is another important variable that has not been included in the model. State commissions do not follow a strict embedded cost and prudent expense agenda. The commissions are often swayed by exogenous political and economic considerations. The data for the variables listed in equation (4.2) are from public sources. Table 3 lists each variable and the source that it was taken from.

Table 3. Model Components and Their Sources

Model Component	Source
TBR_{it}	Federal Power Commission [18], 1975-1977 and U.S. Department of Energy [12], 1978-1988
HSC_{it}	National Coal Association [35]
LSC_{it}	National Coal Association [35]
$OPER_{it}$	Federal Power Commission [17], 1975; U.S. Department of Energy [11], 1976-1981; and U.S. Department of Energy [10], 1982-1988
CC_{it} [1]	Federal Power Commission [17], 1975; U.S. Department of Energy [11], 1976-1981; and U.S. Department of Energy [10], 1982-1988
$SCRUB_{it}$	Federal Energy Regulatory Commission [16], 1975-1988

1 The ROR used to calculate the CC_{it} variable is the annual electric utility average from Regulatory Research Associates [40].

The utilities included in the database are investor-owned electric utilities that have at least one generating unit that is predominantly coal-fired. There are 90 investor-owned utilities in the database. All investor-owned utilities with coal-fired generation that sell power solely at wholesale are excluded. Five other investor-owned utilities with coal-fired generation are also excluded because of inconsistent data.

For the forecast period 1989 to 2002 assumptions were made for each of the independent variables. Forecasts of the variables are based on the assumption that there will not be a high level of inflation; oil shortages; sharp increases in the price of oil, coal or natural gas; and no large increase in demand that would require generating facilities to be built. Table 4 lists the actual capacity with installed scrubbers as of 1988. This table also gives the capacity with installed scrubbers that is used for the forecast of equation (4.2). Table 5 lists the specific assumptions used for the forecast period for each of the variables.

Table 4. Actual and Forecast Installed Scrubber Capacity

	Installed Scrubber Capacity (Megawatts)
Actual as of 1988	34,501
Forecast for 2000	58,981
Total Actual and Forecast	93,482

Source: National Coal Association, [35].

U.S. Department of Energy, [9].

Table 5. Assumptions for Equations A Through F, 1989-2002

Variable	Annual Increase 1989-1995	1996-1999	2000	2001-2002
	(1)	(2)	(3)	(4)
Typical Bill	5%	5%	8/15/25%	5%
High Sulfur	5%	5%	5%	5%
Low Sulfur	5%	9%[2]	9%	9%
Operating Costs[3]	5%	5%	5% (+1%)[4]	5% (+1%)[4]
Capital Costs[5]	2%	2%	2%	2%
Scrubber Costs	------Existing scrubbers as of 1988------ less depreciation[6]		Install scrubbers of $209/kW	Install scrubbers less depreciation[6]

Note: Assuming an annual inflation rate of 5 percent.

[1] Three forecasts to be tried; one 3 percent (plus 5 percent for inflation; another 10 percent (plus 5 percent for inflation); and 20 percent (plus 5 percent for inflation).

[2] Assume utilities start to negotiate long-term low-sulfur coal contracts in 1996. This causes low-sulfur coal costs to escalate at 4 percent per annum (plus 5 percent inflation).

[3] Total operating expenses less coal costs.

[4] Five percent plus an additional 1 percent for each scrubber installed to account for scrubber maintenance and disposal of sludge.

[5] Assumes minor additions and repairs to utility plant only.

[6] Assume a 30-year depreciation.

Given actual historical data there are a total of six equations that represent electric utilities' costs depending on whether they burn low-sulfur or high-sulfur coal and whether a utility has or has not constructed a scrubber at their coal-fired generating facilities. The following are the six equations:

(4.3) Equation A: $TBR_{it} = B_o + B_1HSC_{it} + B_2OPER_{it} + B_3CC_{it} + e_{it}$

(4.4) Equation B: $TBR_{it} = B_o + B_1HSC_{it} + B_2OPER_{it} + B_3CC_{it} + B_4\,SCRUB_{it} + e_{it}$

(4.5) Equation C: $TBR_{it} = B_o + B_1LSC_{it} + B_2OPER_{it} + B_3CC_{it} + e_{it}$

(4.6) Equation D: $TBR_{it} = B_o + B_1LSC_{it} + B_2OPER_{it} + B_3CC_{it} + B_4\,SCRUB_{it} + e_{it}$

(4.7) Equation E: $TBR_{it} = B_o + B_1HSC_{it} + B_2LSC_{it} + B_3OPER_{it} + B_4CC_{it} + e_{it}$

(4.8) Equation F: $TBR_{it} = B_o + B_1HSC_{it} + B_2LSC_{it} + B_3OPER_{it} + B_4CC_{it} + B_5SCRUB_{it} + e_{it}$

To test the validity of estimating six separate equations, Chow tests were run on all possible pair permutations. The overall result from these tests was that Equation C illustrated a strong structural difference and Equation D was also strongly structurally different, but less so. A Chow test was also run pairing up data from Equations A, B, D, E and F as one group and Equation C as a separate group. The Chow test statistic in this instance was 39.90. This result shows a strong structural difference since the F-statistic at the 0.05 level of significance with five restrictions and a sample of 1,260 is 2.21 and an alternative test statistic used when the sample size is large is 7.18. The Chow statistic is larger then both so the null hypothesis of no structural difference is rejected. Then a Chow test was run on the pairing up of data from Equations A, B, E and F as one group, Equation C as a second group and

Equation D as a third group. The resulting Chow test statistic of 48.84 showed an even stronger structural difference then for the previous pairing.

The three separate equations as they were run for the last Chow test are as follows:

(4.9) $TBR_{it} = B_o + B_1HSC_{it} + B_2LSC_{it} + B_3OPER_{it} + B_4CC_{it} + B_5SCRUB_{it} + e_{it}$

(4.10) $TBR_{it} = BC_o + B_1HSCC_{it} + B_2LSCC_{it} + B_3OPERC_{it} + B_4CCC_{it} + B_5SCRUBC_{it} + e_{it}$

(4.11) $TBR_{it} = BD_o + B_1HSCD_{it} + B_2LSCD_{it} + B_3OPERD_{it} + B_4CCD_{it} + B_5SCRUBD_{it} + e_{it}$

These three equations are then combined into a single equation as follows:

(4.12) $TBR_{it} = B_o + B_1HSC_{it} + B_2HSCC_{it} + B_3HSCD_{it} + B_4LSC_{it} + B_5LSCC_{it} + B_6LSCD_{it} + B_7OPER_{it} + B_8OPERC_{it} + B_9OPERD_{it} + B_{10}CC_{it} + B_{11}CCC_{it} + B_{12}CCD_{it} + B_{13}SCRUB_{it} + B_{14}SCRUBC_{it} + B_{15}SCRUBD_{it} + B_{16}DUMC_{it} + B_{17}DUMD_{it} + e_{it}$

where DUMC is a dummy variable representing the constant term (BC_o) from equation (4.10) and DUMD is a dummy variable representing the constant term (BD_o) from equation (4.11).

The next step is to determine which variables make these three groups structurally different from one another. The following null hypothesis (4.13) is tested using an F-test (4.14). The F-test is used to determine if the coefficients of similar variables (i.e., HSC_{it}, $HSCC_{it}$ and $HSCD_{it}$) are the same:

$$(4.13) \qquad Ho: \ B_i = B_j = B_m$$

where i = 0,1,4,7,10,13; j = 2,5,8,11,14,16; and m = 3,6,9,12,15,17.

$$(4.14) \qquad \frac{(SSE_R - SSE_U)/r}{SSE_U/(n - k)} \sim F_{r,n-k}$$

where SSE_R is the error sum of squares when the null hypothesis is imposed; SSE_U is the unrestricted error sum of squares, r is the number of restrictions imposed by the null hypothesis and k is the number of regressors. To calculate (4.14) regressions were run.

The mainframe statistical package TSP, version 4.0 was used to run all regressions. An ordinary least squares (OLS) regression was run for the unrestricted equation. The null hypothesis [(4.13)] was tested for each group of similar variables including the intercept terms ($B_o = B_{16} = B_{17}$) using the F-statistic as defined in (4.14). The null hypothesis was accepted only in the case of HSC_{it} (i.e. the null hypothesis that $B_1 = B_2 = B_3$) and $SCRUB_{it}$ ($B_{13} = B_{14} = B_{15}$).

There are some possible explanations as to why equations (4.10) and (4.11) are structurally different and in particular why specific variables contribute to this structural difference. The first is that the utilities in these two equations burn only low-sulfur coal. Another is that the utilities in (4.10) are primarily located in the south/southeast region of the United States and utilities classified in (4.11) are located primarily in the west/southwest, whereas the remaining utilities are located in general in the Mid-Atlantic, Appalachia and Midwest regions. The difference in the O&M and capital costs are likely to be a result of generation mix. Utilities that have a higher ratio of oil-fired generation to other generation will have relatively higher O&M costs then a utility with a lower ratio of oil-fired to other generation.

Utilities with nuclear exposure, especially in the 1980s have a different capital structure than those utilities that own a limited share or no nuclear plants at all. Several utilities in equations (4.10) and (4.11) have had a significant nuclear exposure during the 1980s. However, a difference between these two groups is that the utilities classified in (4.10) have had a difficult time recovering nuclear generation plant expenses. Many of the utilities are in financial straights and their rates may reflect these financial difficulties rather than actual costs.

The three variables from a similar grouping were then combined into a single variable in the cases where the null hypothesis [(4.13)] was accepted and left as three separate variables whenever the null hypothesis [(4.13)] was rejected. The new equation is as follows:

$$(4.14) \quad TBR_{it} = B_o + B_1HSC_{it} + B_2LSC_{it} + B_3LSCC_{it} + B_4LSCD_{it} + B_5OPER_{it} + B_6OPERC_{it} + B_7OPERD_{it} + B_8CC_{it} + B_9CCC_{it} + B_{10}CCD_{it} + B_{11}SCRUB_{it} + B_{12}DUMC_{it} + B_{13}DUMD_{it} + e_{it}$$

The data used to estimate this equation is pooled data. This means that the data is both time series and cross sectional. Pooled data has special problems -- both serial correlation and heteroskedasticity are likely to be present. Serial correlation occurs when error terms from different time periods are correlated. This problem usually occurs in time series but may occur across cross sectional observations as well. The other problem, heteroskedasticity, usually occurs when examining cross sectional data. In the case of electric utilities, large utilities have a greater variation in their costs since they serve a larger service territory with a more diverse customer load then a smaller utility.

Table 6 presents the results of the OLS, heteroskedasticity corrected and serial correlation corrected regressions. The theory of electric utility rate structure indicates that the coefficients for each variable should be positive and significant.

4.1.1 OLS Results

For the OLS regression the HSC_{it}, LSC_{it}, CCC_{it}, CCD_{it} and DUMD all have negative coefficients. The remaining variables have positive coefficients. The variables HSC_{it}, $OPER_{it}$ and CCD_{it} are not significant at the 0.05 level of significance, and the remaining variables are significant at the 0.05 level of significance.

The standard errors in general can be considered large given the values of the coefficients. Although there is no absolute level to judge the standard errors by, it is hoped that the standard error is at most 10 to 15 percent of the coefficient (the 10 to 15 percent criteria). The variables that meet this criteria are $LSCD_{it}$ (16.60 percent, slightly higher than the 15 percent boundary) and CCD_{it} (13.24 percent). The standard errors as a percent of the coefficient for the remaining variables ranges from 19.83 to 128.54 percent.

The adjusted R-squared (R^2) for this equation is low at 0.1769 which at first glance does not indicate a strong explanatory relationship between the independent variables and the dependent variable. However, R^2 may not be the best measure of "goodness of fit" for either time series or cross-sectional data. Time series data often produces a higher R^2 because the variables growing over time are likely to do a good job of explaining the variation of any other variables that are also growing over time. On the other hand, cross-sectional data may produce a low R^2 even if the model is satisfactory because of the large variation across individual units of data.

Table 6. Summary of Regression Results

Independent Variables	OLS	Correction For: Heterosked-asticity	Serial Correlation
	(1)	(2)	(3)
HSC_{it}			
1. Coefficient	-0.3785E-08	-0.3785E-08	0.2141E-07
2. Standard Error	0.4865E-08	0.3696E-08	0.4105E-08
3. *t*-statistic	-0.7780	-1.0239	5.2151
LSC_{it}			
1. Coefficient	-0.1129E-07	-0.1129E-07	0.1848E-07
2. Standard Error	0.4616E-08	0.3744E-08	0.3964E-08
3. *t*-statistic	-2.4453	-3.0144	4.6634
$LSCC_{it}$			
1. Coefficient	0.5452E-07	0.5452E-07	0.6094E-07
2. Standard Error	0.2139E-07	0.2274E-07	0.1859E-07
3. *t*-statistic	2.5487	2.3976	3.2772
$LSCD_{it}$			
1. Coefficient	0.1391E-06	0.1391E-06	0.8501E-07
2. Standard Error	0.2310E-07	0.1727E-07	0.2152E-07
3. *t*-statistic	6.0230	8.0575	3.9498
$OPER_{it}$			
1. Coefficient	0.5503E-08	0.5503E-08	0.1662E-07
2. Standard Error	0.1916E-08	0.1727E-08	0.1544E-08
3. *t*-statistic	2.8723	3.1861	10.7639
$OPERC_{it}$			
1. Coefficient	0.3085E-07	0.3085E-07	0.3888E-07
2. Standard Error	0.9629E-08	0.1228E-07	0.6368E-08
3. *t*-statistic	3.2033	2.5128	6.1057
$OPERD_{it}$			
1. Coefficient	0.2274E-08	0.2274E-08	0.7976E-08
2. Standard Error	0.3772E-08	0.1989E-08	0.2733E-08
3. *t*-statistic	0.6028	1.1432	2.9180

Table 6 (continued). Summary of Regression Results

		Correction For:	
Independent Variables	OLS	Heterosked-asticity	Serial Correlation
	(1)	(2)	(3)
CC_{it}			
1. Coefficient	0.1730E-07	0.1730E-07	0.5504E-08
2. Standard Error	0.6794E-08	0.6319E-08	0.3158E-08
3. *t*-statistic	2.5465	2.7380	1.7427
CCC_{it}			
1. Coefficient	-0.8283E-07	-0.8283E-07	0.2284E-07
2. Standard Error	0.2578E-07	0.4054E-07	0.1354E-07
3. *t*-statistic	-3.2124	-2.0433	1.6863
CCD_{it}			
1. Coefficient	-0.1272E-08	-0.1272E-08	-0.5016E-09
2. Standard Error	0.1685E-07	0.8342E-08	0.7410E-08
3. *t*-statistic	-0.7550E-01	-0.1525	-0.6770E-01
$SCRUB_{it}$			
1. Coefficient	0.3534E-06	0.3534E-06	0.1012E-06
2. Standard Error	0.7008E-07	0.5710E-07	0.5354E-07
3. *t*-statistic	5.0428	6.1889	1.8897
$DUMC_{it}$			
1. Coefficient	6.5665	6.5665	-1.1789
2. Standard Error	2.6694	3.0391	6.3920
3. *t*-statistic	2.4599	2.1607	-0.1844
$DUMD_{it}$			
1. Coefficient	-7.3358	-7.3358	-0.8644E-01
2. Standard Error	2.1222	1.8330	5.8298
3. *t*-statistic	-3.4566	-4.0020	-0.1483
Constant			
1. Coefficient	36.8135	36.8135	28.7155
2. Standard Error	0.6238	0.5979	1.8589
3. *t*-statistic	59.0155	61.5687	15.4476

Table 6 (continued). Summary of Regression Results

		Correction For:	
Other Statistics	OLS	Heterosked-asticity	Serial Correlation
	(1)	(2)	(3)
Number of Observations	1,260	1,260	1,260
R-Squared	0.1854	0.1854	0.5843E-01
Adjusted R-Squared	0.1769	0.1769	0.4861E-01
Standard Error of Estimate	13.8755	13.8755	4.4400
F-Statistic	21.8140	21.8140	-14.3882
Error Sum of Squares	239891	239891	24563.7
Durbin Watson Statistic	0.1152	0.1152	1.7071

The F-statistic computed in the OLS can be used to test the linear relationship between the independent variables and the dependent variable. The null hypothesis is:

(4.16) H_o: $B_1 = B_2 = B_3 = \ldots = B_i = 0$ where $i = 4,5,6 \ldots, 13$.

The F-statistic generated by TSP to test the null hypothesis [(4.16)] is 21.8140. The F-statistic at the 0.05 level of significance for k-1 = 14 and n-2 = 1,258 is approximately 1.67; where k is the number of independent variables in the equation and n is the number of observations. Since the calculated F-statistic is greater than 1.67, the null hypothesis is rejected.

The Breucsh-Pagan test performed from these results indicates the presence of heteroskedasticity and the Durbin Watson statistic of 0.1152 indicates that serial correlation is also present. TSP uses formulas suggested by White to correct for heteroskedasticity. This method is preprogrammed as a single word command (Robustse) and can only be used when running OLS regressions. This command causes the standard errors, the t-statistics and the variances of the coefficients to be consistent even when heteroskedasticity is present. This equation was also corrected for serial correlation with the Cochrane Orcutt procedure. A command used in the mode for correcting for serial correlation instructs the program to drop the first observation from each sample grouping (each grouping is data for an individual utility) so that the rho values are not calculated across cross-sectional units. Corrections for both heteroskedasticity and serial correlation were run for the unrestricted equation and all the restricted equations.

4.1.2 Heteroskedasticity Corrected Results

The coefficients, R-squared values and F-statistic are the same as for the OLS results. The standard errors and the t-statistics for the coefficients are different, however. The coefficients for the LSC_{it}, $LSCC_{it}$, $LSCD_{it}$, $OPER_{it}$, $OPERC_{it}$, CC_{it}, CCC_{it}, $SCRUB_{it}$, and DUMD are significant at the 0.05 level. The remaining variables are not significant at the 0.05 level.

The variables that meet the 10 to 15 percent criteria $LSCD_{it}$ (12.41 percent), CCD_{it} (13.24 percent) and $SCRUB_{it}$ (16.16 percent, slightly higher than the 15 percent boundary). The standard errors as a percent of the coefficient for the remaining variables ranges from 24.99 percent to 97.67 percent. Correcting for heteroskedasticity had a positive affect on the ratio of the standard error to the coefficient. This ratio decreased for all variables except $LSCC_{it}$, $OPERC_{it}$, CCC_{it} and DUMC. These coefficients correspond to equation (4.10). The utilities classified in this category as mentioned earlier, are having financial difficulties and their rates may not reflect their actual costs.

4.1.3 Serial Correlation Corrected Results

After correcting for serial correlation, all of the coefficients are positive except for CCD_{it} and the two dummy variables. The coefficients of the three capital cost variables, the variable representing scrubber costs and the two dummy variables are not significant at the 0.05 level and the remaining coefficients are significant at the 0.05 level. The variables that meet the 10 to 15 percent criteria are $OPER_{it}$ (9.29 percent), $OPERC_{it}$ (16.38 percent, slightly higher than the 15 percent boundary) and CCD_{it} (14.95 percent). The standard error as a percent of the coefficient for the dummy variables increased dramatically from the OLS regression from 40.65 percent to 542.24 percent for DUMC and from 28.93 percent to 6,744.26 percent for DUMD. This ratio also increased as well for CC_{it}, CCC_{it} and $LSCD_{it}$ although the increases were far less dramatic. The ratios for the variables not listed above range from 19.17 percent to 34.27 percent.

The adjusted R-squared has fallen to 0.0486. However a decrease is expected when correcting for serial correlation. The adjusted R-squared in this case is extremely low and could cause some concern how well the independent variables explain the dependent variable. The F-statistic calculated by TSP is negative -- which is an impossibility. After checking the data and the program carefully it is assumed that there is a glitch in TSP's calculation of the F-statistic when correcting for serial correlation

4.2 FORECAST OF RESIDENTIAL ELECTRIC BILLS

A regression is run for the equations corrected for heteroskedasticity and serial correlation and then a forecast command is issued. The forecast command uses the regression results combined with pre-estimated data for the exogenous variables to produce a forecast of the dependent variable. Table 7 and Figure 8 illustrate the forecasts for the years 2000 to 2002.

Table 7. Comparison of Forecasts for the Years 2000 Through 2002

Forecast Type	Forecast Years		
	2000	2001	2002
	--------(Dollars)--------		
	(1)	(2)	(3)
TSP Generated Corrected for:			
1. Heteroskedasticity	\$54.79	\$55.33	\$55.95
2. Serial Correlation	98.45	101.93	109.89
Other Forecasts:			
1. 3 Percent	100.90	100.90	100.90
2. 10 Percent	108.97	116.03	121.83
3. 20 Percent	114.42	126.12	132.43

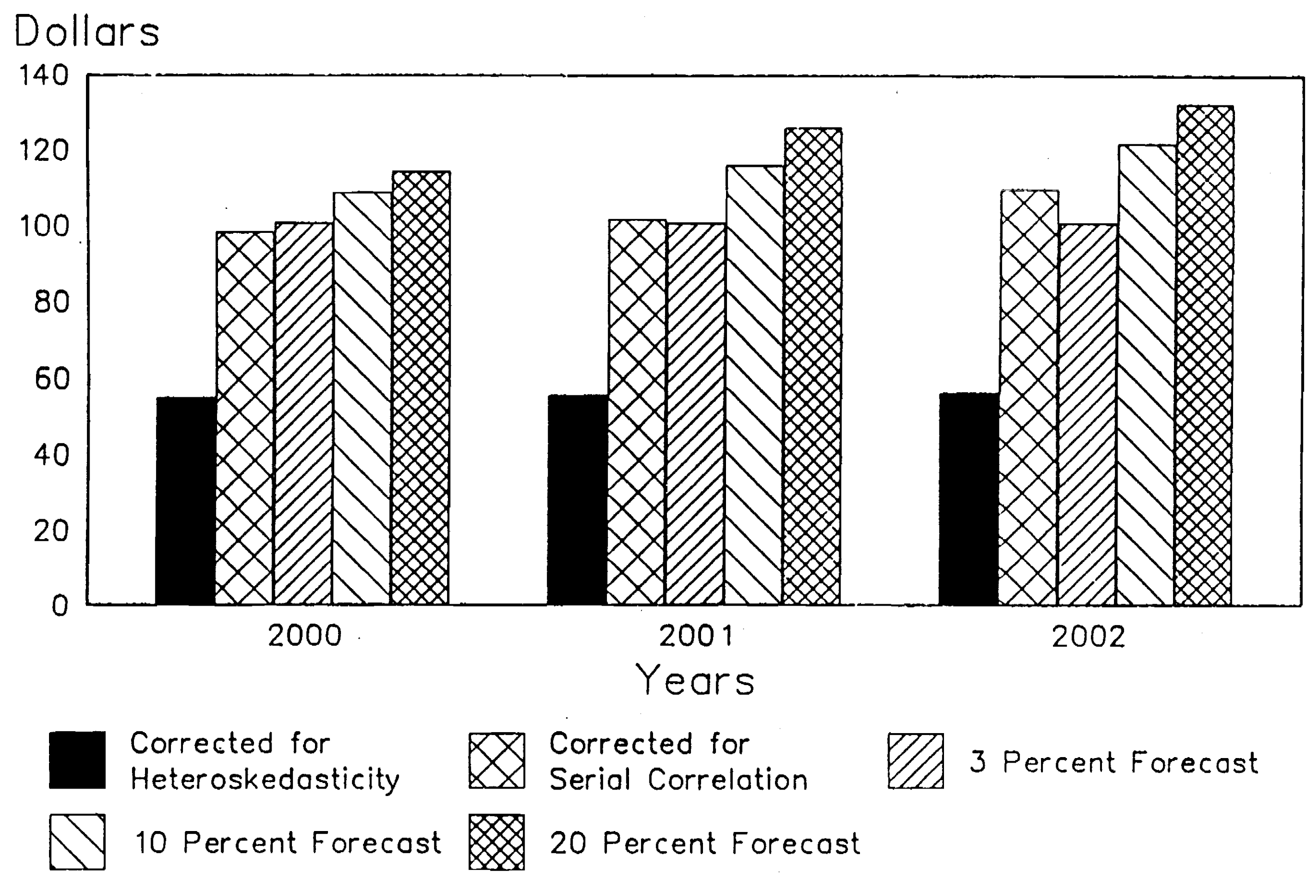

Figure 7. Comparison of Forecasts for the Years 2000 Through 2002

Each of the forecasts displayed in Table 7 and Figure 8 whether generated by TSP or estimated using the assumptions contained in Table 4, are the simple average of the individual utility's residential bills. Total compliance by all utilities takes place on January 1, 2000. The historical bills are based on residential rates as of January 1 of the given year and because of this fact the effect of compliance will not probably not be fully reflected in the customer's bill for the year 2000. The increase in rates for compliance of the Amendments will not be fully felt by the residential consumers until the year 2001.

In the case of the heteroskedasticity corrected forecasts, the bills generated by TSP for the years 2000 through 2002 are far below even the 3 percent level. However for the serial correlation corrected forecasts the values for the year 2000 is $2.45 less than the 3 percent forecast. For the year 2001, the forecast is $1.03 more than the 3 percent forecast and $14.10 less than the 10 percent forecast. And for 2002 the forecast falls between the 3 percent and 10 percent forecasts; greater than the 3 percent forecast by $8.99 and less than the 10 percent forecast by $11.94.

For the two TSP forecasts the standard deviation was calculated for each of the forecast years represented in Table 7. For the heteroskedasticity corrected model the standard deviations for the years 2000, 2001 and 2002 are 17.2955, 18.2432 and 19.3576 respectively. The standard deviation is approximately 32 percent of the forecast mean and this is quite high.

For the serial correlation corrected forecasts the standard deviations are 18.6955, 19.1020 and 20.7088 for the years 2000, 2001 and 2002 respectively. The standard deviation is approximately 19 percent of the forecast mean and although lower then for the heteroskedasticity corrected forecast it is still large. These large standard deviations do not make the forecasts accurate. The mean, plus or minus one standard deviation in the serial correlation case could drop the bill either far below the 3 percent forecast or raise it to the point between the 10 percent and 20 percent forecasts.

4.4 CONCLUSION

Compliance with the 1990 Clean Air Amendments will certainly increase utilities' costs and these costs will be passed on to the consumer. The degree of the cost increase to the utility and the rate increase to the residential consumer is unknown. Some utilities will incur larger cost increases then others because of historical generation choices and the selection of the method of compliance to reduce SO_2.

The forecasts generated by TSP are based on historical data and estimated data for the exogenous variables. The estimated values for the exogenous variables are based on conservative increases in the utility's cost components. The annual increases for the independent variables assume no shock to the economy that would result in high inflation rates and there is also the assumption that no major generating units will be constructed during this time period. The cost of a scrubber is based on estimates made by utilities and these may also be different depending on the rate of inflation and labor costs. The models also assume that the regulatory nature of the electric generating industry will not change significantly by the year 2002.

The forecasts after correcting for heteroskedasticity are significantly lower then the estimates made using the assumptions noted in Table 5. The serial correlation corrected forecasts are in the range as those estimated using the assumptions in Table 5. However, in both these cases the standard deviation is extremely large, making the forecasts inaccurate. For a 95 percent confidence band, the TSP forecasts are approximately plus or minus 40 dollars. The relationship between a utility's costs may not be linear. Transformation of the variables may lead to more accurate forecasts. Another aspect of further study could include other variables such as a measure of the financial health of the utility and the embedded costs attributable to residential customers for each utility. These additional variables may also make the forecasts more accurate.

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