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AIR POLLUTION, NUCLEAR POWER AND ELECTRICITY DEMAND

AN ECONOMIC PERSPECTIVE

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Introduction

The American electric utility industry has shown that it is capable of operating successfully in the turbulent economics of the past 10 years. Yet new problems are visible on the horizon, and considerable interest has focused on the industry's ability to continue to operate successfully in the future.

If these problems become severe, a transformation of the ownership, management, and regulation of the industry becomes possible. There are two obvious pathways to possible severe crisis: (1) physical insufficiencies in generating capacity with associated blackouts and brownouts, and (2) financial difficulties so serious that industry reorganization is an alternative to bankruptcy.

Formerly, these two pathways had opposite characteristics, the first being associated with exponential demand growth and the second with a demand shortage. However, two of the industry's current problems can theoretically cause both types of crisis to occur simultaneously.

Nuclear power, if prohibited by regulation from operation, can reduce available capacity. Simultaneously, substitute fossil fuel could be considerably more expensive, raising rates and reducing customer purchases. And, if the shutdown nuclear plants were excluded from rate base cost recovery, the affected utilities might approach bankruptcy via the inability to meet debt requirements. In a few words: (1) insufficient physical capacity, (2) rising rates and falling sales, and (3) avoided debt repayment.

Air pollution policies now being considered have some of the same characteristics. The Environmental Protection Agency analyzes sulfur oxide air pollution emissions from electric utilities and 27 other actual and potential categories as shown in Table 1. Electric utilities have two-thirds of all estimated emissions, six times the level of all industrial combustion, and ten times the level of copper processing. Consequently, air pollution control policies would have qualitatively the same effect on utilities as nuclear control policies. This would be possible if utilities were to face the problem of retrofitting all existing coal and petroleum plants for 90% sulfur removal, or closing those plants.

Of particular interest is the interaction of these problems: a major reduction in allowable sulfur emissions in a period of nuclear plant closure, perhaps spiced by another ratchet in oil prices.

Table 1. Leading Sources of Sulfur Oxide Emissions, 1981, in teragrams*

Source Category	Actual 1981
Electric utilities	14.8
All industrial stationary fuel combustion	2.3
Primary copper	1.4
Petroleum refining	0.8
Cement	0.6
Commercial fuel combustion, stationary	0.5
Iron and steel	0.4
Sulfuric acid	0.2
Residential	0.2
Natural gas production	0.2
All 18 other categories	1.1
Total	22.5

*A teragram equals 1.1 million American tons. Source: U.S. EPA, Emissions Estimates.

For this paper, we study these questions in the context of a detailed empirical model for New York State, its utilities and customers, and its power plants.

In addition to the separable and joint analyses of air pollution and nuclear policies, we examine national tax policy, general inflation, and oil prices.

1. The Significance of Demand

Ten years ago, electric utilities in the U.S. had experienced over two decades of steady growth at rates that were about double those for the economy as a whole. After the oil embargo in 1973, circumstances changed. The demand for electricity dropped in 1974, increased slowly until 1981, and declined again in 1982.

The slow growth of demand for electricity after 1973 is often attributed to the lack of economic growth. The average growth rate of the economy from 1975 to 1980 was, however, similar to the rates experienced in the fifties and sixties. Nevertheless, the demand for electricity grew at rates that were less than half those experienced before the oil embargo. A major reason for this changing situation is that the real cost of producing electricity increased substantially after 1973, whereas it had decreased during the fifties and sixties. In fact, the average price paid for electricity is now similar, in real terms, to the prices paid in the early sixties. These basic results are summarized in Table 2 in terms of the indices for electricity generation, national economic output and the average price paid for electricity. In all three cases, the index is computed with 1973 as the base year.

Table 2. Indices for Electricity Generation, Economic Output, and the Price of Electricity in the U.S.

Year	Generation	Real Gross National Product	Real Price of Electricity
1950	18	43	180
1960	41	59	136
1970	83	87	98
1973	100	100	100
1980	124	118	130
1982	121*	118	na

Source: The indices are derived from information in the Edison Electric Yearbook (generation and average nominal price) and the Economic Report of the President (real gross national product and the consumer price index, used to deflate average prices).

*Based on a preliminary figure obtained from the U.S. Department of Energy.

The change in the behavior of demand in the mid-seventies took utility planners by surprise. When demand was lower than expected, the poor performance of the economy and the disruptions of the oil embargo were cited as major causes. While these were contributing factors, the importance of increasing costs for electricity production was not widely recognized. As a result, projections of future demand made by utilities implied that substantial growth would occur in the future. This is illustrated in Figure 1, which shows actual levels of generation in New York State from 1965 to 1982 together with two forecasts that were made in the mid-seventies. The first representing an aggregation of forecasts made by individual utilities in the New York Power Pool, and the other is a forecast made using an econometric model with price effects included.[1] The aggregate forecasts across all states derived from the same econometric model also proved to be more accurate than the forecasts published by the National Electric Reliability Councils.[2] This is illustrated in Figure 2. Although these econometric forecasts were considered unrealistically low at the time of publication by utility planners, their accuracy has now been established. Since that time, many studies have confirmed that price effects matter (see Bohi for a recent survey), and this fact is increasingly recognized throughout the utility industry.

One important consequence of the unrealistically high forecasts made by utilities during the seventies is that new generating capacity was built to meet demand that has not materialized. In addition, the costs of construction have increased substantially, particularly for nuclear plants. In fact, these two factors have resulted in the termination of work on some nuclear plants before they were completed (e.g. three plants in the Washington Public Power Supply System), and in lengthy hearings to consider terminating work on others (e.g. Nine Mile Point 2 in New York State).

The combined effect of expensive new generating capacity, higher oil prices, and stable or declining demand causes average costs to increase. The magnitude of these problems varies throughout the nation. This is illustrated in Table 3, which shows the average annual growth rates for generation and installed capacity for nine census regions over different periods of time. During the fifties and sixties, generation and capacity grew at similar rates within each region, although rates varied across regions. From 1970 to 1973, the growth of capacity was greater than the growth of generation in all but the Mountain States. From 1973 to 1980, even though the growth rates of

FIGURE 1. GENERATION LEVELS IN NEW YORK STATE: FORECASTS AND ACTUAL EXPERIENCE

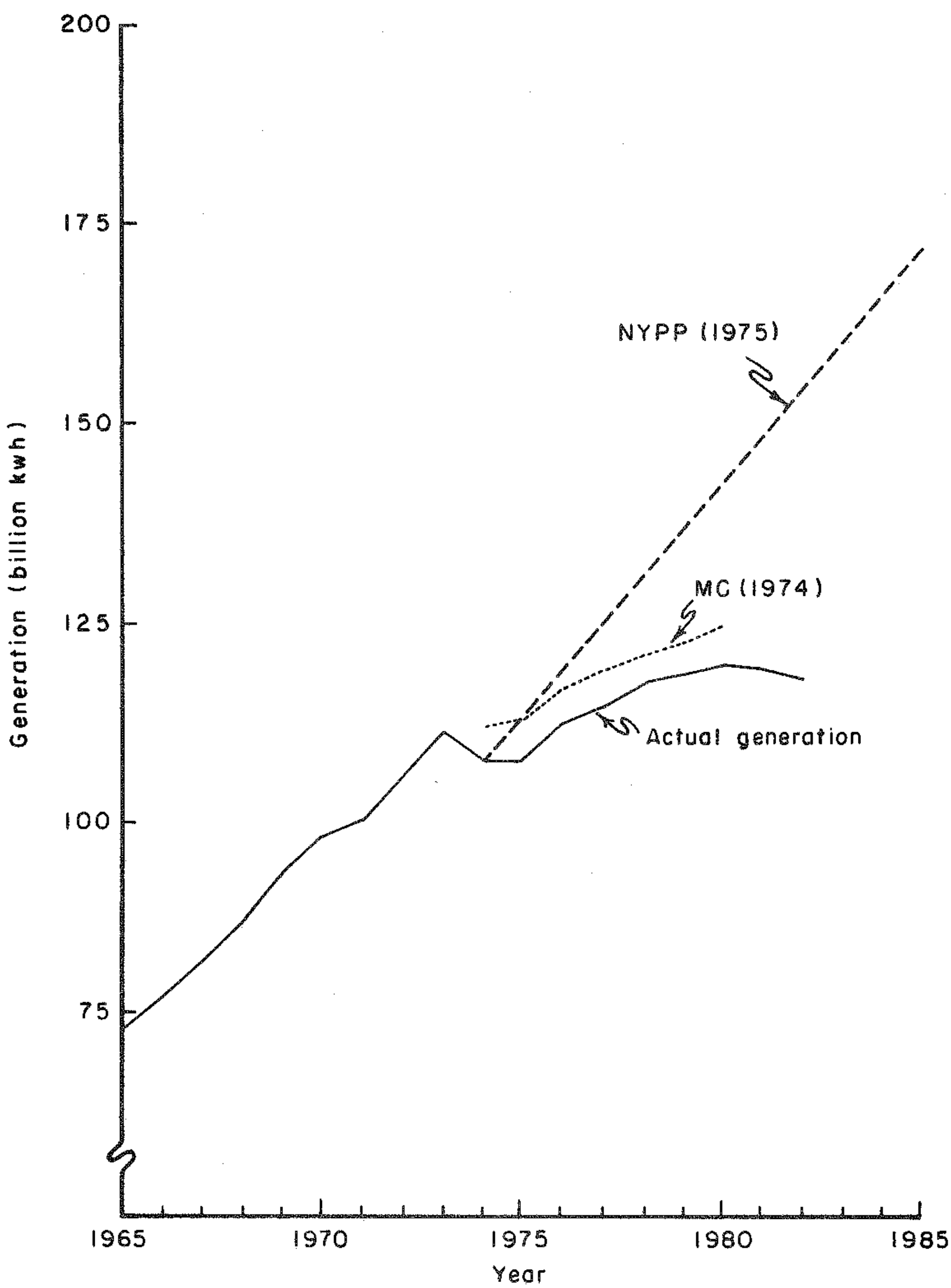


FIGURE 2.
TOTAL U.S. ELECTRICITY GENERATION, ACTUAL & FORECASTS

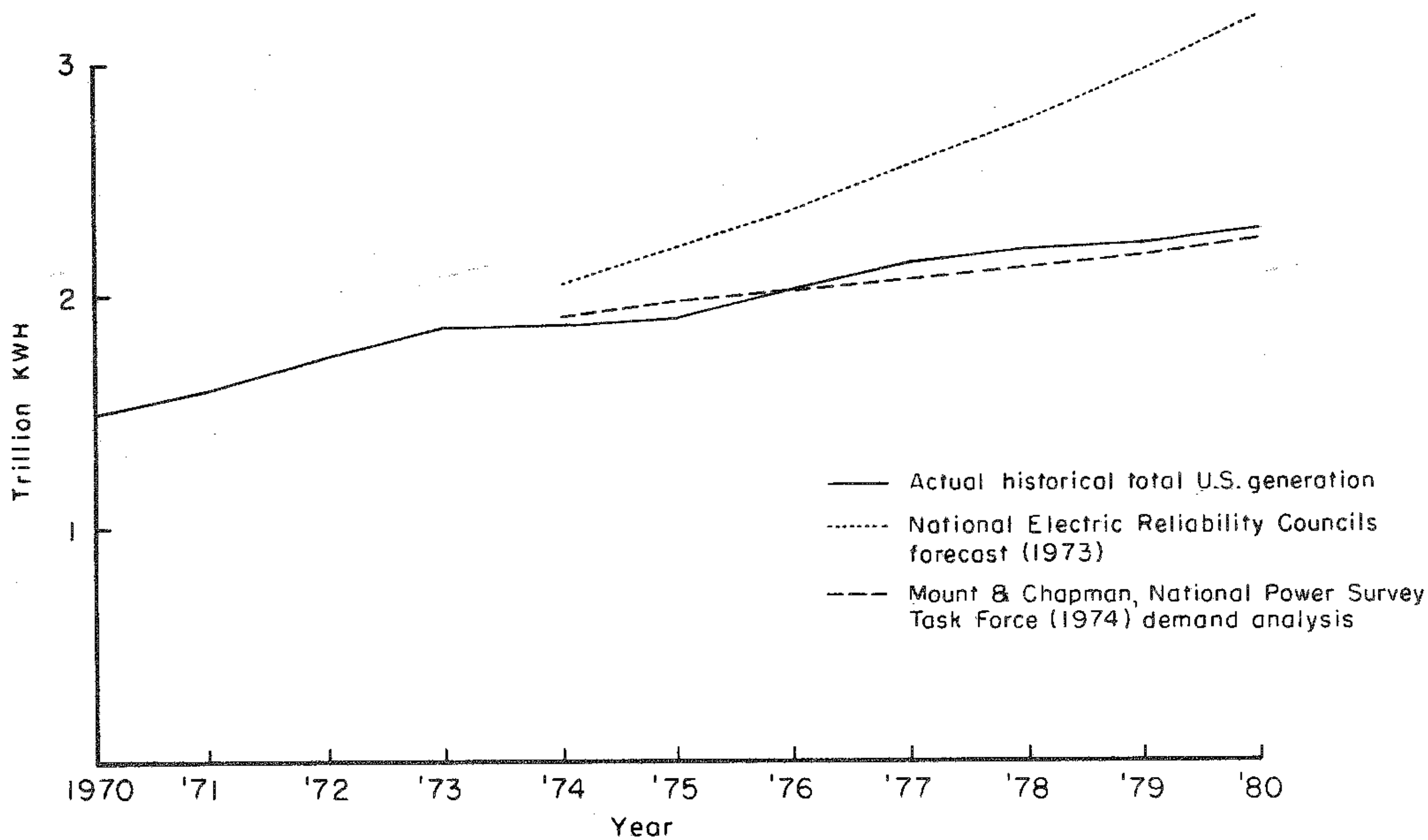


Table 3. Average Annual Growth Rates in Percent for Generation and Installed Capacity

	1950-1960		1960-1970		1970-1973		1973-1980		1980-1982
	Gen.	Cap.	Gen.	Cap.	Gen.	Cap.	Gen.	Cap.	Generation
New England (ME, NH, VT, MA, RI, CT)	5.9	5.8	7.8	6.6	5.8	8.6	1.2	3.1	-0.8
Middle Atlantic (NY, NJ, PA)	5.9	6.8	6.6	7.0	4.9	6.6	0.9	3.7	-1.6
East North Central (OH, IN, IL, MI, WI)	8.2	8.7	5.8	5.6	6.0	8.9	2.0	4.1	-3.6
West North Central (MN, IA, MO, ND, SD, NE, KS)	8.5	8.7	8.5	7.6	5.9	10.4	5.4	6.3	-0.3
South Atlantic (DE, MD, DC, VA, WV, NC, SC, GA, FL)	9.0	9.9	9.1	9.0	10.3	13.1	3.4	5.3	-1.5
East South Central (KY, TN, AL, MS)	13.6	14.0	5.3	6.3	7.1	8.0	2.6	4.7	-1.1
West South Central (AR, LA, OK, TX)	11.1	13.2	10.5	9.7	7.4	9.6	5.4	6.7	0.5
Mountain (MT, ID, WY, CO, NM, AZ, UT, NV)	8.3	9.8	7.0	6.8	10.1	8.8	7.4	7.5	3.3
Pacific (WA, OR, CA)	8.7	9.8	7.3	7.4	2.3	4.8	1.7	3.8	1.2
Total: 48 States	8.6	9.4	7.3	7.3	6.5	8.8	3.1	4.9	-1.0

Source: Derived from the Edison Electric Institute Yearbook, and from preliminary figures from the U.S. Department of Energy for generation levels in 1982.

capacity were substantially lower than in the previous periods, generation again grew more slowly than capacity in all regions.

The size of the difference between the growth rates of capacity and of generation from 1973 to 1980 gives an indication of the financial pressure on utilities. For a study of control policies for sulfur and nitrous oxide emissions, it is important to recognize that some regions which are major sources of these emissions have experienced reductions in sales since 1980. Much of the opposition by utilities to stricter controls on emissions is based on financial arguments (i.e. the cost is too high) rather than on the poor performance of the equipment itself. Hence, it is essential to understand how investment costs are translated into higher rates for customers, and what effect these higher rates have on demand, revenues, and the financial integrity of the utilities. These issues are analyzed by our EPA-sponsored model in the comparison of a number of alternative scenarios for the utilities, customers, and power plants in the New York Power Pool.

2. The URGE-AUSM and CCMU Models

The URGE-AUSM acronym represents Universities Research Group on Energy - Advanced Utility Simulation Model. The Group consists of engineers and economists from the University of Illinois, Carnegie-Mellon University, and Cornell University. It is sponsored by the U.S. Environmental Protection Agency. The objective of the Group is the development of a national economic and engineering model of air pollution emissions and utilities which can be used in studying national policies for acid precipitation mitigation.[3]

AUSM represents Advanced Utility Simulation Model. As the name implies, the logic of the model originated from Teknekron's Utility Simulation Model. Individual models within AUSM differ from their USM counterparts as shown in simplified form in Table 4.

The major characteristic of the AUSM which distinguishes it from USM is the closed loop or annually recursive nature of the model. Year t's generation level depends upon customers' response to prices in years t-1, t-2, etc. As section 1 indicated, the twin problems of price response and sales decline create new economic environments for utilities in the acid rain study region. AUSM portrays the response of electricity customers to variations in real prices in an ongoing, annually interactive system.

The earlier Baughman-Joskow-Kamat Regionalized Electricity Model was also dynamic in the same sense.[4] AUSM differs from Baughman et al in the depth of real data. Baughman et al was structured with census regions as the basic blocks. AUSM uses all actual plants in a state, and all financial data for all utilities in a state. It is being developed in a context in which AUSM can be applied to all states, their real plants, and their actual financial data.

At Cornell, we use a simplified AUSM which omits coal supply, generalized future planning, and the AUSM "gets/puts" structure. We term this version CCMU, for Cornell/Carnegie-Mellon Universities. It is used here to study New York. The individual architects of the submodels are listed in note 5. The CCMU model is shown in Figure 3. Note that the level of required generation in 1984 (year t+1) will be dependent upon customer demand which responds to costs and rates in 1983 (year t). This time structure is applied to all years in an analysis.

Table 4. AUSM Advancement from USM: Individual Models

1. Demand analysis: costs affect prices which affect levels of generation in an annually recursive framework. USM sales were exogenously defined.

2. Pollution control: much greater detail in sulfur removal; AUSM also analyzes NO_X.

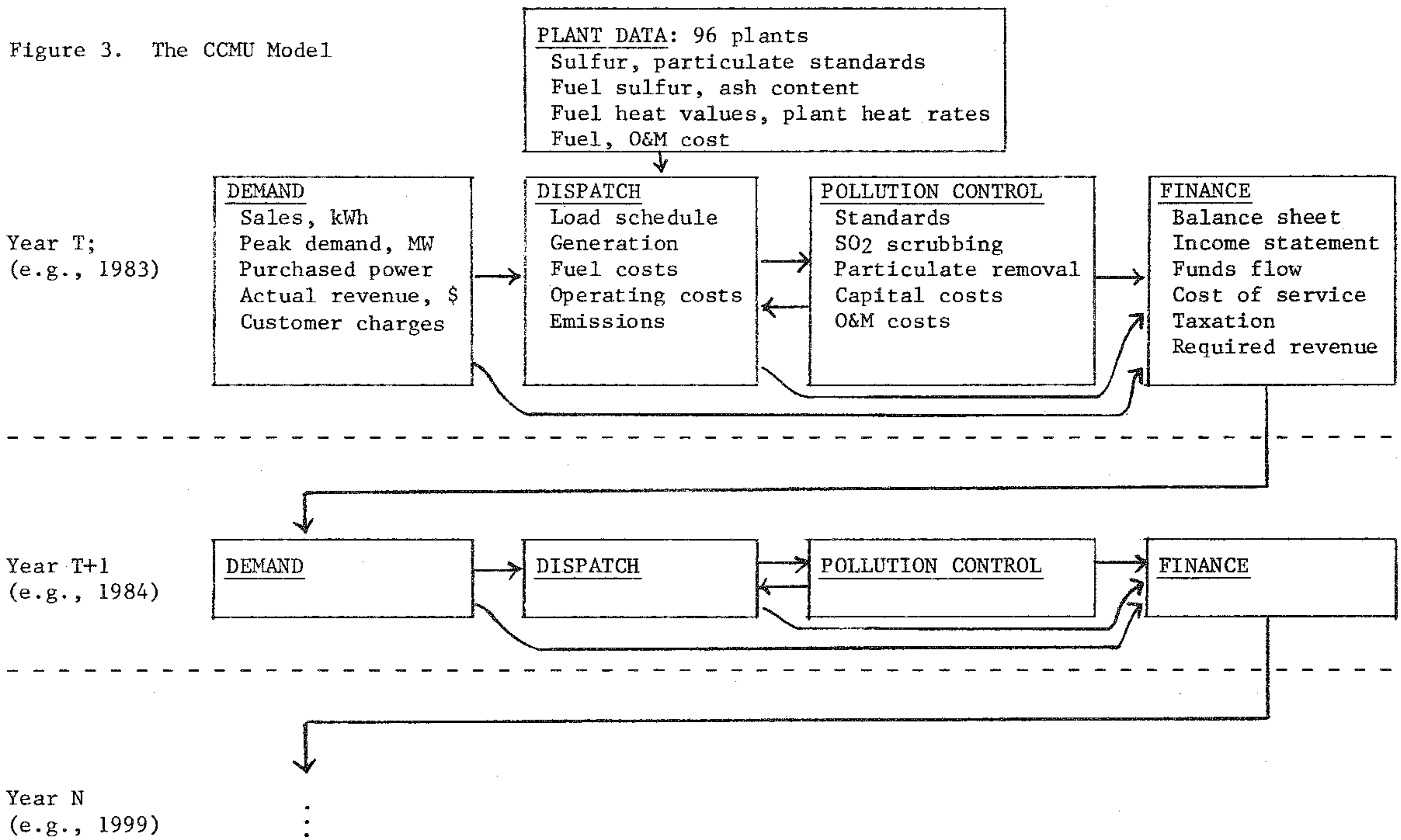
3. Dispatching: regional emissions constraints for least-cost dispatching, and minimum emissions dispatching with cost constraints. USM used least-cost dispatching only.

4. Utility finance: conventional balance sheets and income statements; detailed tax analysis and cost of service determination. Comparable to USM, but more comprehensive and based upon accepted concepts.

5. Planning: new capacity is based upon endogenous, price responsive demand analysis.

6. AUSM model structure: annual recursiveness makes cost variations affect demand, affecting dispatching, pollution emissions, cost, and finance, on a continuing basis.

Figure 3. The CCMU Model



3. Base Case Assumptions

The basic exogenous data is summarized in Table 5. New York has seven major private utilities and the public New York Power Authority (NYPA). Together, they constitute almost all of the State's generation. Several small municipal utilities generate or sell small amounts of electricity. In addition to generation from sources owned by New York utilities, the NYPA intends to increase its purchase of Canadian hydropower from 5 billion kWh in 1980 to 16 billion kWh.

The dispatching problem for this analysis is reasonably represented by a constrained least cost dispatching solution for the State's 100 power plants. The CMU linear program determines minimum cost with availability, capacity utilization, and region air pollution constraints. The plants are listed in Appendix A. Figure 4 shows the model's base case simulation. Note the comparison of actual and estimated values for 1980-82: the model is satisfactory.

Table 5 summarizes the plants by fuel type. Included there are the three plants being completed: Somerset (coal, 625 MW, scheduled to begin operations in 1985), Shoreham (nuclear, 809 MW, 1984), and Nine Mile Point #2 (nuclear, 1080 MW, 1987).

For all plants, actual 1980 fuel and operating costs in Appendix A are inflated each year by the assumptions in Table 5. As an example, consider future assumed coal cost for the Milliken plant, #5 in Appendix A. It used coal costing $23.64 per ton in 1980. The heat value for the coal and the heat rate for the plant defined costs of $1.47 $\overline{\text{M}}$Btu and $13.83/MWh. These costs are escalated at 7.06% each year, the result of the multiplicative interaction of 6% general inflation and 1% real escalation in coal cost. Similar calculations are made each year for each of the other fuels and for operating and maintenance cost.

Interest rates are assumed to average 12% and returns to shareholders are 15% for common stock and 13.5% for preferred stock.

Existing coal plants must meet pollution emission standards in State Implementation Plans. This is generally 1.9 lb of sulfur per $\overline{\text{M}}$Btu in New York, or 3.8 lb $SO_2/\overline{\text{M}}$Btu. The Homer City Pennsylvania plant is jointly owned between a New York and Pennsylvania utility, and the New York share is treated as 944 MW of New York capacity which must meet a 4 lb $SO_2/\overline{\text{M}}$Btu standard.

Table 5. Economic, Air Pollution, and Plant Data, Base Case

1. Exogenous Economic Parameters

General inflation 6%

Multiplicative escalation for individual utility fuels:

- nuclear 1%
- coal 1%
- oil 3%
- natural gas 3%

Change in population, employment, real earnings, and income: 0%

2. Financial Data

Number of utilities: 7 private, and New York Power Authority

Total electric plant: $13.9 billion in 1980

Rate base: $9.9 billion in 1980
$15.2 billion in 1987 with the new plants
$8.3 billion in 1987 without the new nuclear plants

Returns to common and preferred equity: 15% and 13.5%

Debt interest: 12%

Revenue 1980: $6.6 billion

Income tax expense, income statement, 1980: $538 million

Income tax payment, 1980: $168 million

Long term debt, 1980: $7.7 billion.

3. Dispatching: New York Plants, after 1982

	Capacity with new plants, MW	Availability factor	Maximum capacity factor	Capacity factor in base case, max. used
coal	4,155	.900	77%	77%
residual oil	11,692	.900	77%	31%
natural gas	4,047	.900	77%	33%
hydro	4,021	.900	77%	77%
nuclear	5,483	.575	77%	57.5%
distillate oil	2,374	.900	77%	1%
all plants	31,772			42%

4. Sulfur Emission Standards

A. Coal Plants

1. Ten at 1.90 lb S/$\overline{M}$Btu
2. One at 2.80 lb S/$\overline{M}$Btu
3. One NYPP plant in Pennsylvania at 2 lb S/$\overline{M}$Btu
4. Somerset, new plant, 0.6 lb SO_2/$\overline{M}$Btu

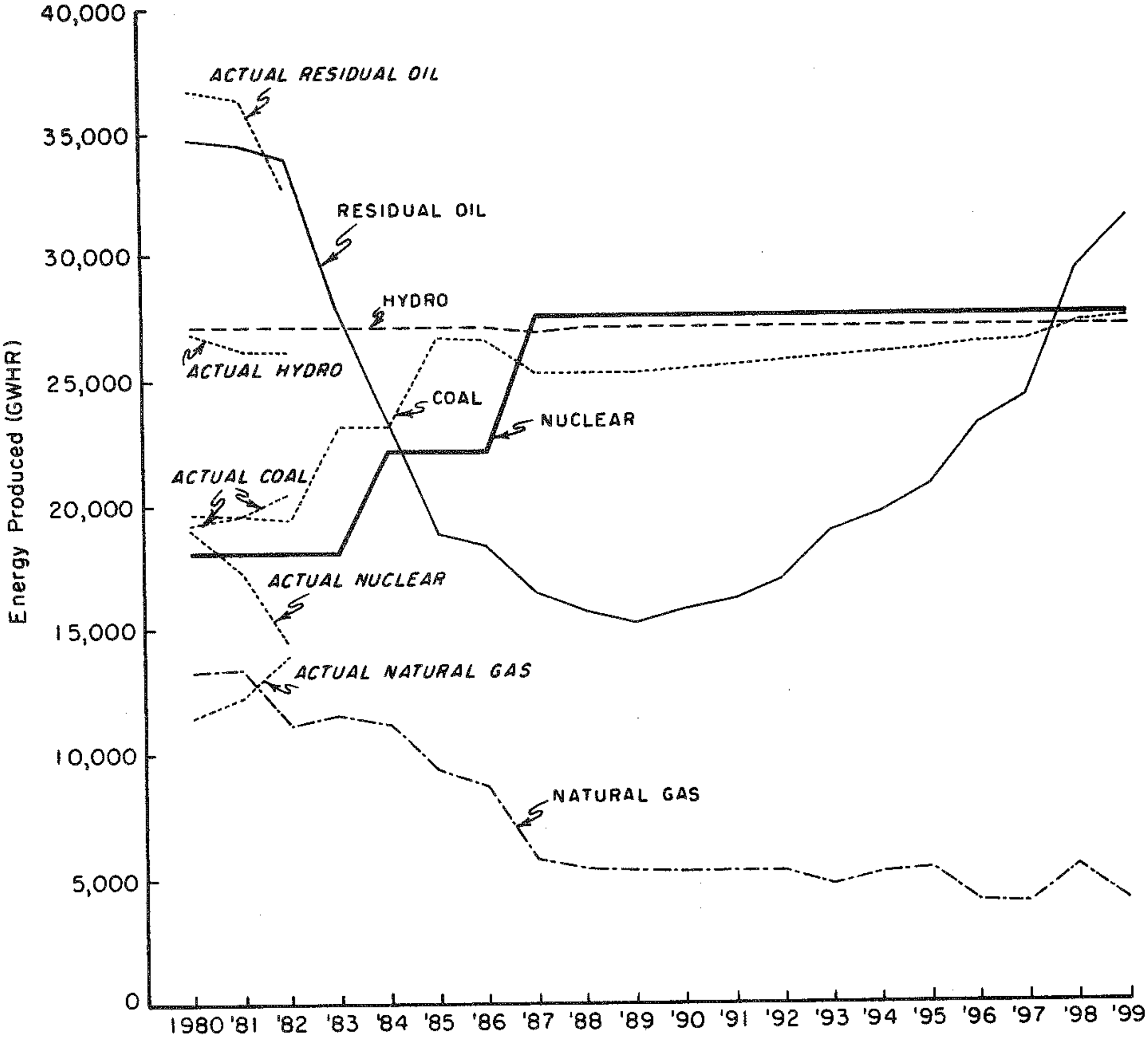
B. Oil Plants, all % S by weight

1. Eight at 0.30%
2. Two between 0.37% and 0.60%
3. Seven at 1.00% or 1.50%
4. Five at 2.00% or more

5. Nuclear Power Plants in New York

Indian Point 1	not operating
Indian Point 2	849 MW
Indian Point 3	855 MW
Nine Mile Point 1	610 MW
Nine Mile Point 2	1080 MW under construction, operate in 1987
Fitzpatrick	810 MW
Ginna	470 MW
Shoreham	809 MW under construction, operate in 1984.

FIGURE 4. GENERATION BY FUEL TYPE, BASE CASE MODEL: 1980-1999, ACTUAL: 1980-1982



One major new coal plant is being built, the 625 MW Somerset facility. It will be required to meet the 0.6 lb/MBtu SO_2 emission standard for new plants.

Metropolitan oil plants usually are required to use oil not exceeding 0.3% sulfur by weight. Upstate oil plants may use higher sulfur oil.

New York Power Pool members have eight nuclear plants. Five are now operating. Two, as noted, are scheduled to begin operations in the next four years. One, the original Indian Point #1 plant, is inoperable.

4. Regulatory Economics and Customer Cost

The time path of regulated prices is significantly divergent from the levelized cost of the plant and equipment. This means that a utility's financial health and the rates charged customers both have a significant time dimension, as is clear in Figure 5. That figure shows the regulated prices for a single nuclear plant; it is as if a single corporate entity was established solely to generate and sell the power from the plant.[6] Note that deflating the price curve results in a real price trajectory which declines over the planning period. Note also that the levelized price is a horizontal 15.6¢/kWh. The engineering concept of levelized cost does not reflect either the actual revenue received by a utility or the deflated real price which influences customers.

This is evident in the basic equations for regulatory pricing and levelized cost:

$$\text{(1)} \quad LC = K * FCR + OC$$

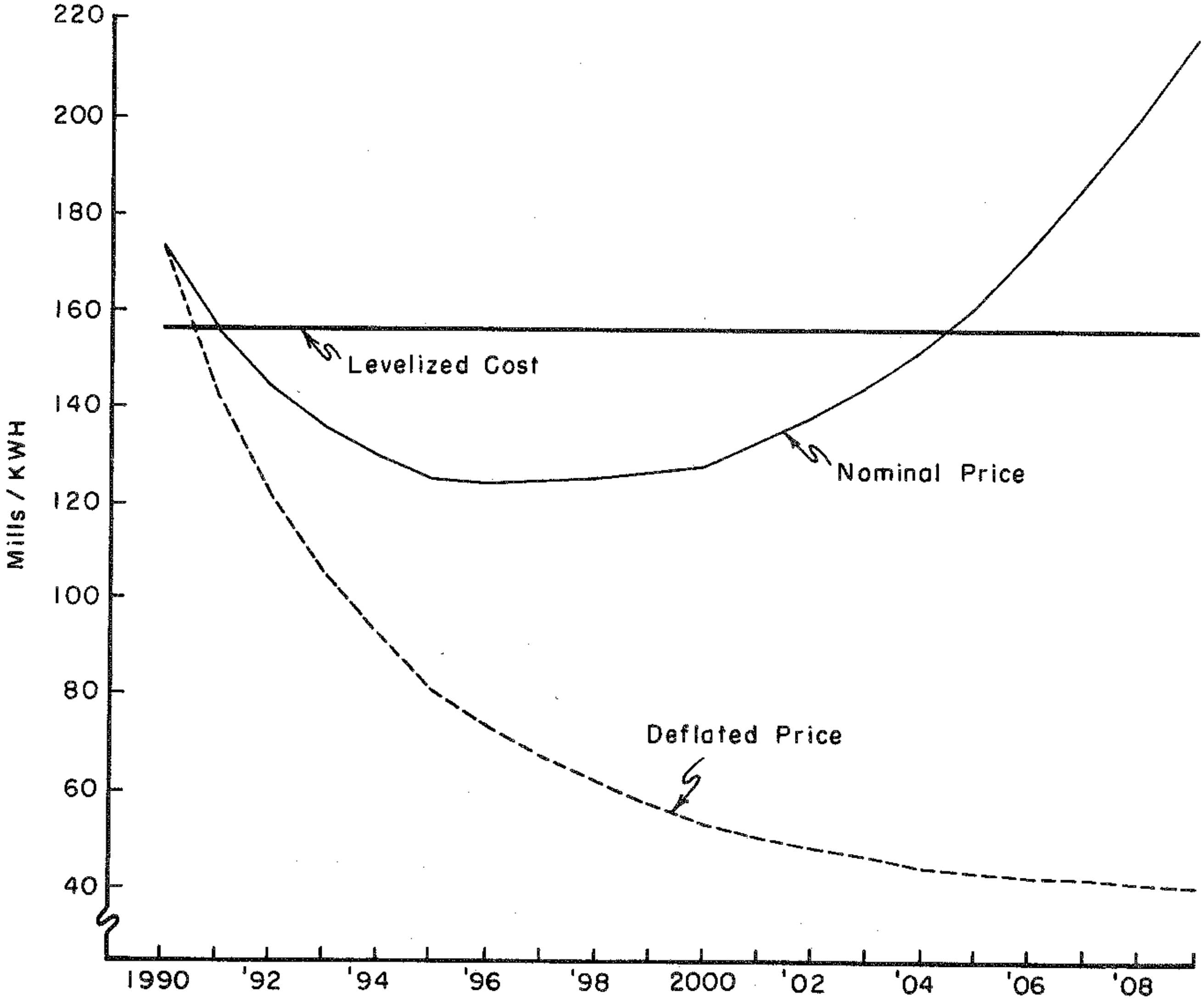
$$\text{(2a)} \quad P_t = \frac{REVCAP_t}{Q_t} + OC_t$$

$$\text{(2b)} \quad REVCAP_t = \frac{r}{1 - z} [K - CD_t - DTA_t - ADITC_t] + SD_t - \frac{z}{1 - z} INT_t$$

LC, OC, and P are expressed in mills/kWh, and represent levelized cost, operating cost including fuel and maintenance, and price. K is the investment cost including an allowance for interest during construction. FCR is the fixed charge rate in Eq. (1), and is based upon a capital recovery factor and investment-linked expenses such as property taxes and insurance. REVCAP defines revenue for capital recovery in the simplified regulatory equations and Q is generation. In Eq. (2b), r is rate of return, z is the corporate income tax rate, CD is accumulated normal straight line depreciation, DTA is deferred income tax arising from cumulative accelerated depreciation, ADITC is the cumulative investment tax credit to be deducted from rate base, and SD is current straight line depreciation.

As is evident, actual regulation defines a price which varies considerably from levelized cost. Note also that the real, deflated price is always declining. This is because of ongoing rate base erosion, a problem to be

FIGURE 5. LEVELIZED COST, REGULATED PRICE, AND DEFLATED PRICE



noted again below.

During the Growth Era from 1946 to 1973, deflated prices for electricity did decline regularly. Demand grew in response to this real price effect, and in response to the effects of income and population growth. This, of course, is a main point in section 1.

If this experience should be repeated and real electricity prices decline again, then renewed sales growth would be expected. Figure 6 shows that an inflation rate of 10% rather than 6% would make electricity price decline more rapidly. Figure 7 shows the response in higher sales. A higher general inflation--even though it is passed on to fuel costs--makes electricity a better buy.

Taxation, as indicated in the discussion of Eqs. (1) and (2), has a major influence on utility and customer costs. Figure 8 shows the effect of different tax policies on New York utilities. They can be represented with Equations (3)-(6).

(3) NI = REV + AFUDC - FC - OM - SD - TAX - DEFTAX - INT

(4) TI = REV - FC - OM - AD - INT

(5) TI = NI - AFUDC - (AD - SD) + TAX + DEFTAX

(6) TAX = z * TI - ITC

Net income (NI in Eq. (3)) has revenue (REV) and the allowance for funds used during construction for equity and debt (AFUDC) as positive components, and is reduced by fuel and purchased power cost (FC), operating and maintenance cost (OM), normal straight line depreciation (SD), actual corporate income tax paid (TAX), deferred and other non-current tax account items (DEFTAX), and actual interest expense (INT).

Note that AFUDC and DEFTAX are not actually current income terms. Taxable income (TI) in Eq. (4) eliminates both, uses accelerated depreciation AD rather than straight line depreciation SD, and is of course on a pre-tax basis.

Eq. (5) shows the relationship between net income and taxable income.

Although simplified, these equations give the basic corporate income tax structure. The base case in Figure 8 shows estimated Federal corporate

FIGURE 6. REAL PRICE, 1980 $, WITH 10% INFLATION

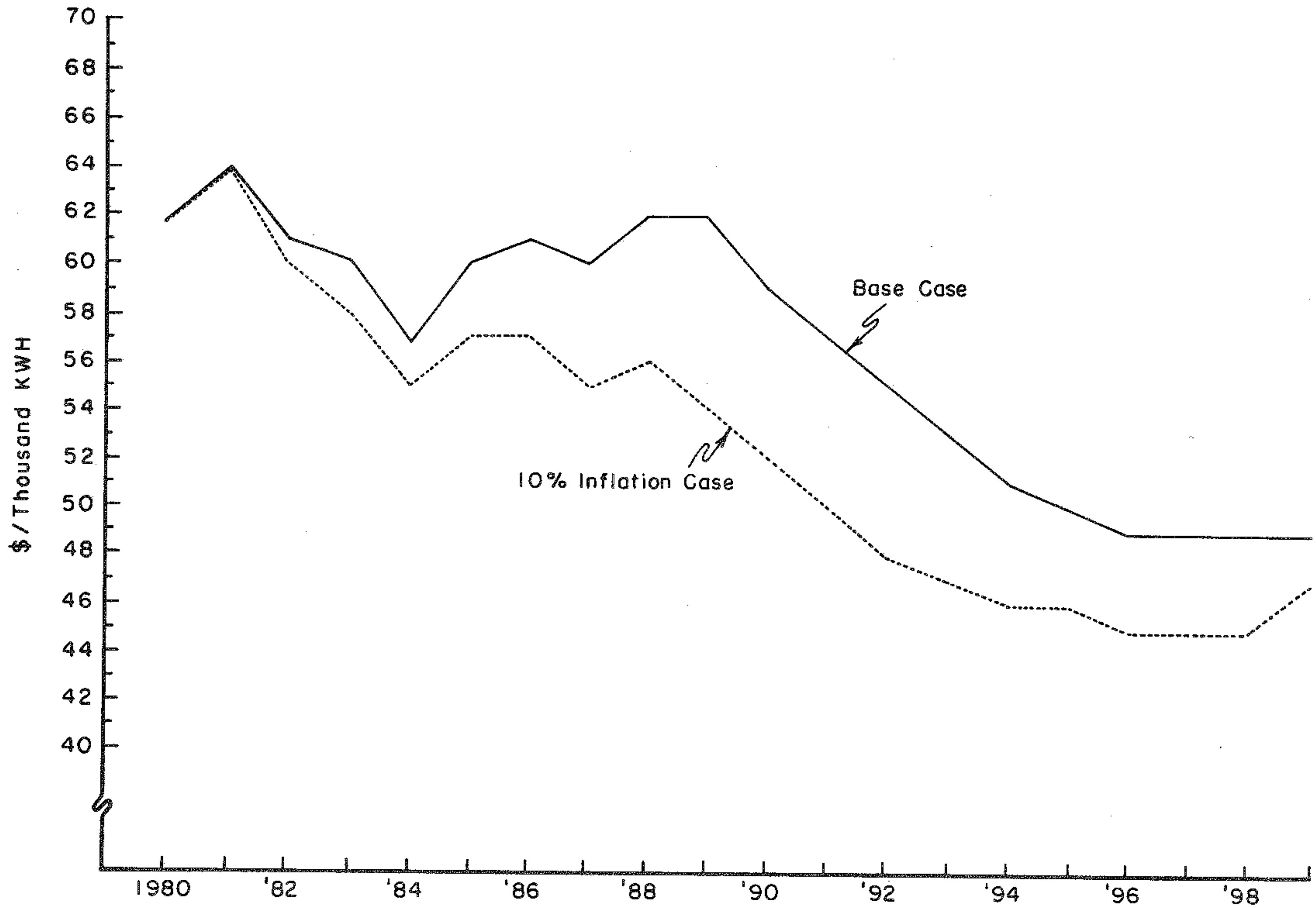


FIGURE 7. TOTAL SALES, BILLION KWH, WITH 10% INFLATION

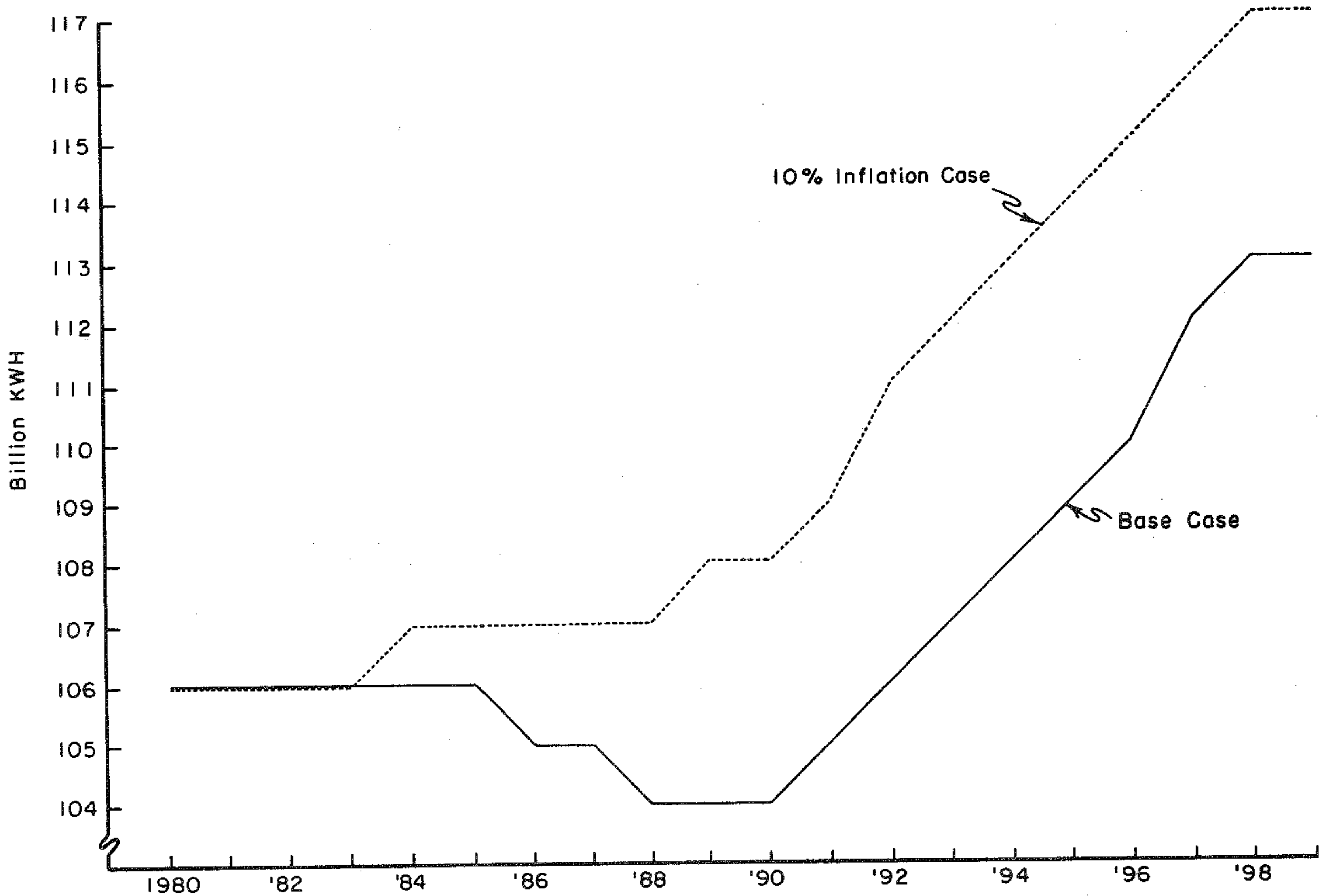
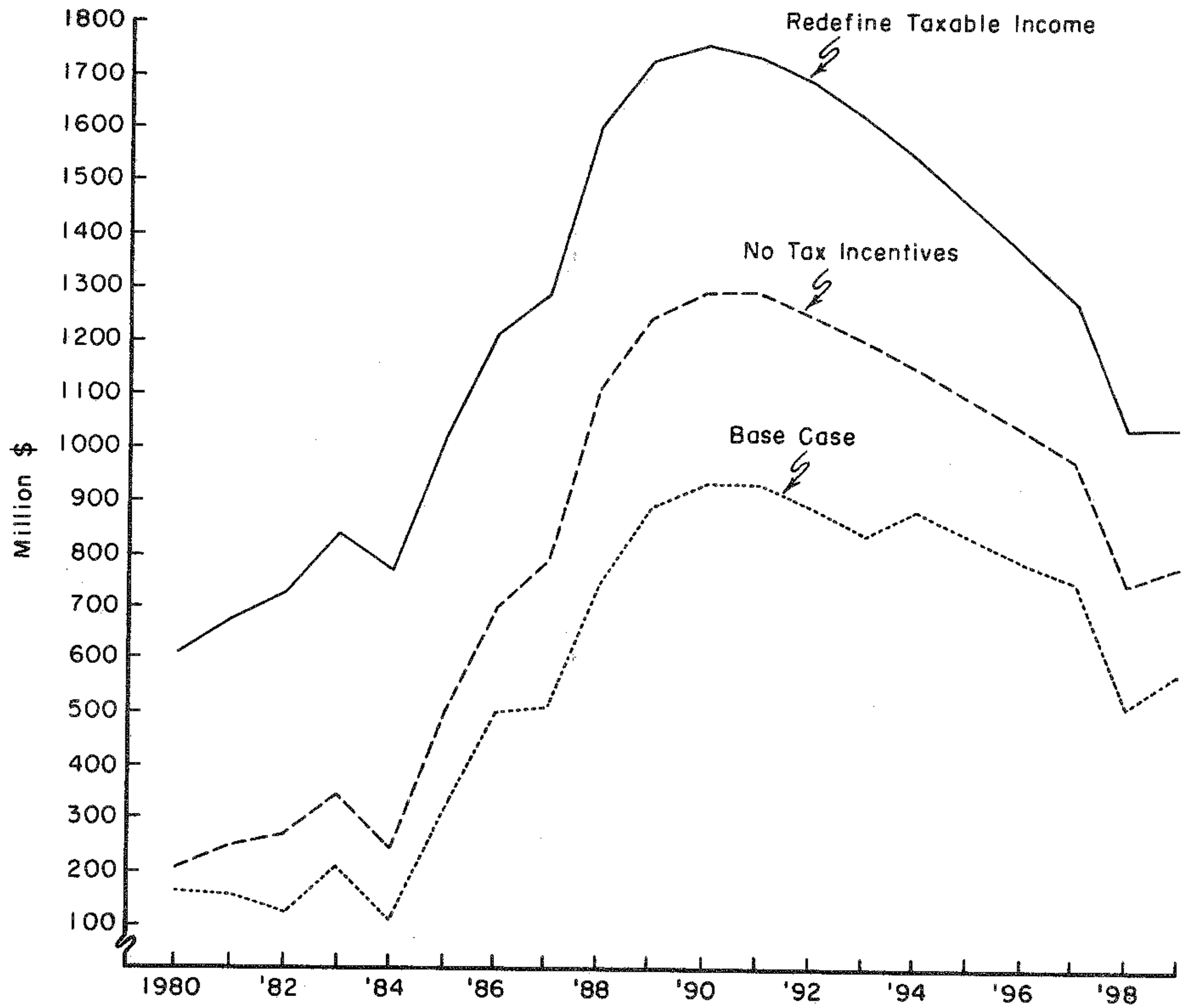


FIGURE 8. TAX POLICY AND FEDERAL INCOME TAX PAID, MILLION $



income tax, taken from Appendix B. Current Federal income tax payment in the base case is generally \$100-\$200 million in the early 1980s as investment tax credits from the three new plants are utilized. For the remainder of the period, actual tax payment is between \$500 million and \$1 billion.

Prior to the introduction of the investment tax credit and accelerated depreciation for tax accounting, book and tax accounts were more similar, as in Eqs. (7)-(9).

(7) $NI = REV + AFUDC - FC - OM - SD - TAX - INT$

(8) $TI = NI - AFUDC + TAX$

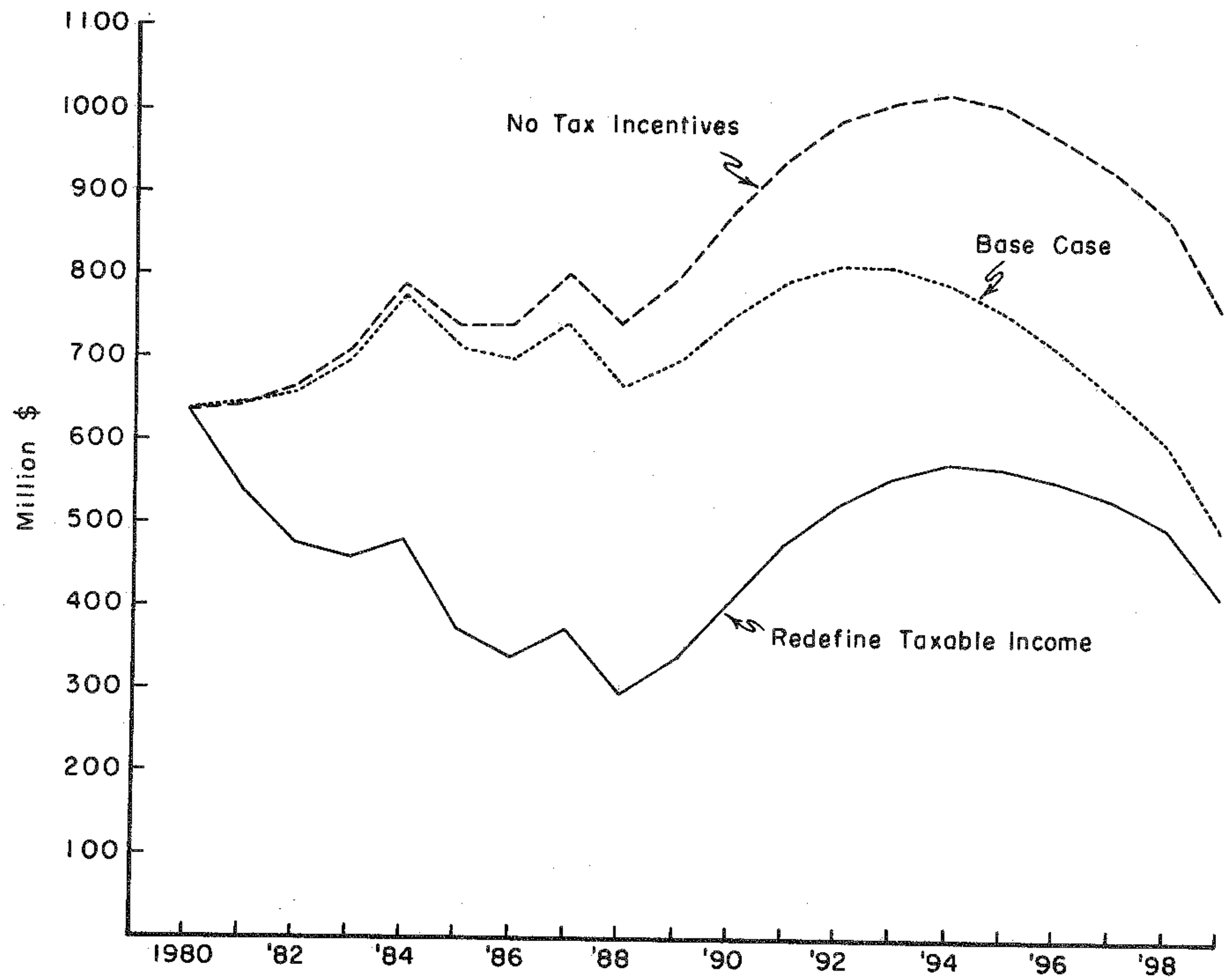
(9) $TAX = z \times TI$

Elimination of the investment tax credit and accelerated depreciation as in Eqs. (7)-(9) gives the middle "no tax incentives" case in Figure 8. Actual tax payment would exceed \$1 billion in nine of the years in the period.

One tax restructuring being considered is the replacement of the corporate income profit tax with a value added tax. Under this concept, net income before interest would be taxed at equal rates whether arising from shareholder or lender capital. Most value added proposals include wage income. However, for simplicity, we define taxable income as equal to Eq. (8), but with the addition of interest expense which is not deductible in value added taxation. In Figure 8, this is "redefine taxable income," and more than doubles base case payments. In 1990, \$1.8 billion for Federal taxation would be paid, and collected from customers if the tax rate remained at .46.

The following Figure 9 shows the effect of these tax assumptions on common dividends when these dividends are one-fourth of beginning-of-the-year retained earnings.

FIGURE 9. TAX POLICY AND COMMON DIVIDENDS, MILLION $



5. Estimating the Effect of Rates on Demand

Although the average cost of producing power can be determined by applying rules derived from regulatory practices, this cost is not necessarily charged to all customers. Different prices can be charged to different customers, and in 1981, for example, the average prices paid in the residential, commercial and industrial sectors in the U.S. were 5.89, 5.97 and 4.03 ¢/kWh, respectively.[7] In addition, the price charged to a class of customers depends on the level of use because typically rates have a block structure. The average changes in a residential bill paid in 1981 for an additional 250 kWh per month, for example, were $17.76, 14.85, 11.38 and 14.17 for the four 250 kWh increments from 0 to 1000 kWh.[8] The specific way in which a given cost increase is passed on to different classes of customers and its effect on the shape of the rate schedule for each class affects the levels of demand and revenue. Since the response of demand to a given cost increase is not unique, rates may be designed to encourage growth or to encourage conservation, and consequently, the overall design of rates has implications for emissions and air quality.

The demand model of the AUSM identifies three major sectors (residential, commercial and industrial) and two characteristics of the rate schedule for each sector. The first characteristic is the "marginal price", which represents the change in the bill paid if one additional kWh is purchased. Typically, this marginal price is lower than the average price paid because of the declining block structure of rates. The second characteristic is the "customer charge", which represents all charges that are made above (or below) the marginal price in other blocks.[9] The average revenue received from a customer in sector s each year can be represented as

$$(10)\quad R_s = CC_s + MP_s * Q_s$$

where R is the revenue in $, CC is the customer charge in $ per year, MP is the marginal price in $/kWh and Q is the quantity of electricity purchased in kWh/year.

The demand model operates in a recursive fashion, and it is assumed that the customer charge and marginal price are fixed for each class of customers at the beginning of every year. Most rates are designed to represent the average cost of service for each class of customers and for different levels of use within each class. This process is approximated in the model by dividing the average cost into a fuel and a non-fuel component.

Each year the fuel component is adjusted to account for changes in the cost of fuels, based on the pattern of generation in the previous year, and this increment affects the marginal prices paid in all sectors. When actual revenues received differ from "allowed" revenues, the non-fuel components, including the customer charges, are adjusted to represent the regulatory process of maintaining "allowed" rates of return on investment.

Let the average cost of service in year t be composed of fuel costs, FC_t, and non-fuel costs, NF_t, and the allowed increments to these components be ΔFC_{t+1} and ΔNF_{t+1}, respectively (all measured in \$/kWh). Then the new marginal prices and customer charges can be defined as follows for each sector s:[10]

$$(11)\quad MP_{s,t+1} = MP_{s,t} + \Delta FC_{t+1} + (MP_{s,t} - FC_t)\Delta NF_{t+1}/NF_t$$

$$(12)\quad CC_{s,t+1} = CC_{s,t}(1 + \Delta NF_{t+1}/NF_t)$$

In New York State, and in most other states, the importance of customer charges as a source of revenue declined substantially during the period 1970 to 1980. In 1970, over 20 percent of total revenue came from customer charges, but by 1980 this share had fallen to 13 percent. In addition, although the shares of sales to the three sectors are similar in 1970 and 1980, the relative importance of the residential sector as a source of revenue declined because rate differentials across sectors were reduced. This reflects the effects of higher fuel costs on rates. These results are summarized in Table 6.

An important feature of the demand model is that the marginal prices are used in the demand equations, and they influence sales. In contrast, the customer charges have little effect on sales. Hence, flattening or inverting rates tends to reduce demand. The marginal prices charged can differ substantially under the same cost situation, and revenue requirements can still be met by specifying customer charges appropriately. This characteristic is used to investigate the implications of incremental cost pricing in section 9 of the paper.

Table 6. The Composition of Sales and Revenues in New York State in 1970 and 1980 (Percent of Total Sales or Revenues)

		SECTOR		
	Residential	Commercial	Industrial	Total
Sales: 1970	30	38	32	100
1980	30	39	31	100
Revenues: 1970				
Sales * Marginal Price	23	40	16	
Customer Charges	16	4	1	
Total	39	44	17	100
Revenues: 1980				
Sales * Marginal Price	28	40	19	
Customer Charges	7	6	0	
Total	35	46	19	100

Economic conditions, the prices of competing fuels, and the two rate characteristics determine the quantity of electricity demanded in each sector. This is done through the use of sets of econometric equations; one set is applied to each sector. Each set of equations determines the demand for electricity and the demand for major primary fuels (natural gas, distillate oils, residual oils, gasoline and coal). (While the focus of this paper is limited to electricity, note that the model also estimates the uses of these other fuels by customer class.)

In an econometric model, there is a different equation for every variable predicted by the model, and predictions are derived for specified levels of the input variables. In this case, the models are based on a linear logit specification that predicts the shares of total expenditures allocated to electricity and to other fuels in each sector. This form ensures that predicted quantities are always positive and that the sum of predicted expenditures always adds to total expenditures.

The final step in specifying an econometric model is to estimate values for the unknown parameters by fitting the equations to a sample of observations of the variables. The sample for the demand model represents annual data for individual states for the years 1968 to 1979, and a more detailed account of the model's structure and of the estimation results are provided in another publication.[11] The main result of interest here is whether the estimated model provides an accurate explanation of the changes in the demand for electricity. The results are summarized in Table 7 for each fuel and sector in terms of the root mean squared error (typical error of prediction), and the R^2. Since an R^2 of one corresponds to a perfect fit, it is clear from Table 7 that the performance of the model is good, particularly for electricity. The R^2 is .98 or .99 for all three classes, and, at its highest, the typical error is only 8% of the mean value. It should be noted that the use of per capita figures avoids exaggerating the fit of the model by correcting for variability that is simply due to the size of the population in different states. The main conclusion is that the demand equations are able to "explain" the changing use of electricity during both periods of high growth (1968 to 1973) and of low growth (1973 to 1979). Although sales of electricity are declining now in many states, sales could grow again if there is both economic growth and declining prices for electricity, relative to inflation and to the prices of other fuels.

The basic economic characteristics of the estimated equations can be summarized in terms of "elasticities".[12] Two important qualifications need to be made, however, when interpreting these values. The first is that the response of demand to changing economic conditions is not instantaneous. The immediate response to price changes, for example, is inelastic and relatively small in the short-run. The elasticities summarized in Table 8 represent the long-run effects of changes when all adjustments have been completed, and describe the underlying characteristics of the model under the assumptions that only one variable is changed and all other input variables are held constant. The second qualification is that the elasticities are not really constants, but are characteristics of the model that can be evaluated for any given set of expenditure shares. If the share of expenditures going to electricity increases, the price responsiveness will also increase, implying that if electricity gets more expensive, in real terms, price becomes more important.

The three elasticities for the price of electricity are relatively inelastic, particularly in the residential sector. One reason for this is that the price used is the marginal and not the average price. Substitution

Table 7. Predictive Performance of the Estimated Equations for the Quantities of Electricity and of Primary Fuels Used per Capita (48 states for 1968 to 1979)

	SECTOR								
	Residential			Commercial			Industrial		
	Mean	RMS	R^2	Mean	RMS	R^2	Mean	RMS	R^2
1. Electricity	9.40	.36	.99	7.35	.33	.99	11.28	.93	.98
2. Natural gas	21.07	1.08	.99	10.81	.86	.98	37.04	5.96	.97
3. Distillate oils	19.57	2.64	.95	7.12	1.76	.91	12.21	3.83	.87
4. Residual oils		--		10.79	2.60	.83	22.77	4.87	.79
5. Gasoline	48.61	2.80	.92		--			--	
6. Coal		--			--		17.54	3.92	.98

Mean Average annual use ($\overline{\text{M}}$Btu/capita)
RMS Root mean squared error of prediction ($\overline{\text{M}}$Btu/capita)

$$RMS = \sqrt{\frac{1}{T}\sum_{t=1}^{T}(P_t - A_t)^2},$$ where P_t and A_t are the predicted and actual values for year t.

R^2 Measures the relative importance of the unexplained variability to the total variability of the actual series.

$$R^2 = 1 - \sum_{t=1}^{T}(P_t - A_t)^2 / \sum_{t=1}^{T}(A_t - \overline{A})^2$$

where $\overline{A}$ is the mean of $A_1, A_2, \ldots, A_T$.

Table 8. Estimated Long-Run Elasticities for Electricity Demand by Sector[a/]

Variable	SECTOR Residential	Commercial	Industrial
Price of Electricity	-.30	-.65	-.55
Price of Substitute Fuels	.15	.01	.52
Income per Capita	.07	--	--
Population	1.00	--	--
Employment	--	1.00	1.00

[a/] Evaluated for the average expenditure patterns in the sample period 1968-79.

elasticities for primary fuels are relatively large in the industrial and residential sectors, but not in the commercial sector.

The income elasticity in the residential sector is also small, but this is one example of an elasticity value that is smaller in the long-run than in the short-run. This means that, for example, a permanent reduction in a State's income first causes a relatively large reduction in sales. Then, as time passes at the new lower income level, sales rise but do not reach the level that existed prior to the drop in income. In many earlier studies, a form of equation is used that always makes income effects larger in the long-run, but this cannot be correct for expenditures on all commodities. The condition that expenditures sum to income would not be maintained. The implication of the complete system of demand equations is that if demand is income inelastic (elastic) in the short-run, it becomes more inelastic (elastic) in the long-run.

Since policies that determine the cost of controlling emissions will affect the prices charged for electricity, the price elasticities are the most important characteristics in Table 8. The dynamic behavior of price response in each sector can be illustrated by the following example. A 15 percent price increase from a base set of assumptions is implemented and maintained throughout a 15 year forecast period. The percentage decline in sales in each sector from the base case is shown in Table 9. The response in the residential sector is relatively fast but the overall effect is small.

Table 9. The Percentage Reduction of Sales from a Base Forecast in Response to a 15 Percent Increase of Price

Number of Years After the Price Increase	SECTOR Residential	Commercial	Industrial
1	-2.5	-1.5	-2.2
2	-3.3	-2.7	-3.6
3	-3.7	-3.7	-4.7
4	-3.8	-4.5	-5.4
5	-3.9	-5.2	-5.8
10	-3.6	-6.9	-6.3
15	-3.6	-7.3	-5.9

Although the response is small in the other two sectors, the overall effects are relatively large. It is the delay in the response of demand to price increases that tends to cause problems for utility planners.

The base case in this analysis implies that sales will decline slightly during the eighties and then increase slowly during the nineties. The initial decline in sales is due partly to the increased rate base associated with the two new nuclear power plants. The rate base declines in the nineties, because no new plants are added. Since the average cost of service declines, demand grows. The most recent forecast made by the New York Power Pool gives annual energy requirements of 131 and 151 billion kWh in 1990 and 1999, respectively.[13] The corresponding values in the base case are 117 and 127 billion kWh. Last year, energy requirements were 117 billion kWh, down from 119 billion kWh in 1980.

6. Nuclear Power Availability

First, we examined the question of Nine Mile Point #2 and Shoreham availability. Figure 10 shows four cases, and reports the average annual residential charge in 1980 dollars per customer. In the base case, the plants operate, and average customer cost is $395 in 1988. In the other 3 cases, the two plants do not operate. These three cases vary according to the proportion of plant cost allowed in the rate base.

If the cost of an inoperable plant is in the rate base then its full cost is recovered from customers. The extreme, for 1988, shows a $410 residential charge if the plants are in the rate base but not operating.

Of course, if the plants are excluded from the rate base, customer charge declines, and is, for example, $355 in 1988. Since Table 5 showed rate base including the two plants to be $15 billion, and rate base without them to be $8 billion, the variation in residential customer charge is less than might be anticipated. This is partly because of the tax cushion. Figure 11 shows how Federal tax paid declines as rate base coverage falls for the plants. In the extreme, excluding rate base coverage causes Federal taxes to be $800 million less.

However, the following Figure 12 shows interest coverage to be uncomfortably low for the State if rate base exclusion is implemented. As a rule of thumb, continued coverage below a ratio of 2:1 for operating income to interest expense probably means severe problems with bond ratings and refinancing of existing debt.

Of course, the impact on the principal utility owners and their customers is much more severe than the State averages reported here. It implies that full rate base coverage spread over all the State's utilities and customers is necessary to manage a possible withdrawal of these nuclear plants from the State's capacity.

In Figures 13-15, all the State's nuclear plants have been required to cease operation in 1984, and all remain in the rate base. The State's fuel costs are $1.5 billion higher in 1990. Revenue increases similarly. The last of the three figures shows sales declining to 97 billion kWh in 1990 because of the higher prices to customers.

Air pollution emissions are much higher without nuclear generation. In

FIGURE 10. RESIDENTIAL CHARGE: NINE MILE 2 AND SHOREHAM DON'T OPERATE, RATE BASE ALLOWANCE VARIES

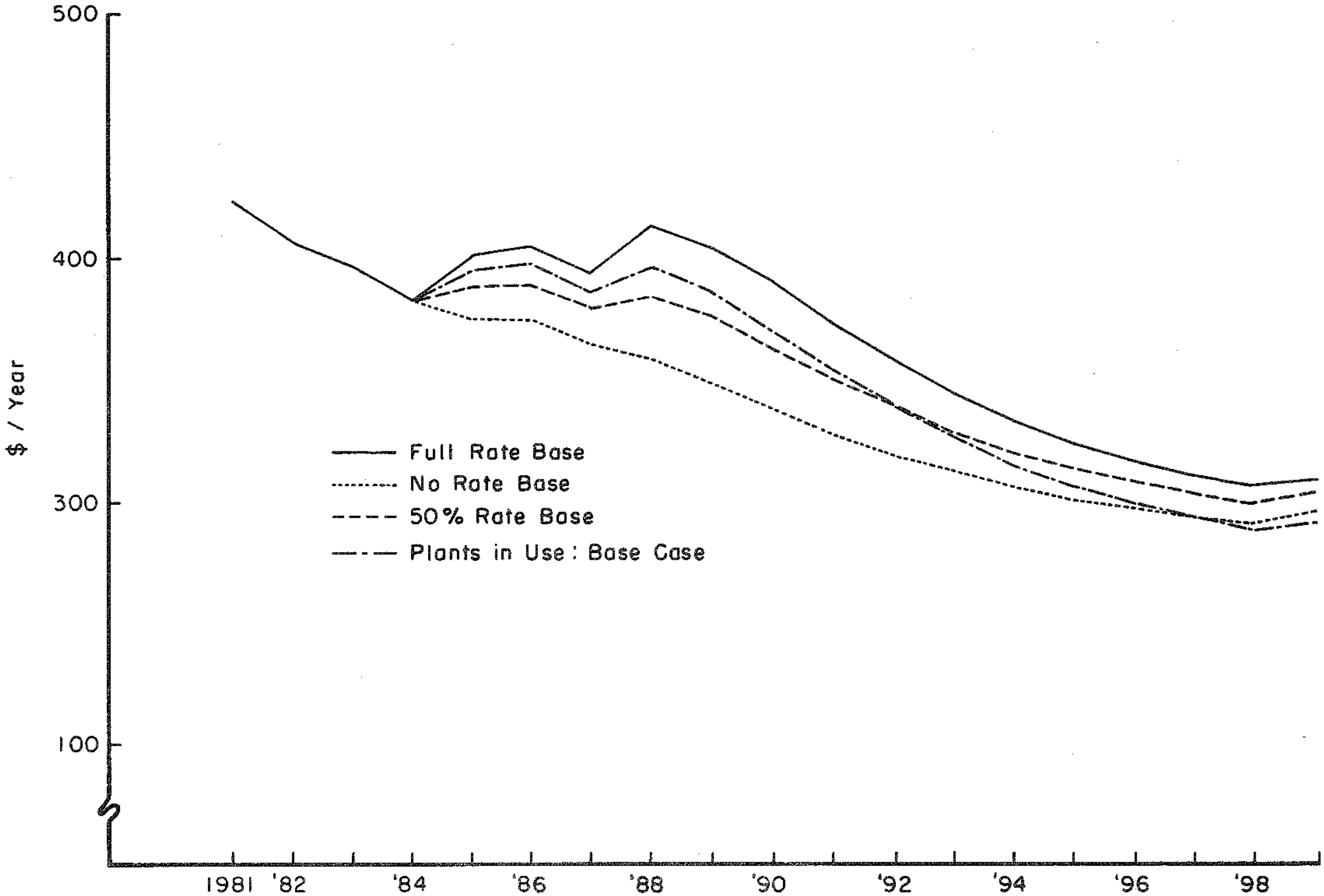


FIGURE II. TOTAL TAX PAID: NINE MILE 2 AND SHOREHAM DON'T OPERATE, RATE BASE ALLOWANCE VARIES

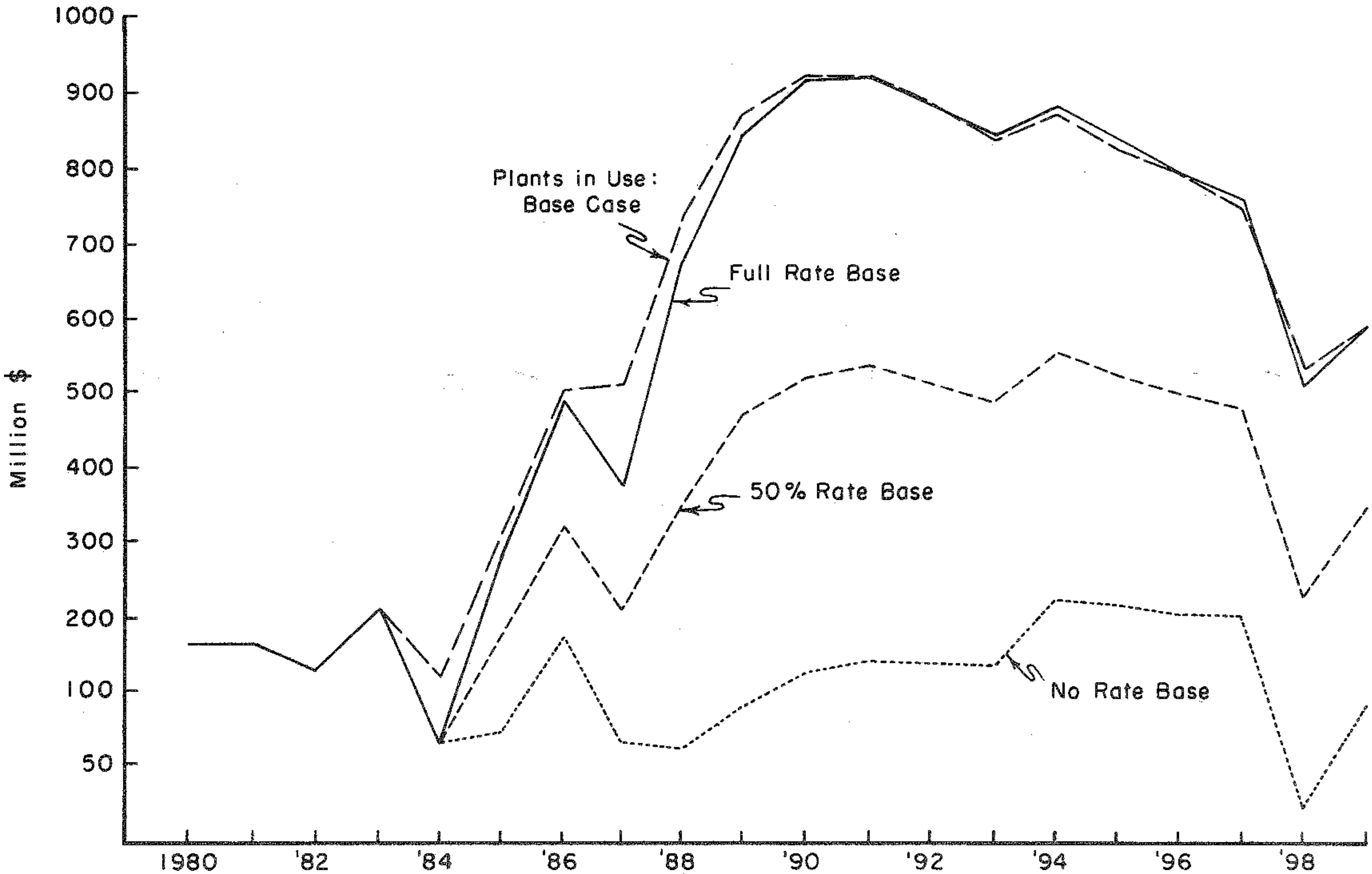


FIGURE 12. OPERATING INCOME INTEREST COVERAGE RATIO: NINE MILE 2 AND SHOREHAM DON'T OPERATE, RATE BASE ALLOWANCE VARIES

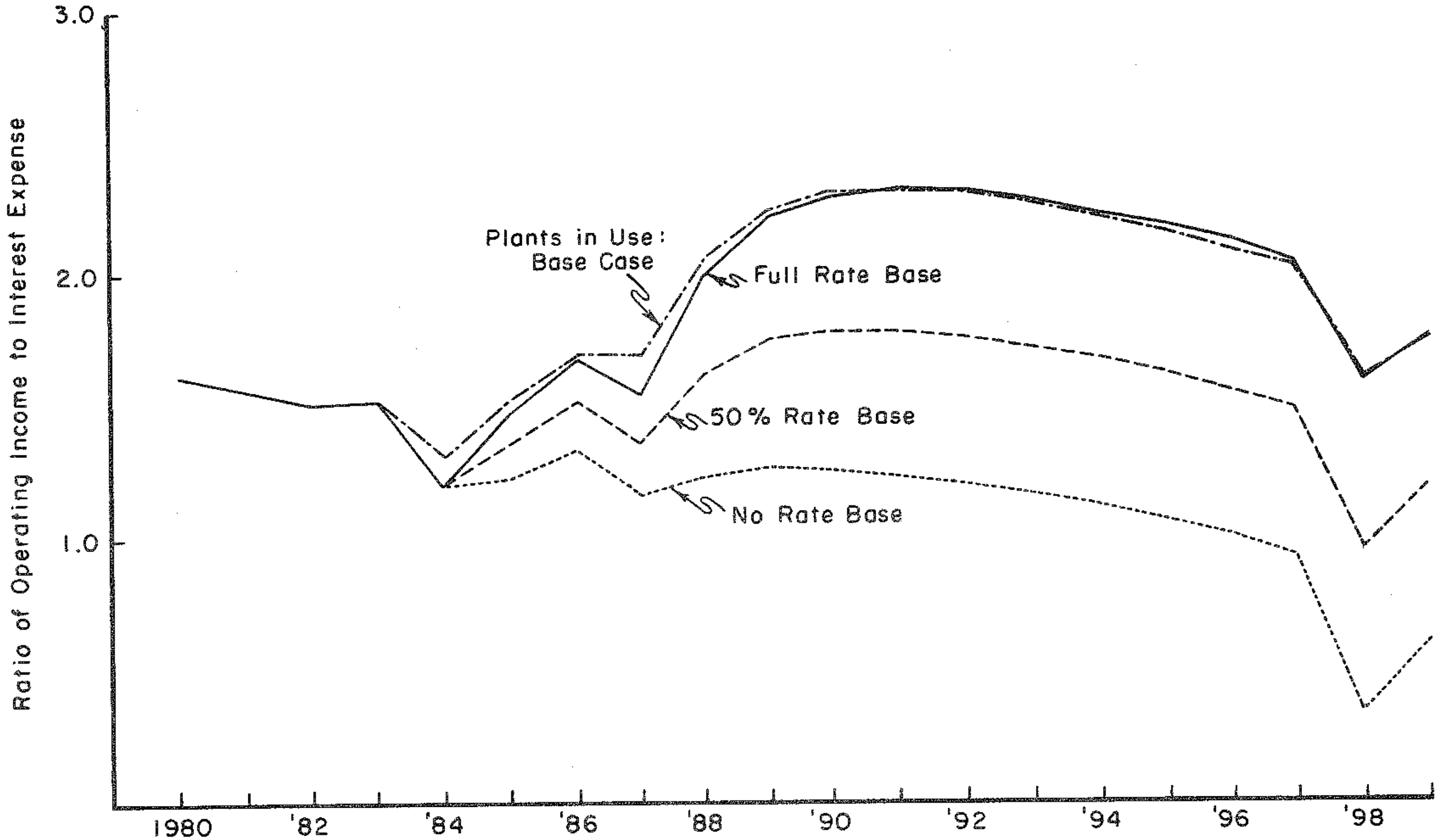


FIGURE 13. FUEL COST

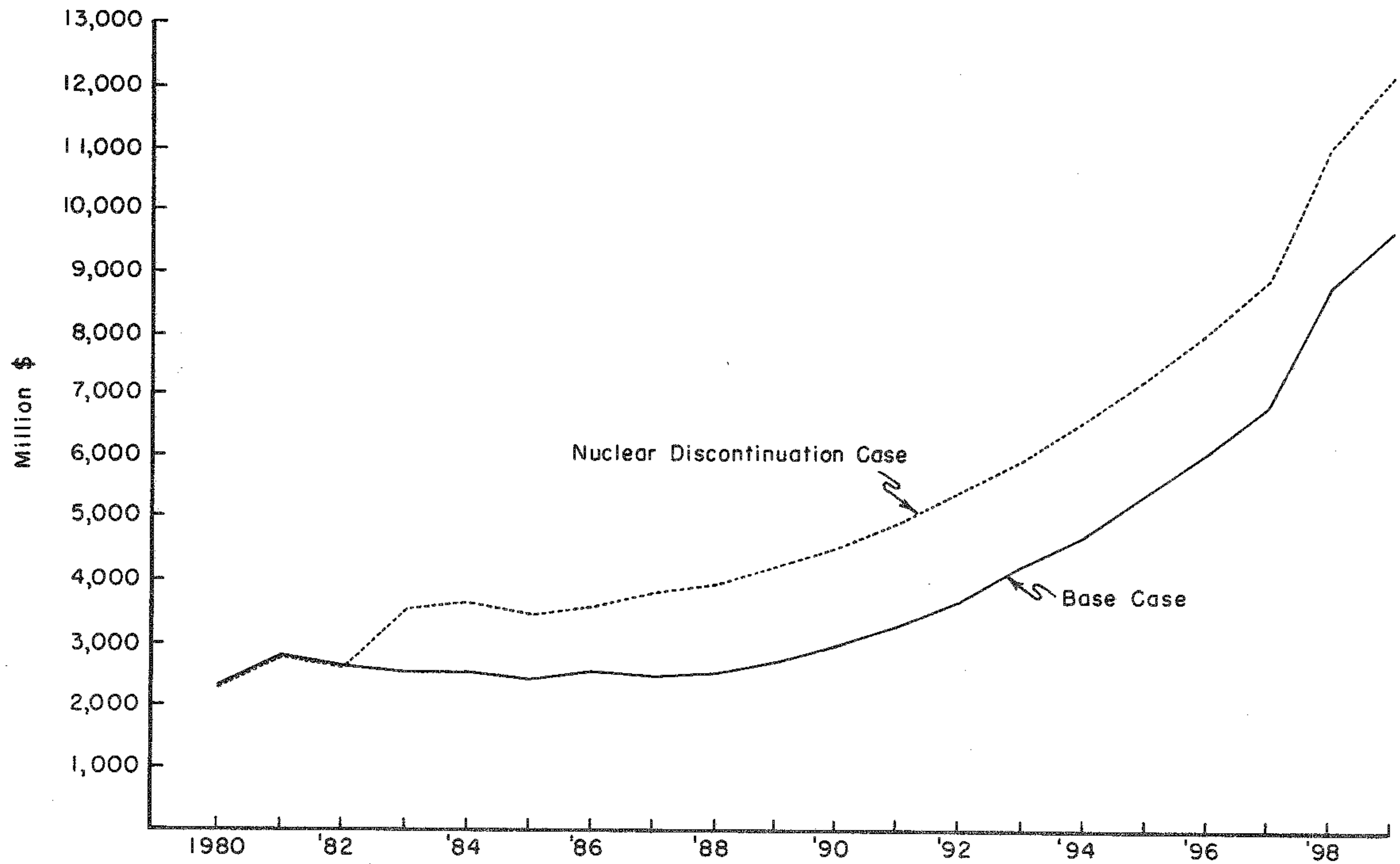


FIGURE 14. ELECTRICITY OPERATING REVENUE, MILLION $

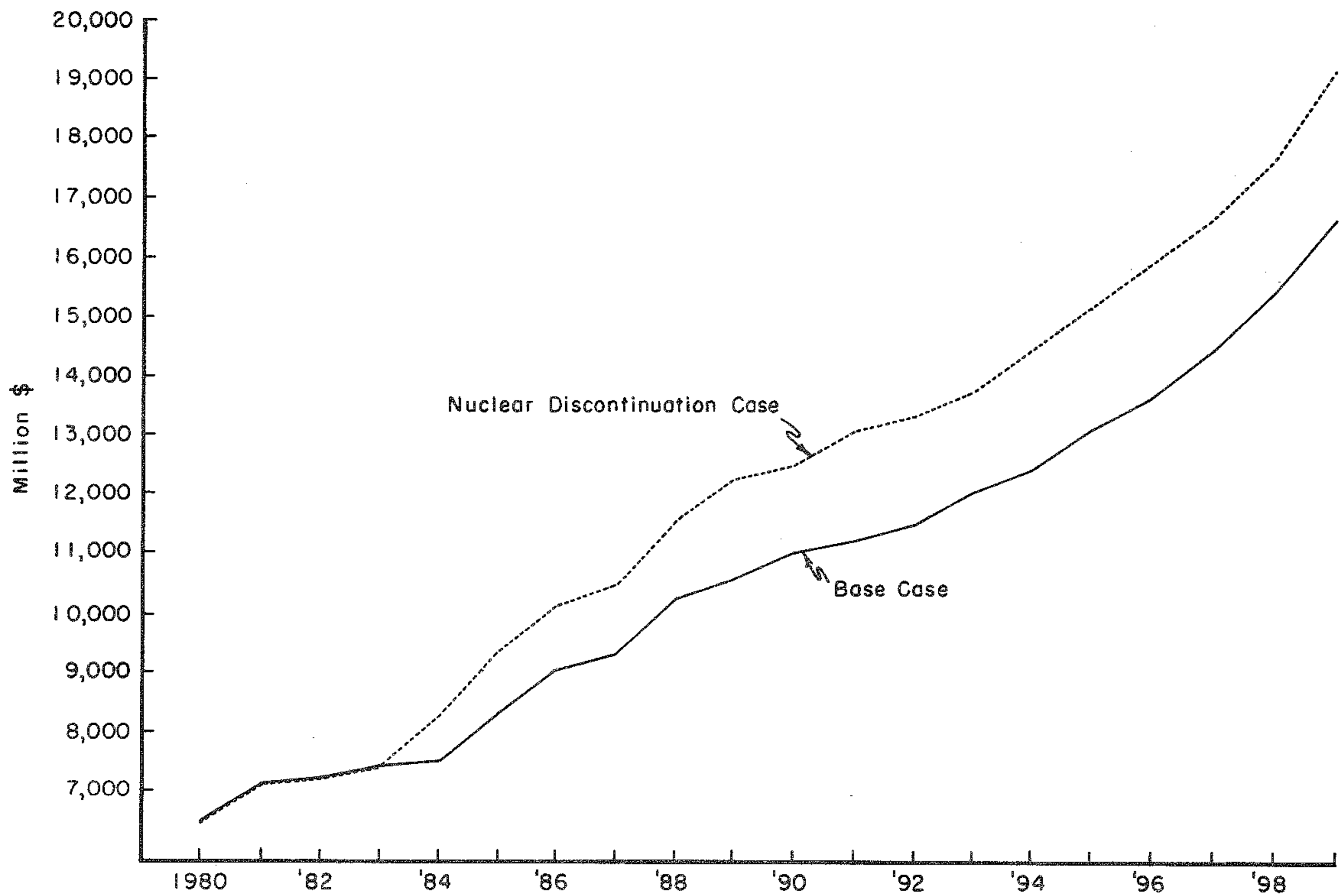
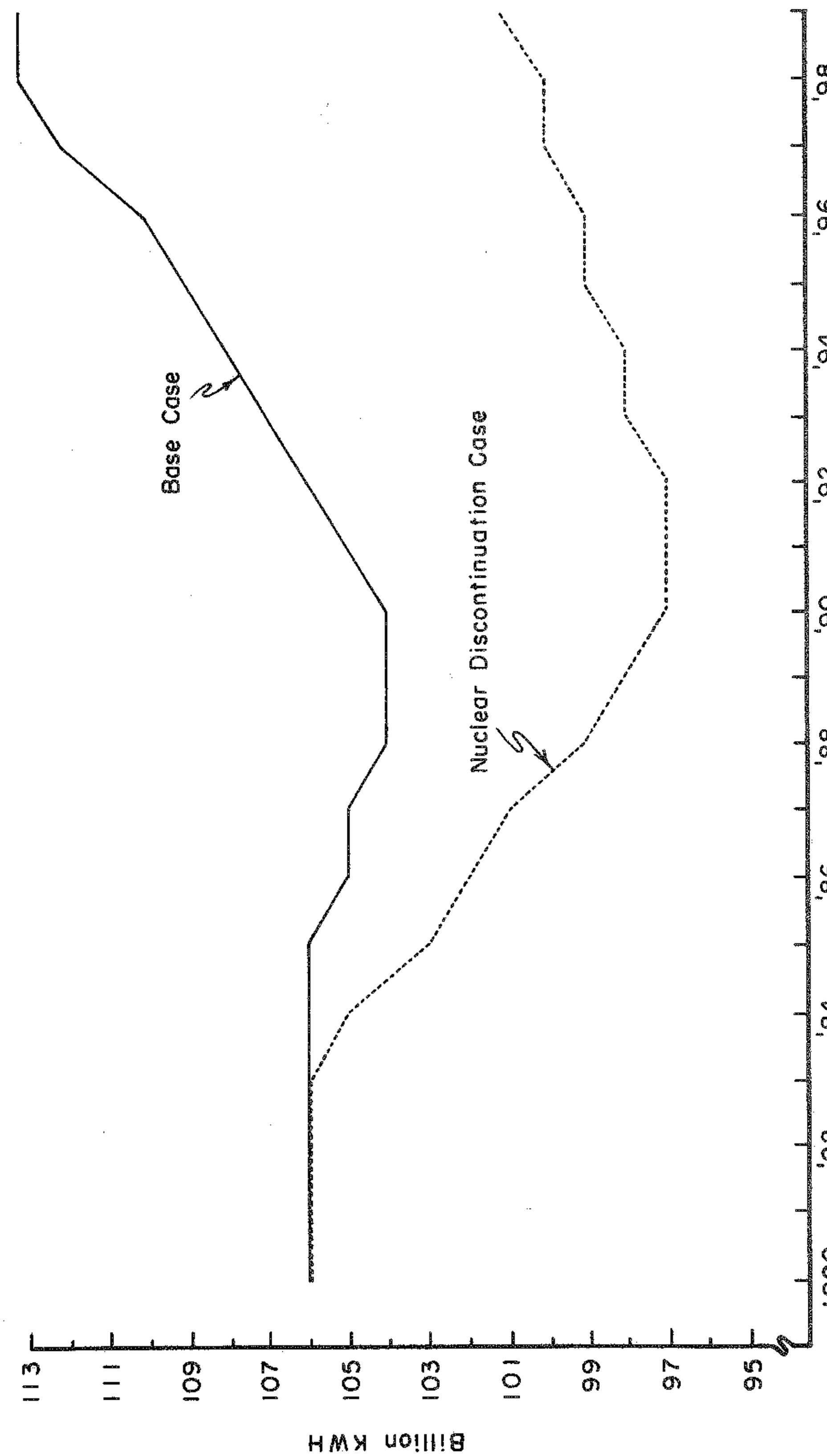
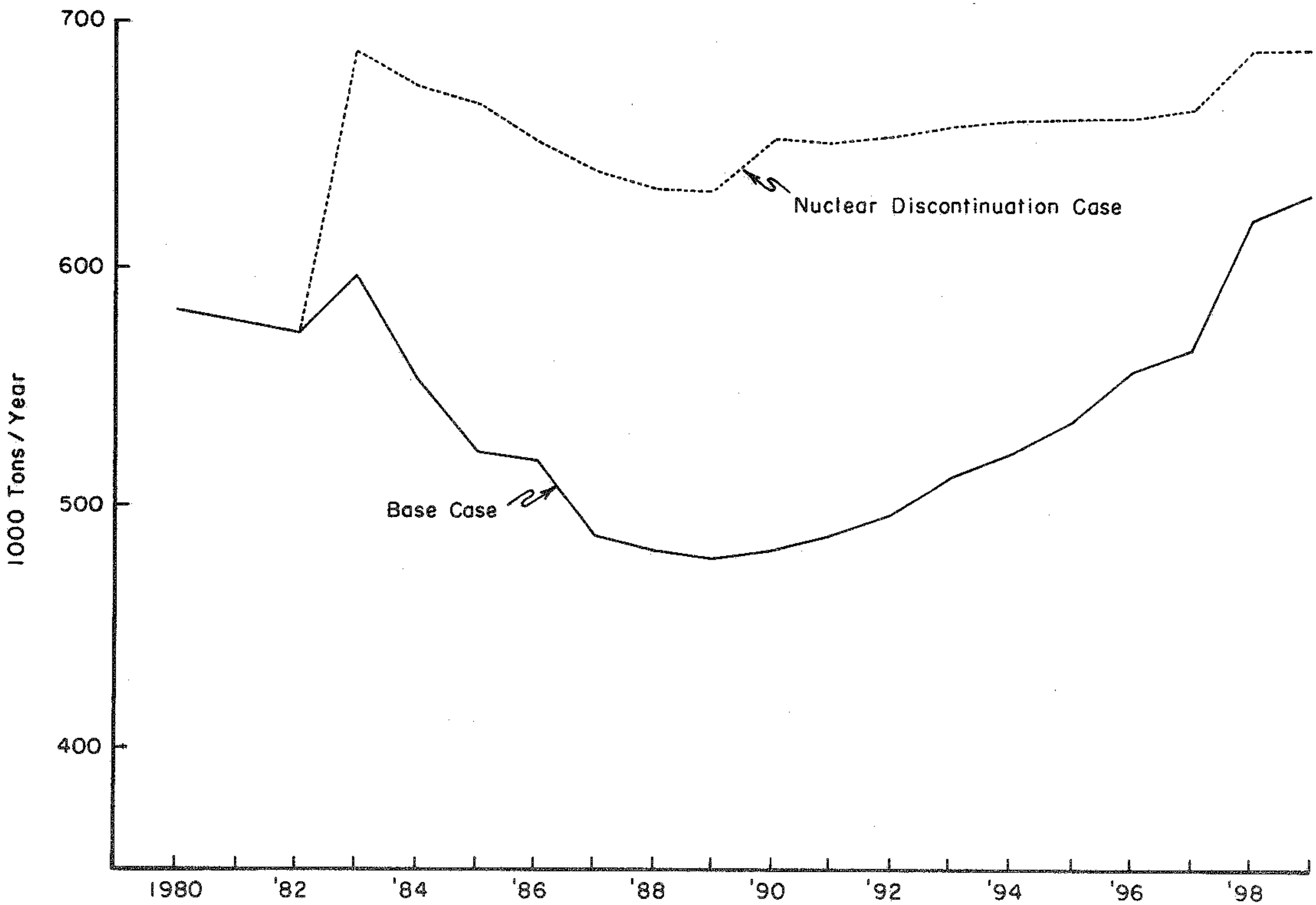


FIGURE 15. TOTAL SALES



the base case, least cost dispatching within existing emission standards results in the convex curve in Figure 16. Emissions are 580,000 tons in 1989, and rise to 630,000 at the end of the period. Without the nuclear plants--and even with the price induced lower sales--emissions exceed 650,000 tons for most of the period.

FIGURE 16. TOTAL SO_2 EMISSIONS



7. Air Pollution

Much of the current legislation under consideration uses a percentage reduction approach to state ceilings for SO_2 emissions. We made use of the CMU total emission constraint to examine cases in which SO_2 maxima decline as a falling ceiling, in 1995 being 15% of the 1980 amount. This is the lower linear-segmented curve in Figure 17.

The base case and nuclear discontinuation curves from Figure 16 are repeated in Figure 17. If the existing nuclear plants continue to operate but the Nine Mile Point #2 and Shoreham plants are unavailable, another 30,000 tons would be added to emissions. It should be remembered that it is assumed that all plants meet plant-specific standards; the variations in total emissions here arise from variations in dispatching and total sales.

Although the impact of the new Somerset coal plant is not shown separately, an analysis of its availability indicates that it does not increase emissions above the base case path. This is because of the use of sulfur scrubbing, and the displacement of sulfur emissions from oil plants.

Figure 18 shows the effect on average price with the simultaneous implementation of (1) an 85% State reduction in SO_2, and (2) a discontinuation of nuclear power. In the early 1990's, there is nearly a 1¢/kWh difference in the base case and this case. This is about 13% of the base case cost.

Sales decline to 99 billion kWh by the end of the century in this case.

FIGURE 17. SULFUR OXIDE EMISSIONS: NUCLEAR AVAILABILITY

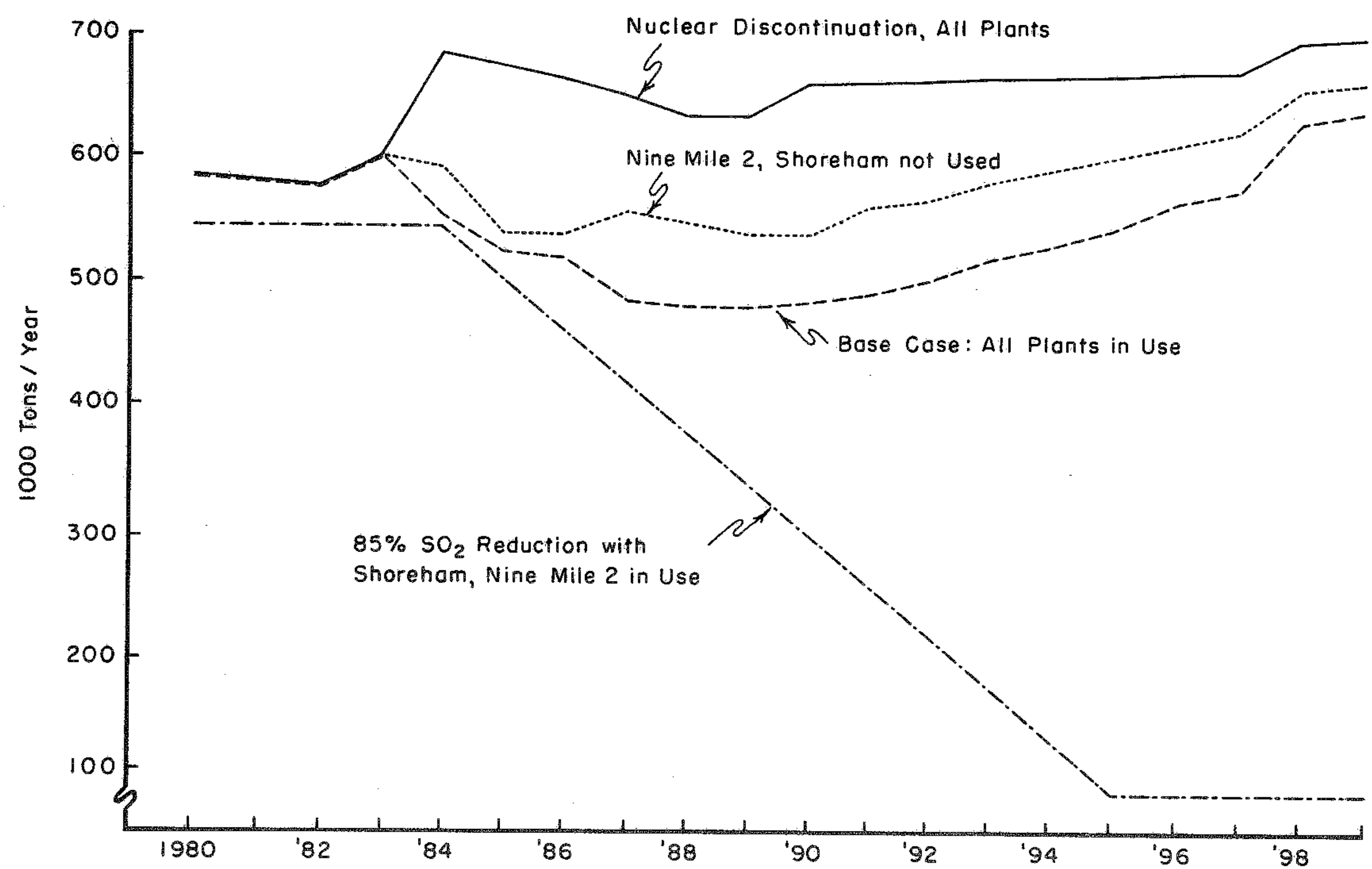
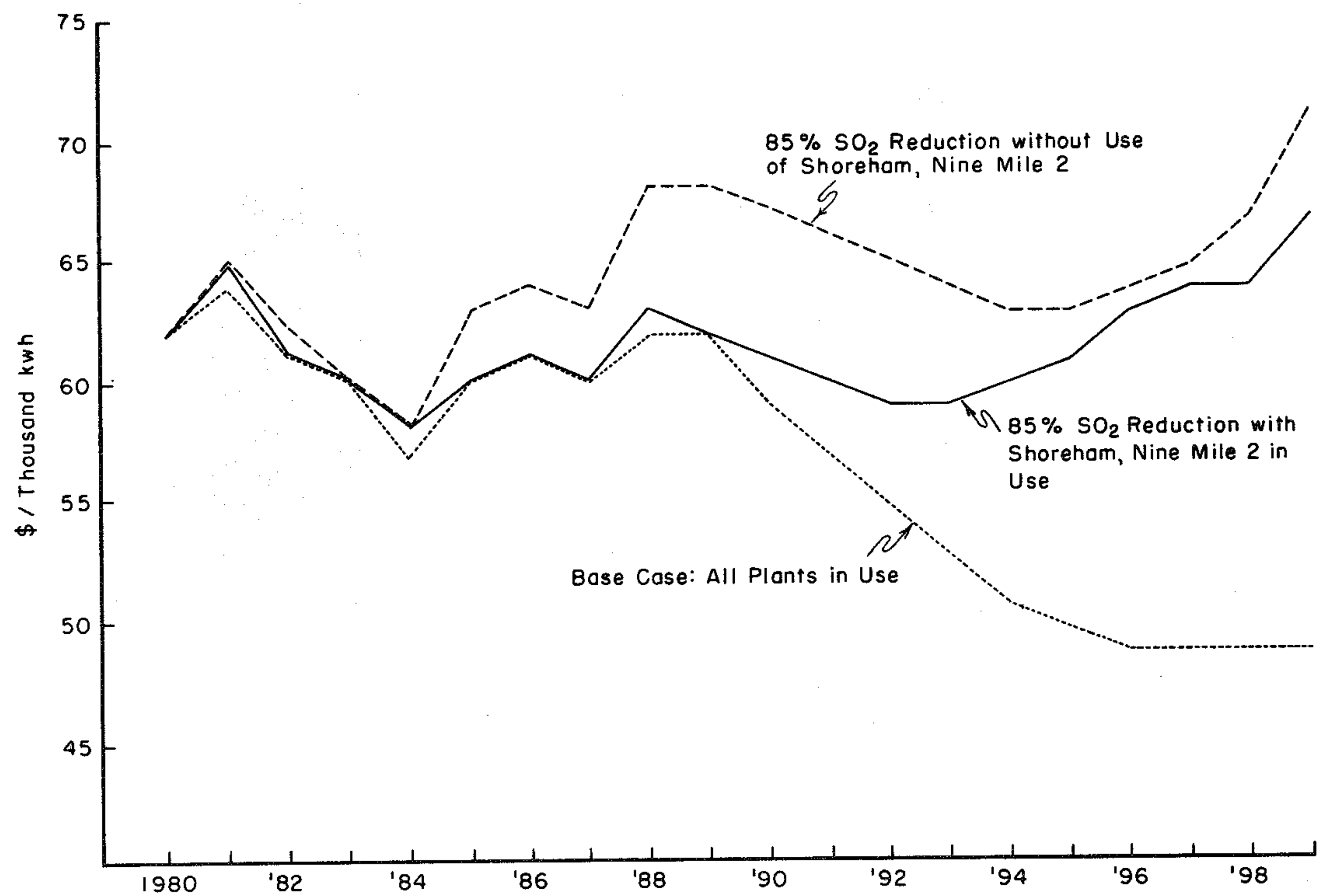


FIGURE 18. AVERAGE REAL PRICE: AIR POLLUTION AND NUCLEAR AVAILABILITY



8. Economic Growth and Oil Prices

The scenarios discussed in the preceding two sections dealt with policy analysis of subjects that focus upon the utility industry: the availability of nuclear power and air pollution control. In this section, the focus is on the influence of external economic factors. For example, economic growth implies higher levels of income and employment, which in turn will stimulate the demand for electricity. Another external effect is that higher prices for primary fuels tend to increase demand directly through the substitution of electricity for primary fuels. Electric resistance heating and electric arc furnaces are examples of end uses that are competitive with primary fuels. There is also an indirect effect of higher fuel prices because higher costs of generation will be passed on as higher prices for electricity. This indirect effect on demand will tend to offset the substitution effects.

To demonstrate that the demand for electricity could grow substantially, a set of "optimistic" assumptions are used to specify inputs. First, the economy is assumed to grow in real terms, and this is associated with higher levels of employment and population. The real price of coal declines, and in addition, nuclear plants operate at capacity factors similar to those of coal plants. Hence, this scenario represents a situation in which three major problems currently facing the industry are eliminated.

The input assumptions and the results for the "high growth" scenario are summarized in Tables 10 and 11. The most important result is that sales increase to 142 billion kWh in 1999, compared to 113 billion kWh in the base case. The corresponding level of generation is 150 billion kWh. Most of the additional generation in the high growth case comes from oil and nuclear plants. This is because the nuclear plants are assumed to operate at higher capacity factors in this case, and more oil generation fills the remaining requirements. The increased use of oil leads to higher levels of emissions, and to higher average costs than the base case.

The projected level of generation in the high growth case is somewhat higher than the level forecasted this year by the New York Power Pool (NYPP) for 1999 (141 billion kWh). The pattern of generation is somewhat different, however, because it is assumed in the NYPP forecast that some oil plants are converted to coal burning. Since the price of oil declined recently, it is probable that plans for coal conversion will be delayed.

Table 10. Input Assumptions for Economic Variables (Annual Growth Rates for 1983 to 1999).

	Scenario		
	Base	High Growth	High Oil Price
1. Total Personal Income	6	8	6
2. Employment	0	1	0
3. Population	0	.5	0
4. Price of oil	9	9	16
5. Price of natural gas	10	10	16
6. Price of coal	7	5	11
7. Price of nuclear fuel	7	7	11
8. Inflation	6	6	6
Maximum Operating Capacity Factor for Nuclear Plants	57.5%	77.0%	57.5%

For the scenario in which fuel prices increase substantially, it is assumed that the prices of oil and natural gas increase at 10 percent each year above the rate of inflation, and the corresponding rates for coal and nuclear fuel are both 5 percent. In all other respects, the high oil price scenario is identical to the base case. It should be noted that even though the price increases may seem large in the light of current experience, the growth rate for the price of oil is lower in real terms than the actual rate that existed from 1973 to 1981.

Given the importance of oil-fired capacity in New York State, it is not surprising to find that average costs increase sharply with higher oil prices. Sales fall slightly from 106 billion kWh in 1980 to 105 billion kWh in 1999. The average price paid in 1999 is, however, almost double the corresponding price in the base case. Given the large increase of price, it may seem surprising that sales are not lower. The reason is that the higher prices for primary fuels result in the substitution of electricity for primary fuels. For example, although the average price of electricity increases by roughly 50 percent in real terms from 1985 to 1999, the equivalent increase in the price of residual oil is over 400 percent.

Table 11. Forecasts Under Alternative Economic Conditions.

		Scenario		
		Base	High Growth	High Oil Prices
1. Sales (billion kWh)	1980	106	106	106
	1985	106	111	106
	1990	104	119	104
	1999	113	142	105
2. Generation by Source in 1999 (billion kWh)	Hydro	27	27	27
	Nuclear	28	37	28
	Coal	27	28	26
	Oil	31	44	15
	Natural Gas	4	14	12
	Total	117	150	108
3. Total Emissions of SO_2 (thousand tons)	1980	582	582	582
	1985	523	520	522
	1990	482	549	449
	1999	632	707	481
4. Average Price of Electricity in mills/kWh (1980 $)	1980	62	62	62
	1985	60	57	64
	1990	59	55	71
	1999	49	54	97

In comparison to the base case, generation in 1999 is 9 billion kWh lower with high oil prices. The use of oil for generation is substantially lower than in the base case, partly due to the lower level of demand and partly due to a greater use of natural gas. Using less oil implies that emission levels are lower. With high oil prices, SO_2 emissions drop by approximately 17 percent over the forecast period, whereas in the base case, SO_2 emissions increase by 8 percent.

Two conclusions should be emphasized. The first is that since oil provides the most expensive source of electricity, changes in the level of demand affect the use of oil and emissions from oil. Emissions from coal plants are very similar in all three scenarios even though sales in 1999 range from 105 to 142 billion kWh. The second conclusion is that it is important to distinguish cost increases that affect electricity only, such as controlling emissions, from cost increases caused by higher fuel prices. In the former case, the demand for electricity is more responsive to price, and this is the type of response discussed in section 5. In the latter case, substitution effects partially compensate for changes in the price of electricity. Hence, it is not correct to assume that the demand for electricity will respond in the same way to all increases of the price of electricity.

9. The Effect of Rate Design on Demand

All scenarios described to this point are based on the assumption that the structure of rates reflects the actual cost of service to customers. With this procedure, rates usually have a declining block structure. The customer charge reflects costs such as those for maintaining local distribution systems and for processing bills. The resulting price charged for each additional kWh depends on the average cost of producing electricity from all sources. Economic theory suggests that the efficient price to charge for a product should equal the incremental cost of production (i.e. the cost of power from a new plant).[15] The type of plant used to derive the cost of power should represent a cost-effective choice, and not necessarily the last plant built. For this reason, a coal plant is used in the example below rather than a nuclear plant. From the point of view of economic efficiency, a declining block structure was appropriate in the growth period before 1970 when the cost of power from new plants was lower than the average cost. During that period, most rate hearings resulted in lower rates. The implication of efficient pricing for the current situation is that marginal prices would be higher than average prices. To ensure that revenues received cover actual costs and do not result in excess profits, customer charges might be negative.

Incremental cost pricing would include fuel costs, other operating costs and costs for generation, transmission and distribution networks. Consequently, industrial customers would still pay lower marginal prices than residential and commercial customers because distribution costs would be lower.

If the marginal prices charged in different sectors are determined by incremental costs, customer charges must be set to keep revenue received close to allowed revenue. In the example below, the customer charges for different sectors are calculated to maintain stability in the share of total revenue coming from each sector, and in the average prices paid in each sector. An alternative procedure would be to assign customer charges to the residential sector only, and in this case, average prices would increase substantially for commercial and industrial customers.

The incremental cost of power in New York State is derived from information given in the annual report of the New York Power Pool for a new coal plant (Somerset) that will operate with scrubbers.[16] (Power from the two nuclear plants that are under construction is reported to be much more expensive.) The costs of transmission and distribution are specified to be 15 and 25 percent of the total incremental cost, respectively, and the latter cost is used to determine the difference between the industrial rate and the rate charged to residential and commercial customers. All non-fuel components of the incremental cost are assumed to increase at the rate of inflation, and the cost of coal is determined by the specific assumptions for fuel prices in the scenario. Finally, it is assumed that a gradual transition from current rates to the new rate structure occurs over a period of five years from 1985 to 1989. Consequently, incremental cost pricing is fully implemented throughout the nineties.

The implications of incremental cost pricing are illustrated in Table 12 for 1990. While the average cost of power is 59 mills/kWh, the incremental cost is 87 mills/kWh. Under average cost-of-service pricing, which is used for the base case, the marginal prices in the residential and commercial sectors are lower than the corresponding average prices and industrial rates are approximately flat. With incremental cost pricing the marginal prices are all higher than the average prices. The average price for all sectors is slightly higher with incremental cost pricing because the revenue received is higher than allowed revenue. However, the size of this discrepancy between average price and average cost gets smaller as rates are adjusted in later years.

Another way of illustrating the effects of incremental cost pricing is to consider the cost of purchasing different amounts of electricity. For example, the monthly bills for residential customers are summarized in Table 13 for the two different rate structures. The bills for 500 kWh/month are similar with either rate structure, but the bill is lower for 250 kWh/month and higher for 750 kWh/month with incremental cost pricing. With incremental cost pricing, a decision to cut use from 500 to 250 kWh/month saves more ($22 instead of $15), and a decision to increase use costs more. Consequently, if incremental costs are higher than average costs, incremental cost pricing will encourage conservation. This would be an important factor in the selection of heating systems, for example, because electricity competes directly with primary fuels. In addition, there would be an added incentive to purchase efficient appliances because savings are greater. It

Table 12. A Comparison of Alternative Rate Structures for 1990 (mills/kWh in 1980 dollars)

		Rate Structure	
		Average Cost of Service	Incremental Cost
Components of Total Cost			
Fuel		17	17
Operations and Maintenance		3	3
Capital		30	--
Generation		--	32
Transmission		--	13
Distribution		--	22
Purchased Power		9	--
Total		59	87
Prices Charged to Customers			
Marginal Price	Residential	59	87
	Commercial	63	87
	Industrial	41	65
Average Price	Residential	72	72
	Commercial	72	69
	Industrial	41	47
	All sectors	59	61

Table 13. Monthly Bills for Residential Customers in 1990 (1980 dollars)

Level of Use (kWh/month)	Rate Structure: Average Cost of Service	Rate Structure: Incremental Cost
250	20.43	16.12
500	35.13	37.82
750	49.83	59.52

should be noted that although customers receive a rebate with incremental cost pricing, some form of minimum bill policy would inevitably be implemented, so that bills would never become negative at low levels of use.

The effect of incremental cost pricing on emissions depends entirely on how the level of sales is affected. The results of four alternative scenarios are summarized in Table 14. Since the transition to incremental cost pricing is assumed to begin in 1985, attention is directed to the forecasts for 1990 and 1999. Scenario A corresponds to the base case with average cost-of-service pricing, and scenario B is the corresponding case with incremental cost pricing. In addition, scenarios C and D are cases, for the two rate structures, in which the two nuclear plants currently under construction are never brought on-line, but are still paid for in full by ratepayers. This situation implies that average costs increase.

A comparison of scenarios A and B shows that sales are substantially lower when incremental cost pricing is implemented, resulting from the fact that incremental costs are much higher than average costs in this example. Unlike the base case (A), sales decline throughout the nineties because the marginal prices increase when coal prices increase. Average costs decrease in real terms from 1990 to 1999 in all scenarios, because the size of the rate base declines. This is reflected by the drop in the average prices paid. It should be noted that the average price in 1999 is much lower in scenario B than in the base case because of a reduction in the use of expensive oil plants. Given the lower sales in scenario B, emissions of SO_2 are substantially less than in the base case, and by 1999, they are only two thirds of the level in the base case.

Table 14. The Sensitivity of Forecasts to the Structure of Rates.

Input Assumptions		Scenario A	B	C	D
Economic growth		Base	Base	Base	Base
Fuel Prices		Base	Base	Base	Base
Rate Structure		Av. Cost	Inc. Cost	Av. Cost	Inc. Cost
2 Nuclear Plants		On-line	On-line	Off-line	Off-line
Results					
1. Sales (billion kWh)	1990	104	91	102	91
	1999	113	87	109	87
2. Generation by Source in 1999 (billion kWh)	Hydro	27	27	27	27
	Nuclear	28	27	18	18
	Coal	27	23	28	26
	Oil	31	8	33	13
	Nat. Gas	4	3	7	4
	Total	117	88	113	88
3. Total Emissions of 1990 SO_2 (thousand tons)	1990	482	404	537	464
	1990	631	412	653	483
4. Average Price of Electricity in mills/kWh (1980 $)	1990	59	61	63	64
	1999	49	40	53	44

In scenarios C and D, the additional cost of fuel needed to replace generation from the two nuclear plants must be covered by additional revenue. With average cost-of-service pricing, these additional revenues are collected by raising marginal prices. As a result, sales are lower in scenario C than in the base case. A comparison of scenarios D and B, however, shows that sales are the same in both cases, although the patterns of generation are different. With incremental cost pricing based on the cost of power from a new coal plant, the marginal prices are not affected by the availability of nuclear plants. The additional revenue is obtained by revising customer charges, and this has virtually no effect on sales.

The results presented in Table 14 require some additional qualifications. First, economic conditions, and in particular the levels of employment, are the same in all scenarios. With incremental cost pricing, however, higher marginal prices for industrial customers could lead to firms moving to other states. Second, the transition from cost-of-service pricing to incremental cost pricing is relatively gradual. Large unexpected increases in customer charges could reduce sales more than is implied by the model in scenarios C and D. The additional fuel costs associated with the unavailability of two nuclear plants in those scenarios are covered by all customers in the state. Consequently, the percentage increase in cost is much smaller than it would be if the cost were borne entirely by customers in a small service territory.

In the preceding section, economic conditions, beyond the control of utilities, were shown to influence the level of demand for electricity, and consequently the level of emissions. In this section, substantial changes in demand and emissions were shown to result from modifying the structure of rate schedules. In other words, there is nothing inevitable about the growth of demand. Some factors that affect demand can not be controlled, but others, such as the treatment of capital costs and the structure of rates, are determined by regulatory policy. Furthermore, costs can be passed on to customers in different ways, and a given cost increase can result in quite different responses in the level of sales. To a large extent, levels of SO_2 emissions will depend on whether policies are adopted to encourage conservation or to encourage growth in the use of electricity.

10. Conclusions

We have studied the potential for physical or financial disruption of the electric utility system in New York as it may be affected by nuclear power availability, air pollution control policy, inflation, and economic growth. The method of analysis is the EPA-sponsored CCMU model which integrates utility economics, demand forecasting and customer charges, air pollution control, and power plant dispatching. The CCMU model is a partial version of the AUSM; the latter model is being developed to include coal supply and capacity planning.

Of all the cases examined, only one type seems to create a severe crisis which leads to possible public re-organization of the industry. These are the cases in which the Shoreham and Nine Mile 2 plants are not operated, and 50% or more of the investment cost is not allowed in the rate base. In these circumstances, the State's utilities would apparently be unable to meet debt obligations and would also need to discontinue dividend payments.

The extremity of this situation should be emphasized. These specific cases already assume that liability for debt and dividend payments has been shared equally over all of the State's utilities and customers. It assumes that the State's Power Pool has already implemented a plan by which the principal owners of the two plants are relieved of their principal financial and generating responsibilities.

In all other cases studies, the statewide industry appears capable of managing the problems examined.

Some specific findings follow:

A. In the 1970's, demand analysis modelling has a superior record when compared to exogenous growth assumptions at the national and state levels. The demand forecasts studied here define a future range of 97 to 117 billion kWh, the variation depending upon future prices. (See Figures 7 and 15).

B. Future sales could reach a level of 150 billion kWh, but this depends upon a set of assumptions which include declining coal cost, 77% capacity factor operations for all nuclear plants, and rising real income and employment. The State's utility system provides this level of sales with its present plants, the three now being completed, and planned Canadian purchases.

C. If the State's nuclear plants are all closed, the least-cost dispatching solution increases net fuel costs and customer charges by $1.5 billion in the early 1990's. However, if the State system is allowed to collect the capital cost from customers, the system can provide the electricity demanded and meet its financial obligations.

D. Higher oil and other fuel prices increasing at rates of 5%-7% annually in real terms would double the real price of electricity. However, because of the substitution effect in which higher retail fuel costs for natural gas, et al. increases electricity demand, the total sales of electricity would apparently remain at present levels.

E. If the State's total sulfur oxide emissions were reduced to 15% of their 1980 magnitude, and the Shoreham and Nine Mile 2 nuclear plants were unavailable, the least-cost generating pattern would require a 25%-50% increase in electricity rates in the 1990's.

F. Addition of the Somerset coal plant to the State's system does not increase total sulfur oxide emissions above the base case. This is because least-cost dispatching displaces sulfur-emitting oil generation.

G. Significant revision in national corporate income taxation may add up to $1 billion to the actual Federal corporate income tax payments by utilities in the State.

Two generalizations for continuing research arise from this study. First, some problems will require State-level responses. Assuming that such State planning occurs, our work might develop an individual utility component to show the company-specific responses to particular state policies.

Second, it is clear that further national gains in air pollution control are going to be complex and costly. They are likely to include financial provisions which redistribute the cost over time and between regions. In this context, economic and financial analysis is equivalent to engineered levelized cost in studying specific policies.

This leads us to point to two forms of financial policies which are probable candidates for future legislation. One is tax incentives such as a 50% investment tax credit or a 5-year tax depreciation schedule for pollution control investment. The rationale here is that the benefits of pollution control are widespread and public, thereby justifying national tax incentives.

Second, tax charges on emissions and fuel use may be considered as a means of financing pollution control investment. The logic here is that the corporations and customers associated with present emissions are responsible for the cost of control.

Ultimately, we may see Federal legislation which combines both tax incentives and tax charges, incorporating both rationales for financing further air pollution control improvement.

Footnotes

1. See Mount and Chapman, 1975. Actual generation levels are taken from the NYPP Annual Report, 1983.

2. See Chapman et al, 1975.

3. See Stukel.

4. See Baughman et al.

5. Contributions to the CCMU model, with emission constraint:
   A. Least cost linear programming dispatching model: Sarosh Talukdar and Navin Tyle, CMU.
   B. Plant standards and plant implementation of SO_x regulations. Coal washing, SO_x scrubbing, particulate removal technologies and costs: Ed Rubin, John Molburg, Cary Bloyd*, Jim Skea, CMU.
   C. New York plant and fuel data: Gene Fry, CU.
   D. Demand model: Tim Mount, Martha Czerwinski, CU.
   E. Finance model: Kathleen Cole*, Mark Younger, CU.
   F. Policy analysis programming: Martha Czerwinski, Mark Younger, CU.
   G. Administrative responsibility: Tim Mount, Duane Chapman, CU.
   *See analytical documentation by Cole, Bloyd et al, Talukdar, and Mount in the References.

6. Similar to D. Chapman, Natural Resources Journal. Key assumptions are an \$851/kW cost (in 1980\$) for a plant built between 1980 and 1990, a 9% general inflation rate, a 13.5% construction cost escalation, and a future decommissioning cost of \$65 million in 1983 dollars. Figure 11 is based upon a current utility tax law as revised in 1982.
   An introductory discussion of cost of service and utility rate regulation is in Chapman, Energy Resources and Energy Corporations, pp. 229-240.

7. See EEI Yearbook for 1981, p. 71.

8. See EEI Yearbook for 1981, p. 91.

9. See Taylor and Oi.

10. In some instances, the fuel component may be higher than the marginal price paid in the industrial sector, and a minimum contribution to non-fuel costs is imposed.

11. See Mount, 1983.

12. Elasticity is the percentage response of sales to a one percent increase of an explanatory variable, holding other variables constant.

13. See NYPP Annual Report, Volume I, p. 40.

14. The difference between sales and generation accounts for distribution losses and the net transfer of power into the state from Canada. The specific pro-

cedures used to determine generation from sales are described in section 2.

15. See Turvey, chapter 8.

16. Derived from the NYPP Annual Report, 1983, Volume 2, p. 46.

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Appendix A.

	NAME	PLANT	PLANT CHARACTERISTICS FUEL	OWNER	SIZE MW	HT RATE MBTU/MWHR	O&M COST $/MWHR	SULPHUR STANDARDS S LB/ MBTU	S % BY WT	EST SO2 /MBTU	TSPSTD LB/MBTU
1	GOUDEY	ST. TURB	COAL	NYSEG	129.	10.999	2.74	1.90	0.0	3.80	0.10
2	GREENRIDGE	ST. TURB	COAL	NYSEG	204.	11.715	4.64	1.90	0.0	3.80	0.10
3	HICKLING	ST. TURB	COAL	NYSEG	87.	14.049	4.52	1.90	0.0	3.80	0.10
4	JENNISON	ST. TURB	COAL	NYSEG	76.	13.926	4.01	1.90	0.0	3.80	0.10
5	MILLIKEN	ST. TURB	COAL	NYSEG	305.	9.435	2.31	1.90	0.0	3.80	0.10
6	HOMER CITY	ST. TURB	COAL	NYSEG	944.	10.346	1.96	2.00	0.0	4.00	0.10
7	HUNTLY	ST. TURB	COAL	N.MOH	785.	10.657	2.80	1.40	0.0	2.80	0.10
8	DUNKIRK	ST. TURB	COAL	N.MOH	600.	10.305	2.51	1.90	0.0	3.80	0.10
9	RUSSELL	ST. TURB	COAL	RG&E	260.	10.617	4.44	1.90	0.0	3.80	0.10
10	BEEBEE 12	ST. TURB	COAL	RG&E	80.	9.740	-6.93	1.90	0.0	3.80	0.10
11	JAMESTOWN	ST. TURB	COAL	JAMES	60.	14.617	7.19	1.90	0.0	3.80	0.10
12	C. HUDSON MISC.	HYDRO	H2O	C.HUD	46.	0.0	16.17	0.0	0.0	0.0	0.0
13	NYSEG MISC.	HYDRO	H2O	NYSEG	38.	0.0	2.00	0.0	0.0	0.0	0.0
14	N.MOH 18 SITES	HYDRO	H2O	N.MOH	436.	0.0	1.99	0.0	0.0	0.0	0.0
15	N.MOH MISC.	HYDRO	H2O	N.MOH	220.	0.0	2.25	0.0	0.0	0.0	0.0
16	ORANGE & ROCKLAND	HYDRO	H2O	ORANG	34.	0.0	5.67	0.0	0.0	0.0	0.0
17	MOSES NIAGARA	HYDRO	H2O	PASNY	2400.	0.0	0.32	0.0	0.0	0.0	0.0
18	MASSENA	HYDRO	H2O	PASNY	800.	0.0	0.26	0.0	0.0	0.0	0.0
19	RG&E MISC.	HYDRO	H2O	RG&E	47.	0.0	2.00	0.0	0.0	0.0	0.0
20	INDIAN PT 2	NUCLEAR	NUCL	CONED	849.	11.986	6.81	0.0	0.0	0.0	0.0
21	NINE MILE PT 1	NUCLEAR	NUCL	N.MOH	610.	10.617	3.89	0.0	0.0	0.0	0.0
22	FITZPATRICK	NUCLEAR	NUCL	PASNY	810.	10.233	8.47	0.0	0.0	0.0	0.0
23	INDIAN PT 3	NUCLEAR	NUCL	PASNY	855.	11.182	6.04	0.0	0.0	0.0	0.0
24	GINNA	NUCLEAR	NUCL	RG&E	470.	10.950	4.35	0.0	0.0	0.0	0.0
25	ROSETON	ST. TURB	OIL6	MULT.	1193.	9.852	0.92	0.0	2.00	2.05	0.0
26	DANSK N.3-4	ST. TURB	OIL6	C.HUD	352.	10.535	2.38	0.0	1.00	1.03	0.0
27	DANSK N.1-2	ST. TURB	GAS	C.HUD	124.	10.535	2.38	0.0	0.0	0.0	0.0
28	ARTHUR KILL	ST. TURB	OIL6	CONED	826.	10.686	4.15	0.0	1.50	1.56	0.0
29	ASTORIA N.4-5	ST. TURB	OIL6	CONED	766.	11.249	8.72	0.0	0.30	0.31	0.0
30	ASTORIA N.1-3	ST. TURB	GAS	CONED	685.	12.025	8.72	0.0	0.0	0.0	0.0
31	BOWLINE (A)	ST. TURB	OIL6	MULT.	1063.	10.071	1.91	0.0	0.60	0.62	0.0
32	BOWLINE (B)	ST. TURB	GAS	MULT.	139.	10.071	1.91	0.0	0.0	0.0	0.0
33	EAST RIVER (A)	ST. TURB	OIL6	CONED	211.	13.377	9.98	0.0	0.30	0.31	0.0
34	EAST RIVER (B)	ST. TURB	GAS	CONED	215.	13.377	9.98	0.0	0.0	0.0	0.0
35	HUDSON AVE.	ST. TURB	OIL6	CONED	368.	27.386	74.81	0.0	0.30	0.31	0.0
36	RAVENS. N.3	ST. TURB	OIL6	CONED	928.	10.787	5.10	0.0	1.50	1.56	0.0
37	RAVENS. N.1&2	ST. TURB	GAS	CONED	770.	10.677	5.10	0.0	0.0	0.0	0.0
38	WATERSIDE (A)	ST. TURB	OIL6	CONED	145.	16.964	20.13	0.0	0.30	0.31	0.0
39	WATERSIDE (B)	ST. TURB	GAS	CONED	153.	16.964	20.13	0.0	0.0	0.0	0.0
40	59TH STREET	ST. TURB	OIL6	CONED	92.	14.006	47.08	0.0	0.30	0.31	0.0
41	74TH STREET	ST. TURB	OIL6	CONED	147.	20.166	32.27	0.0	0.30	0.31	0.0
42	NORTHPORT	ST. TURB	OIL6	LILCO	1480.	10.158	2.19	0.0	2.29	2.32	0.0
43	PORT JEFF	ST. TURB	OIL6	LILCO	476.	10.514	2.07	0.0	2.80	2.83	0.0
44	GLENWOOD (A)	ST. TURB	OIL6	LILCO	45.	11.928	10.61	0.0	1.00	1.04	0.0
45	GLENWOOD (B)	ST. TURB	GAS	LILCO	179.	11.928	10.61	0.0	0.0	0.0	0.0
46	BARRETT (A)	ST. TURB	OIL6	LILCO	51.	10.693	2.03	0.0	1.54	1.61	0.0
47	BARRETT (B)	ST. TURB	GAS	LILCO	329.	10.693	2.03	0.0	0.0	0.0	0.0
48	FAR ROCKAWAY	ST. TURB	OIL6	LILCO	112.	11.850	12.35	0.0	0.30	0.31	0.0
49	OSWEGO 1-5	ST. TURB	OIL6	N.MOH	1175.	11.323	1.77	0.0	2.28	2.37	0.0
50	OSWEGO 6	ST. TURB	OIL6	MULT.	850.	10.927	1.77	0.0	1.00	1.04	0.0
51	ALBANY	ST. TURB	OIL6	N.MOH	400.	10.352	1.89	0.0	1.00	1.03	0.0
52	LOVETT (A)	ST. TURB	OIL6	ORANG	95.	11.121	2.73	0.0	0.37	0.39	0.0
53	LOVETT (B)	ST. TURB	GAS	ORANG	406.	11.121	2.73	0.0	0.0	0.0	0.0
54	ASTORIA 6	ST. TURB	OIL6	PASNY	825.	10.155	2.40	0.0	0.30	0.31	0.0
55	BEEBEE 1	ST. TURB	OIL6	RG&E	93.	9.740	-6.93	0.0	2.00	2.04	0.0

NAME	PLANT	PLANT CHARACTERISTICS FUEL	OWNER	SIZE MW	HT RATE MBTU/MWHR	O&M COST $/MWHR	SULPHUR STANDARDS S LB/ MBTU	S % BY WT	EST SO2 /MBTU	TSPSTD LB/MBTU
56 COXS. PEAK. (A)	COMBUST.	OIL2	C.HUD	12.	13.496	74.97	0.0	0.0	0.0	0.0
57 COXS. PEAK. (B)	COMBUST.	GAS	C.HUD	7.	13.496	74.97	0.0	0.0	0.0	0.0
58 S. CAIRO PEAK.	COMBUST.	OIL2	C.HUD	19.	14.339	18.84	0.0	0.0	0.0	0.0
59 ARTHUR KILL PEAK.	COMBUST.	OIL2	CONED	16.	18.112	155.69	0.0	0.0	0.0	0.0
60 ASTORIA PEAK. (A)	COMBUST.	OIL2	CONED	515.	16.166	25.90	0.0	0.0	0.0	0.0
61 ASTORIA PEAK. (B)	COMBUST.	GAS	CONED	100.	16.166	25.90	0.0	0.0	0.0	0.0
62 GOWANUS PEAK.	COMBUST.	OIL2	CONED	477.	16.893	78.91	0.0	0.0	0.0	0.0
63 HUDSON AVE. PEAK.	COMBUST.	OIL2	CONED	68.	17.910	371.85	0.0	0.0	0.0	0.0
64 BUCHANAN PEAK.	COMBUST.	OIL2	CONED	45.	19.124	153.75	0.0	0.0	0.0	0.0
65 KENT GT. PEAK.	COMBUST.	OIL2	CONED	9.	17.683	138.06	0.0	0.0	0.0	0.0
66 NARROWS PEAK. (A)	COMBUST.	OIL2	CONED	75.	18.325	74.47	0.0	0.0	0.0	0.0
67 NARROWS PEAK. (B)	COMBUST.	GAS	CONED	197.	18.325	74.47	0.0	0.0	0.0	0.0
68 RAVENS. PEAK. (A)	COMBUST.	OIL2	CONED	107.	16.003	44.03	0.0	0.0	0.0	0.0
69 RAVENS. PEAK. (B)	COMBUST.	GAS	CONED	300.	16.003	44.03	0.0	0.0	0.0	0.0
70 WATERSIDE PEAK.	COMBUST.	OIL2	CONED	11.	18.671	467.73	0.0	0.0	0.0	0.0
71 59TH STREET PEAK.	COMBUST.	OIL2	CONED	34.	18.076	65.90	0.0	0.0	0.0	0.0
72 74TH STREET PEAK.	COMBUST.	OIL2	CONED	34.	22.390	152.59	0.0	0.0	0.0	0.0
73 NORTHPORT 6T PEAK.	COMBUST.	OIL2	LILCO	16.	33.185	165.82	0.0	0.0	0.0	0.0
74 PORT JEFF PEAK.	COMBUST.	OIL2	LILCO	16.	26.071	62.35	0.0	0.0	0.0	0.0
75 GLENNWOOD PEAK.	COMBUST.	OIL2	LILCO	114.	14.844	24.37	0.0	0.0	0.0	0.0
76 BARRETT PEAK. (A)	COMBUST.	OIL2	LILCO	52.	17.746	38.49	0.0	0.0	0.0	0.0
77 BARRETT PEAK. (B)	COMBUST.	GAS	LILCO	220.	17.746	38.49	0.0	0.0	0.0	0.0
78 SHOREHAM PEAK.	COMBUST.	OIL2	LILCO	46.	16.368	18.99	0.0	0.0	0.0	0.0
79 W. BABYLON PEAK.	COMBUST.	OIL2	LILCO	63.	20.839	30.32	0.0	0.0	0.0	0.0
80 SOUTHOLD PEAK.	COMBUST.	OIL2	LILCO	14.	26.076	134.12	0.0	0.0	0.0	0.0
81 S. HAMPTON PEAK.	COMBUST.	OIL2	LILCO	11.	17.102	204.42	0.0	0.0	0.0	0.0
82 E. HAMPTON PEAK.	COMBUST.	OIL2	LILCO	20.	16.792	25.36	0.0	0.0	0.0	0.0
83 HOLBROOK PEAK.	COMBUST.	OIL2	LILCO	465.	14.862	15.16	0.0	0.0	0.0	0.0
84 ALBANY PEAK. (A)	COMBUST.	OIL2	N.MOH	48.	16.440	34.05	0.0	0.0	0.0	0.0
85 ALBANY PEAK. (B)	COMBUST.	GAS	N.MOH	79.	16.440	34.05	0.0	0.0	0.0	0.0
86 ROTTERDAM PEAK. (A)	COMBUST.	OIL2	N.MOH	12.	18.822	11.76	0.0	0.0	0.0	0.0
87 ROTTERDAM PEAK. (B)	COMBUST.	GAS	N.MOH	98.	18.822	11.76	0.0	0.0	0.0	0.0
88 SHOEMAKER PEAK. (A)	COMBUST.	OIL2	ORANG	7.	21.113	19.97	0.0	0.0	0.0	0.0
89 SHOEMAKER PEAK. (B)	COMBUST.	GAS	ORANG	30.	21.113	19.97	0.0	0.0	0.0	0.0
90 HILLBURN PEAK.	COMBUST.	OIL2	ORANG	37.	23.013	4.13	0.0	0.0	0.0	0.0
91 BEEBEE PEAK.	COMBUST.	OIL2	RG&E	14.	16.570	34.82	0.0	0.0	0.0	0.0
92 STATION 9 PEAK.	COMBUST.	GAS	RG&E	15.	14.420	0.67	0.0	0.0	0.0	0.0
93 INDIAN POINT PEAK.	COMBUST.	OIL2	CONED	17.	33.200	5167.85	0.0	0.0	0.0	0.0
94 SHOREHAM	NUCLEAR	NUCL	LILCO	809.	11.032	6.18	0.0	0.0	0.0	0.0
95 SOMERSET	ST. TURB	COAL	NYSEG	625.	10.500	7.79	0.30	0.0	0.60	0.10
96 NINE MILE PT 2	NUCLEAR	NUCL	N.MOH	1080.	11.032	6.18	0.0	0.0	0.0	0.0

CAPACITY BY PLANT TYPE

PLANT	MW
ST. TURB	18848.
HYDRO	4021.
P. STOR.	0.
NUCLEAR	5483.
COMBUST.	3420.
DIESEL	0.
TOTAL	31772.

FUEL CHARACTERISTICS

NAME	FUEL	PLANT	SULPH FRAC	EST SO2 /MBTU	ASH FRAC	HEAT VAL MBTU	PRICE DOL.	PRICE $/MBTU	FUEL COST $/MWHR	GEN COST $/MWHR
1 GOUDEY	COAL	D101	0.0196	3.3547	0.1850	23.37/TON	30.99/TON	1.33	14.59	17.33
2 GREENRIDGE	COAL	D102	0.0209	3.4906	0.1540	23.95/TON	33.12/TON	1.38	16.20	20.84
3 HICKLING	COAL	D103	0.0084	1.5013	0.2280	22.38/TON	24.37/TON	1.09	15.30	19.82
4 JENNISON	COAL	D104	0.0090	1.6356	0.2370	22.01/TON	26.41/TON	1.20	16.71	20.72
5 MILLIKEN	COAL	D105	0.0185	3.1303	0.1550	23.64/TON	34.65/TON	1.47	13.83	16.14
6 HOMER CITY	COAL	D106	0.0214	3.7266	0.1700	22.97/TON	27.88/TON	1.21	12.56	14.52
7 HUNTLY	COAL	D107	0.0153	2.3749	0.1120	25.77/TON	43.50/TON	1.69	17.99	20.79
8 DUNKIRK	COAL	D108	0.0214	3.3529	0.1080	25.53/TON	36.51/TON	1.43	14.74	17.25
9 RUSSELL	COAL	D109	0.0237	3.7574	0.1200	25.23/TON	37.94/TON	1.50	15.97	20.41
10 BEEBEE 12	COAL	D110	0.0275	4.4552	0.0900	24.69/TON	36.49/TON	1.48	14.40	7.47
11 JAMESTOWN	COAL	D111	0.0222	3.7468	0.1320	23.70/TON	29.74/TON	1.25	18.34	25.53
12 C. HUDSON MISC.	H20	D112	0.0	0.0	0.0	1.00	0.0	0.0	0.0	16.17
13 NYSEG MISC.	H20	D113	0.0	0.0	0.0	1.00	0.0	0.0	0.0	2.00
14 N.MOH 18 SITES	H20	D114	0.0	0.0	0.0	1.00	0.0	0.0	0.0	1.99
15 N.MOH MISC.	H20	D115	0.0	0.0	0.0	1.00	0.0	0.0	0.0	2.25
16 ORANGE & ROCKLAND	H20	D116	0.0	0.0	0.0	1.00	0.0	0.0	0.0	5.67
17 MOSES NIAGARA	H20	D117	0.0	0.0	0.0	1.00	0.0	0.0	0.0	0.32
18 MASSENA	H20	D118	0.0	0.0	0.0	1.00	0.0	0.0	0.0	0.26
19 RG&E MISC.	H20	D119	0.0	0.0	0.0	1.00	0.0	0.0	0.0	2.00
20 INDIAN PT 2	NUCL	D121	0.0	0.0	0.0	63.15/GM	30.19/GM	0.48	5.73	12.54
21 NINE MILE PT 1	NUCL	D122	0.0	0.0	0.0	81.24/GM	71.00/GM	0.87	9.28	13.17
22 FITZPATRICK	NUCL	D123	0.0	0.0	0.0	52.21/GM	11.64/GM	0.22	2.28	10.75
23 INDIAN PT 3	NUCL	D124	0.0	0.0	0.0	55.48/GM	16.03/GM	0.29	3.23	9.27
24 GINNA	NUCL	D125	0.0	0.0	0.0	94.23/GM	50.00/GM	0.53	5.81	10.16
25 ROSETON	OIL6	D126	0.0181	1.8518	0.0	6.24/BBL	22.17/BBL	3.55	35.00	35.92
26 DANSK N.3-4	OIL6	D127	0.0094	0.9684	0.0	6.20/BBL	26.55/BBL	4.28	45.14	47.52
27 DANSK N.1-2	GAS	D128	0.0	0.0	0.0	1.01/KCF	2.64/KCF	2.61	27.46	29.84
28 ARTHUR KILL	OIL6	D129	0.0064	0.6641	0.0	6.15/BBL	30.04/BBL	4.88	52.18	56.33
29 ASTORIA N.4-5	OIL6	D130	0.0029	0.3017	0.0	6.14/BBL	30.36/BBL	4.95	55.65	64.37
30 ASTORIA N.1-3	GAS	D131	0.0	0.0	0.0	1.04/KCF	2.79/KCF	2.67	32.14	40.86
31 BOWLINE (A)	OIL6	D132	0.0050	0.5163	0.0	6.18/BBL	28.14/BBL	4.55	45.84	47.74
32 BOWLINE (B)	GAS	D133	0.0	0.0	0.0	1.03/KCF	2.54/KCF	2.47	24.84	26.75
33 EAST RIVER (A)	OIL6	D134	0.0029	0.3018	0.0	6.14/BBL	30.01/BBL	4.89	65.43	75.41
34 EAST RIVER (B)	GAS	D135	0.0	0.0	0.0	1.04/KCF	2.62/KCF	2.53	33.83	43.81
35 HUDSON AVE.	OIL6	D136	0.0030	0.3128	0.0	6.12/BBL	30.36/BBL	4.96	135.81	210.62
36 RAVENS. N.3	OIL6	D137	0.0058	0.6022	0.0	6.15/BBL	30.24/BBL	4.92	53.05	58.15
37 RAVENS. N.1&2	GAS	D138	0.0	0.0	0.0	1.03/KCF	2.67/KCF	2.59	27.68	32.78
38 WATERSIDE (A)	OIL6	D139	0.0029	0.3018	0.0	6.13/BBL	30.13/BBL	4.91	83.33	103.46
39 WATERSIDE (B)	GAS	D140	0.0	0.0	0.0	1.04/KCF	2.78/KCF	2.66	45.17	65.30
40 59TH STREET	OIL6	D141	0.0029	0.3019	0.0	6.13/BBL	30.30/BBL	4.94	69.21	116.29
41 74TH STREET	OIL6	D142	0.0029	0.3020	0.0	6.13/BBL	30.14/BBL	4.92	99.14	131.41
42 NORTHPORT	OIL6	D143	0.0208	2.1097	0.0	6.29/BBL	22.50/BBL	3.57	36.31	38.50
43 PORT JEFF	OIL6	D144	0.0234	2.3633	0.0	6.32/BBL	22.32/BBL	3.53	37.13	39.20
44 GLENWOOD (A)	OIL6	D145	0.0062	0.6443	0.0	6.14/BBL	31.93/BBL	5.20	62.00	72.61
45 GLENWOOD (B)	GAS	D146	0.0	0.0	0.0	1.04/KCF	3.18/KCF	3.07	36.61	47.22
46 BARRETT (A)	OIL6	D147	0.0032	0.3346	0.0	6.11/BBL	31.10/BBL	5.09	54.46	56.49
47 BARRETT (B)	GAS	D148	0.0	0.0	0.0	1.03/KCF	3.14/KCF	3.03	32.44	34.47
48 FAR ROCKAWAY	OIL6	D149	0.0025	0.2623	0.0	6.08/BBL	31.35/BBL	5.15	61.06	73.41
49 OSWEGO 1-5	OIL6	D150	0.0098	1.0171	0.0	6.15/BBL	28.24/BBL	4.59	51.99	53.76
50 OSWEGO 6	OIL6	D151	0.0098	1.0171	0.0	6.15/BBL	28.24/BBL	4.59	50.17	51.94
51 ALBANY	OIL6	D152	0.0202	2.0719	0.0	6.22/BBL	26.98/BBL	4.33	44.87	46.76
52 LOVETT (A)	OIL6	D153	0.0029	0.3033	0.0	6.10/BBL	30.84/BBL	5.05	56.18	58.91
53 LOVETT (B)	GAS	D154	0.0	0.0	0.0	1.03/KCF	2.53/KCF	2.45	27.29	30.02
54 ASTORIA 6	OIL6	D155	0.0029	0.3017	0.0	6.14/BBL	30.36/BBL	4.95	50.24	52.64
55 BEEBEE 1	OIL6	D156	0.0197	2.0052	0.0	6.27/BBL	26.15/BBL	4.17	40.61	33.68

FUEL CHARACTERISTICS

NAME	FUEL	PLANT	SULPH FRAC	EST SO2 /MBTU	ASH FRAC	HEAT VAL MBTU	PRICE DOL.	PRICE $/MBTU	FUEL COST $/MWHR	GEN COST $/MWHR
56 COXS. PEAK. (A)	OIL2	D157	0.0010	0.0	0.0	5.65/BBL	25.71/BBL	4.55	61.42	136.39
57 COXS. PEAK. (B)	GAS	D158	0.0	0.0	0.0	1.01/KCF	2.75/KCF	2.71	36.64	111.61
58 S. CAIRO PEAK.	OIL2	D159	0.0050	0.0	0.0	5.67/BBL	23.05/BBL	4.07	58.29	77.13
59 ARTHUR KILL PEAK.	OIL2	D160	0.0030	0.0	0.0	5.77/BBL	23.73/BBL	4.12	74.55	230.24
60 ASTORIA PEAK. (A)	OIL2	D161	0.0020	0.0	0.0	5.71/BBL	21.56/BBL	3.77	61.00	86.90
61 ASTORIA PEAK. (B)	GAS	D162	0.0	0.0	0.0	1.03/KCF	2.99/KCF	2.91	47.02	72.92
62 GOWANUS PEAK.	OIL2	D163	0.0020	0.0	0.0	5.78/BBL	26.86/BBL	4.64	78.45	157.36
63 HUDSON AVE. PEAK.	OIL2	D164	0.0030	0.0	0.0	5.71/BBL	23.90/BBL	4.18	74.95	446.80
64 BUCHANAN PEAK.	OIL2	D165	0.0020	0.0	0.0	5.82/BBL	21.61/BBL	3.71	70.95	224.70
65 KENT GT. PEAK.	OIL2	D166	0.0003	0.0	0.0	5.65/BBL	24.86/BBL	4.40	77.87	215.93
66 NARROWS PEAK. (A)	OIL2	D167	0.0020	0.0	0.0	5.78/BBL	33.31/BBL	5.77	105.68	180.15
67 NARROWS PEAK. (B)	GAS	D168	0.0	0.0	0.0	1.03/KCF	2.73/KCF	2.64	48.38	122.85
68 RAVENS. PEAK. (A)	OIL2	D169	0.0020	0.0	0.0	5.65/BBL	22.95/BBL	4.06	64.97	109.00
69 RAVENS. PEAK. (B)	GAS	D170	0.0	0.0	0.0	1.03/KCF	3.04/KCF	2.95	47.28	91.31
70 WATERSIDE PEAK.	OIL2	D171	0.0014	0.0	0.0	5.65/BBL	19.54/BBL	3.46	64.54	532.27
71 59TH STREET PEAK.	OIL2	D172	0.0029	0.0	0.0	5.63/BBL	24.26/BBL	4.31	77.84	143.74
72 74TH STREET PEAK.	OIL2	D173	0.0029	0.0	0.0	5.61/BBL	24.83/BBL	4.43	99.13	251.72
73 NORTHPORT 6T PEAK.	OIL2	D174	0.0050	0.0	0.0	5.83/BBL	22.35/BBL	3.84	127.28	293.10
74 PORT JEFF PEAK.	OIL2	D175	0.0050	0.0	0.0	5.85/BBL	22.55/BBL	3.85	100.43	162.78
75 GLENNWOOD PEAK.	OIL2	D176	0.0013	0.0	0.0	5.74/BBL	31.93/BBL	5.56	82.54	106.91
76 BARRETT PEAK. (A)	OIL2	D177	0.0032	0.0	0.0	5.77/BBL	23.05/BBL	4.00	70.92	109.41
77 BARRETT PEAK. (B)	GAS	D178	0.0	0.0	0.0	1.03/KCF	3.66/KCF	3.55	63.06	101.55
78 SHOREHAM PEAK.	OIL2	D179	0.0015	0.0	0.0	5.82/BBL	35.32/BBL	6.06	99.25	118.24
79 W. BABYLON PEAK.	OIL2	D180	0.0007	0.0	0.0	5.82/BBL	32.12/BBL	5.52	115.01	145.33
80 SOUTHOLD PEAK.	OIL2	D181	0.0050	0.0	0.0	5.84/BBL	24.94/BBL	4.27	111.36	245.48
81 S. HAMPTON PEAK.	OIL2	D182	0.0030	0.0	0.0	5.84/BBL	20.75/BBL	3.56	60.82	265.24
82 E. HAMPTON PEAK.	OIL2	D183	0.0015	0.0	0.0	5.84/BBL	28.25/BBL	4.83	81.19	106.55
83 HOLBROOK PEAK.	OIL2	D184	0.0015	0.0	0.0	5.82/BBL	34.12/BBL	5.86	87.10	102.26
84 ALBANY PEAK. (A)	OIL2	D185	0.0020	0.0	0.0	5.74/BBL	19.70/BBL	3.43	56.46	90.51
85 ALBANY PEAK. (B)	GAS	D186	0.0	0.0	0.0	1.00/KCF	2.74/KCF	2.74	45.00	79.05
86 ROTTERDAM PEAK. (A)	OIL2	D187	0.0030	0.0	0.0	5.77/BBL	33.26/BBL	5.76	108.40	120.16
87 ROTTERDAM PEAK. (B)	GAS	D188	0.0	0.0	0.0	1.03/KCF	2.67/KCF	2.59	48.79	60.55
88 SHOEMAKER PEAK. (A)	OIL2	D189	0.0002	0.0	0.0	5.27/BBL	37.82/BBL	7.18	151.52	171.49
89 SHOEMAKER PEAK. (B)	GAS	D190	0.0	0.0	0.0	1.02/KCF	2.71/KCF	2.65	55.98	75.95
90 HILLBURN PEAK.	OIL2	D191	0.0002	0.0	0.0	5.27/BBL	36.64/BBL	6.95	159.97	164.10
91 BEEBEE PEAK.	OIL2	D192	0.0050	0.0	0.0	6.88/BBL	22.41/BBL	3.26	53.97	88.79
92 STATION 9 PEAK.	GAS	D193	0.0	0.0	0.0	1.02/KCF	2.68/KCF	2.62	37.74	38.41
93 INDIAN POINT PEAK.	OIL2	D194	0.0030	0.0	0.0	6.13/BBL	30.00/BBL	4.90	162.59	5330.43
94 SHOREHAM	NUCL	D195	0.0	0.0	0.0	65.99/GM	32.16/GM	0.49	5.38	11.56
95 SOMERSET	COAL	D196	0.0024	0.3805	0.1200	25.23/TON	37.94/TON	1.50	15.79	23.58
96 NINE MILE PT 2	NUCL	D197	0.0	0.0	0.0	65.99/GM	32.16/GM	0.49	5.38	11.56

CAPACITY BY FUEL TYPE

FUEL	MW
COAL	4155.
OIL6	11692.
GAS	4047.
H20	4021.
NUCL	5483.
OIL2	2374.
TOTAL	31772.

Appendix B.

I. Financial Data

II. Operating Data

BALANCE SHEET

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ASSETS:										
ELEC UTIL PLT	14329.898	14519.059	14728.801	14961.367	18653.801	20232.211	20232.211	24871.902	24871.902	24871.902
(ACCUM DEPR)	4094.255	4509.082	4929.902	5357.363	5906.680	6501.086	7095.496	7844.570	8593.637	9342.719
NET ELEC PLT	10235.641	10009.977	9798.898	9604.004	12747.121	13731.125	13136.715	17027.332	16278.266	15529.184
CWIP	3680.601	4582.250	6154.070	7763.930	5115.332	4135.492	4639.691	0.0	0.0	0.0
TOT ELEC PL	13916.238	14592.227	15952.969	17367.934	17862.453	17866.617	17776.406	17027.332	16278.266	15529.184
OTHER ASSETS	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998
CURR. ASSETS	2011.000	2131.661	2259.560	2395.134	2538.841	2691.171	2852.642	3023.799	3205.227	3397.540
TOTAL ASSETS	19505.234	20301.883	21790.523	23341.062	23979.289	24135.781	24207.043	23629.125	23061.488	22504.719
TOTAL CAPITALIZATION, LIABILITIES, CREDITS:										
PRIOR COM EQ	3849.500	4188.898	4738.023	5045.207	5246.379	5527.855	5448.691	5160.703	4924.797	4362.402
NEW COM EQ	339.400	549.125	307.184	201.172	281.477	-79.164	-287.988	-235.906	-562.395	-628.363
RETAINED EARN	2570.330	2630.284	2793.769	3099.915	2849.047	2794.894	2993.518	2667.563	2792.240	3004.546
TOT COM EQ	6759.227	7368.305	7838.973	8346.293	8376.902	8243.582	8154.219	7592.359	7154.641	6738.582
PRIOR PREF EQ	1898.600	2024.200	2138.046	2274.618	2421.826	2430.708	2392.024	2366.094	2203.059	2076.047
NEW PREF EQ	125.600	113.846	136.573	147.208	8.882	-38.685	-25.930	-163.035	-127.012	-120.726
TOT PREF EQ	2024.200	2138.046	2274.618	2421.826	2430.708	2392.024	2366.094	2203.059	2076.047	1955.321
LONG TERM DT	7740.398	8163.445	8684.906	9246.973	9280.887	9111.840	8922.508	8411.680	7926.723	7465.770
CURR LIABILS	1623.000	1720.381	1823.603	1933.019	2049.000	2171.940	2302.256	2440.391	2586.814	2742.022
ACCUM DEF ITC	291.160	296.335	301.062	305.342	515.892	603.904	581.720	801.389	770.865	740.342
AC DEF INC TX	328.731	615.372	867.365	1087.617	1325.901	1612.490	1880.244	2180.248	2546.401	2862.687
TOT LIABILS	19505.234	20301.875	21790.520	23341.059	23979.285	24135.773	24207.035	23629.121	23061.484	22504.715

FIRST YEAR ADJUSTMENT TO LIABILITIES 738.523

BALANCE SHEET

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ASSETS:										
ELEC UTIL PLT	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902
(ACCUM DEPR)	10091.781	10840.855	11589.918	12338.996	13088.062	13837.137	14586.211	15335.277	16084.348	16833.418
NET ELEC PLT	14780.121	14031.047	13281.984	12532.906	11783.840	11034.766	10285.691	9536.625	8787.555	8038.484
CWIP	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOT ELEC PL	14780.121	14031.047	13281.984	12532.906	11783.840	11034.766	10285.691	9536.625	8787.555	8038.484
OTHER ASSETS	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998	3577.998
CURR. ASSETS	3601.391	3817.476	4046.523	4289.312	4546.672	4819.473	5108.641	5415.160	5740.066	6084.473
TOTAL ASSETS	21959.508	21426.516	20906.500	20400.215	19908.508	19432.234	18972.328	18529.781	18105.617	17700.953
TOTAL CAPITALIZATION, LIABILITIES, CREDITS:										
PRIOR COM EQ	3734.039	3175.523	2720.633	2364.516	2097.934	1944.297	1848.332	1793.191	1839.477	1961.745
NEW COM EQ	-558.516	-454.891	-356.117	-266.582	-153.637	-95.965	-55.141	46.285	122.268	0.0
RETAINED EARN	3172.180	3256.205	3254.523	3176.440	3036.567	2852.288	2640.147	2411.258	1972.704	1719.623
TOT COM EQ	6347.703	5976.836	5619.039	5274.371	4980.863	4700.617	4433.336	4250.734	3934.448	3681.368
PRIOR PREF EQ	1955.321	1841.900	1734.286	1630.465	1530.454	1445.287	1363.969	1286.412	1233.427	1141.650
NEW PREF EQ	-113.420	-107.615	-103.820	-100.012	-85.167	-81.318	-77.557	-52.986	-91.776	0.0
TOT PREF EQ	1841.900	1734.286	1630.465	1530.454	1445.287	1363.969	1286.412	1233.427	1141.650	1141.650
LONG TERM DT	7032.707	6621.816	6225.414	5843.551	5518.367	5207.879	4911.754	4542.750	4359.027	4033.365
CURR LIABILS	2906.543	3080.937	3265.792	3461.739	3669.445	3889.610	4122.984	4370.367	4632.586	4910.543
ACCUM DEF ITC	709.818	679.295	648.772	618.248	587.724	557.201	526.677	496.154	465.630	435.107
AC DEF INC TX	3120.840	3333.351	3517.022	3671.854	3706.825	3712.956	3691.162	3636.351	3572.274	3498.929
TOT LIABILS	21959.500	21426.512	20906.496	20400.211	19908.504	19432.227	18972.320	18529.777	18105.613	17700.953

INCOME STATEMENT

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
ELEC OPER REV	6616.270	7240.648	7268.020	7528.187	7691.383	8482.305	9101.531	9452.742	10361.387	10792.324
OTHER OPER REV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPER REV	6616.270	7240.648	7268.020	7528.187	7691.383	8482.305	9101.531	9452.742	10361.387	10792.324
DIR ELEC OP EXP:										
PURCH POWER	295.625	417.608	616.356	745.835	867.549	1161.730	1297.654	1368.885	1542.097	1611.719
FUEL,COAL	292.356	323.294	342.053	453.828	470.941	583.780	625.030	638.084	681.881	731.441
FUEL,OIL	1553.800	1891.352	1730.147	1517.726	1400.204	1201.933	1261.519	1235.673	1282.828	1358.477
FUEL,NAT. GAS	411.273	504.639	468.870	515.610	559.418	518.329	535.355	396.852	404.654	448.009
FUEL,NUCLEAR	90.053	84.864	78.729	84.505	113.206	121.476	130.347	176.877	189.748	203.552
FUEL,OTHER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MAINT	386.094	395.102	362.800	359.706	394.102	427.550	446.698	492.128	518.766	548.932
DEPRECIATION	409.426	414.830	420.823	427.468	549.321	594.418	594.418	749.074	749.074	749.074
OPER TAX EXP:										
INC TAX PAID	167.805	165.828	129.018	210.248	122.033	313.716	502.688	513.628	743.184	879.642
INC TAX DEF	328.731	286.641	251.993	220.252	238.284	286.589	267.755	300.003	366.153	316.286
INC TAX ADJ	41.224	66.354	121.882	111.827	48.762	17.344	4.397	0.0	0.0	0.0
INC TX REP	537.760	518.822	502.893	542.327	409.079	617.648	774.840	813.631	1109.336	1195.928
GROSS REC TAX	49.622	54.305	54.510	56.461	57.685	63.617	68.261	70.896	77.710	80.942
NON-INCOME TAX	564.188	551.749	539.012	525.979	659.079	704.338	673.351	814.296	777.380	740.465
ADMIN, OTH EXP	592.942	629.153	666.508	706.874	752.147	793.403	835.737	883.818	929.549	981.969
TOTAL OPER EXP	5183.137	5785.711	5782.691	5936.309	6232.723	6788.215	7243.195	7640.199	8263.012	8650.492
AFUDC-EQUITY	261.849	325.995	437.819	552.349	363.919	294.211	330.081	0.0	0.0	0.0
INCOME TX CRED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOT OTHER INC	261.849	325.995	437.819	552.349	363.919	294.211	330.081	0.0	0.0	0.0
L TERM INT EXP	883.740	928.848	979.613	1042.188	1109.635	1113.704	1093.418	1070.698	1009.398	951.203
OTHER INTEREST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(AFUDC-DEBT)	99.374	123.718	166.157	209.622	138.111	111.656	125.269	0.0	0.0	0.0
TOTAL INT EXP	784.366	805.129	813.456	832.566	971.524	1002.048	968.149	1070.698	1009.398	951.203
NET INCOME	910.616	975.803	1109.691	1311.662	851.055	986.252	1220.268	741.845	1088.977	1190.629

INCOME STATEMENT

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
ELEC OPER REV	11075.398	11350.941	11678.289	12082.465	12576.719	13181.598	13890.875	14698.141	15606.012	16896.184
OTHER OPER REV	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL OPER REV	11075.398	11350.941	11678.289	12082.465	12576.719	13181.598	13890.875	14698.141	15606.012	16896.184
DIR ELEC OP EXP:										
PURCH POWER	1650.695	1681.081	1713.612	1753.583	1804.125	1869.296	1948.737	2041.775	1317.129	1418.787
FUEL,COAL	786.177	846.355	912.181	983.556	1060.332	1142.480	1230.313	1323.855	1463.667	1568.973
FUEL,OIL	1498.706	1700.985	1967.213	2390.107	2700.844	3133.176	3901.216	4475.484	5892.121	6913.660
FUEL,NAT. GAS	492.394	544.990	603.122	583.260	725.407	816.821	657.026	723.103	1105.109	898.431
FUEL,NUCLEAR	218.354	234.228	251.250	269.503	289.076	310.063	332.567	356.698	382.570	410.312
FUEL,OTHER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MAINT	582.610	619.632	660.000	695.876	752.546	806.223	838.685	899.111	1032.542	1087.263
DEPRECIATION	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074
OPER TAX EXP:										
INC TAX PAID	931.049	928.125	889.473	840.936	880.030	831.457	787.054	751.705	527.530	590.845
INC TAX DEF	258.153	212.511	183.672	154.832	34.971	6.132	-21.794	-54.810	-64.077	-73.344
INC TAX ADJ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INC TX REP	1189.202	1140.636	1073.144	995.768	915.001	837.589	765.260	696.894	463.453	517.500
GROSS REC TAX	83.065	85.132	87.587	90.618	94.325	98.862	104.182	110.236	117.045	126.721
NON-INCOME TAX	703.550	666.634	629.719	592.803	555.887	518.971	482.056	445.141	408.226	371.310
ADMIN, OTH EXP	1042.967	1112.569	1190.300	1275.629	1368.050	1466.889	1571.772	1682.572	1799.202	1916.875
TOTAL OPER EXP	8996.773	9381.297	9837.180	10379.762	11014.652	11749.426	12580.871	13503.926	14730.117	15978.891
AFUDC-EQUITY	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
INCOME TX CRED	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOT OTHER INC	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
L TERM INT EXP	895.888	843.921	794.614	747.045	701.221	662.199	624.941	589.406	545.125	523.079
OTHER INTEREST	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(AFUDC-DEBT)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL INT EXP	895.888	843.921	794.614	747.045	701.221	662.199	624.941	589.406	545.125	523.079
NET INCOME	1182.737	1125.724	1046.496	955.658	860.845	769.972	685.063	604.809	330.769	394.214

RETAINED EARNINGS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
JANUARY 1 BAL	2554.700	2570.330	2630.284	2793.769	3099.915	2849.047	2794.894	2993.518	2667.563	2792.240
NET INCOME	910.616	975.803	1109.691	1311.662	851.055	986.252	1220.268	741.845	1088.977	1190.629
(PREF DIVIDS)	256.311	273.266	288.635	307.072	326.945	328.144	322.921	319.420	297.410	280.263
(COM DIVIDS)	638.675	642.583	657.571	698.442	774.979	712.262	698.723	748.379	666.891	698.060
DECEMBR 31 BAL	2570.330	2630.284	2793.769	3099.915	2849.047	2794.894	2993.518	2667.563	2792.240	3004.546

RETAINED EARNINGS

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
JANUARY 1 BAL	3004.546	3172.180	3256.205	3254.523	3176.440	3036.567	2852.288	2640.147	2411.258	1972.704
NET INCOME	1182.737	1125.724	1046.496	955.658	860.845	769.972	685.063	604.809	330.769	394.214
(PREF DIVIDS)	263.965	248.653	234.125	220.109	206.607	195.110	184.132	173.662	166.509	154.119
(COM DIVIDS)	751.136	793.045	814.051	813.631	794.110	759.142	713.072	660.037	602.814	493.176
DECEMBR 31 BAL	3172.180	3256.205	3254.523	3176.440	3036.567	2852.288	2640.147	2411.258	1972.704	1719.623

FEDERAL INCOME TAX, CURRENT

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
TAXABLE INCOME										
TOT OPER REV	6616.270	7240.648	7268.020	7528.187	7691.383	8482.305	9101.531	9452.742	10361.387	10792.324
(DIR OP EXPS)	3029.201	3616.859	3598.955	3677.209	3805.419	4014.797	4296.602	4308.496	4619.973	4902.125
(ACCEL DEPR)	1042.174	954.997	884.000	819.319	936.130	1072.758	1031.815	1187.967	1331.770	1223.364
(GR REC TAX)	49.622	54.305	54.510	56.461	57.685	63.617	68.261	70.896	77.710	80.942
(PROP TAX)	564.188	551.749	539.012	525.979	659.079	704.338	673.351	814.296	777.380	740.465
(ST INC TAX)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(ADM,OTH EXP)	592.942	629.153	666.508	706.874	752.147	793.403	835.737	883.818	929.549	981.969
(INTERST EXP)	883.740	928.848	979.613	1042.188	1109.635	1113.704	1093.418	1070.698	1009.398	951.203
TOTAL	454.410	504.742	545.434	700.164	371.293	719.695	1102.359	1116.582	1615.617	1912.266
(INV TX CRED)	41.224	66.354	121.882	111.827	48.762	17.344	4.397	0.0	0.0	0.0
TOTAL TAX PD	167.805	165.828	129.018	210.248	122.033	313.716	502.688	513.628	743.184	879.642

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
TAXABLE INCOME										
TOT OPER REV	11075.398	11350.941	11678.289	12082.465	12576.719	13181.598	13890.875	14698.141	15606.012	16896.184
(DIR OP EXPS)	5228.930	5627.266	6107.371	6675.879	7332.324	8078.055	8908.539	9820.020	11193.133	12297.418
(ACCEL DEPR)	1096.989	997.767	935.072	872.377	611.811	549.116	488.407	416.633	396.487	376.342
(GR REC TAX)	83.065	85.132	87.587	90.618	94.325	98.862	104.182	110.236	117.045	126.721
(PROP TAX)	703.550	666.634	629.719	592.803	555.887	518.971	482.056	445.141	408.226	371.310
(ST INC TAX)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
(ADM,OTH EXP)	1042.967	1112.569	1190.300	1275.629	1368.050	1466.889	1571.772	1682.572	1799.202	1916.875
(INTERST EXP)	895.888	843.921	794.614	747.045	701.221	662.199	624.941	589.406	545.125	523.079
TOTAL	2024.020	2017.664	1933.637	1828.121	1913.109	1807.516	1710.988	1634.141	1146.805	1284.445
(INV TX CRED)	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
TOTAL TAX PD	931.049	928.125	889.473	840.936	880.030	831.457	787.054	751.705	527.530	590.845

FUNDS PROVIDED AND APPLIED

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
FUNDS PROVIDED										
NET INCOME	910.616	975.803	1109.691	1311.662	851.055	986.252	1220.268	741.845	1088.977	1190.629
DEPRECIATION	409.426	414.830	420.823	427.468	549.321	594.418	594.418	749.074	749.074	749.074
DEFERRED TAX	328.731	286.641	251.993	220.252	238.284	286.589	267.755	300.003	366.153	316.286
DEFERRED ITC	0.0	5.175	4.727	4.280	210.550	88.012	-22.184	219.669	-30.524	-30.523
LESS										
AFUDC-EQ	261.849	325.995	437.819	552.349	363.919	294.211	330.081	0.0	0.0	0.0
AFUDC-DEBT	99.374	123.718	166.157	209.622	138.111	111.656	125.269	0.0	0.0	0.0
NEW LT DEBT	375.900	530.477	641.785	696.832	184.852	0.0	0.0	0.0	0.0	0.0
NEW COM STOCK	339.400	549.125	307.184	201.172	281.477	-79.164	-287.988	-235.906	-562.395	-628.363
NEW PREF STCK	125.600	113.846	136.573	147.208	8.882	-38.685	-25.930	-163.035	-127.012	-120.726
OTHER,MISC	-835.165	-738.526	0.005	-0.010	-0.005	-0.010	-0.005	-0.003	-0.011	0.005
TOT FDS PROV	1293.284	1687.657	2268.805	2246.892	1822.385	1431.545	1290.985	1611.647	1484.262	1476.381
FUNDS APPLIED:										
ADDNS,UTIL PL	759.522	1090.812	1781.575	1842.428	1043.829	598.573	504.208	0.0	0.0	0.0
ADDNS,POL CON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LESS										
AFUDC EQ	261.849	325.995	437.819	552.349	363.919	294.211	330.081	0.0	0.0	0.0
AFUDC DEBT	99.374	123.718	166.157	209.622	138.111	111.656	125.269	0.0	0.0	0.0
ADDNS,COAL FU										
ADDNS,NUC FU										
DEBT RETIREMT	0.0	107.429	120.324	134.762	150.936	169.044	189.329	510.825	484.957	460.953
PREF STK DIVS	256.311	273.266	288.635	307.072	326.945	328.144	322.921	319.420	297.410	280.263
COM STK DIVS	638.675	642.583	657.571	698.442	774.979	712.262	698.723	748.379	666.891	698.060
NOTES RETIRMT										
OTH EXPS,INV										
CHG,WORK CAP	0.0	23.280	24.677	26.157	27.727	29.390	31.154	33.023	35.005	37.105
TOT FDS APPL	1293.284	1687.657	2268.805	2246.892	1822.385	1431.545	1290.985	1611.647	1484.262	1476.381

FUNDS PROVIDED AND APPLIED

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
FUNDS PROVIDED										
NET INCOME	1182.737	1125.724	1046.496	955.658	860.845	769.972	685.063	604.809	330.769	394.214
DEPRECIATION	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074
DEFERRED TAX	258.153	212.511	183.672	154.832	34.971	6.132	-21.794	-54.810	-64.077	-73.344
DEFERRED ITC	-30.524	-30.524	-30.523	-30.524	-30.524	-30.523	-30.523	-30.524	-30.523	-30.523
LESS										
AFUDC-EQ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC-DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
NEW LT DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	553.894	500.469
NEW COM STOCK	-558.516	-454.891	-356.117	-266.582	-153.637	-95.965	-55.141	46.285	122.268	0.0
NEW PREF STCK	-113.420	-107.615	-103.820	-100.012	-85.167	-81.318	-77.557	-52.986	-91.776	0.0
OTHER,MISC	-0.010	-0.001	-0.011	-0.001	-0.008	0.003	-0.003	-0.013	-0.001	-0.014
TOT FDS PROV	1487.494	1494.280	1488.770	1462.445	1375.554	1317.375	1249.119	1261.835	1569.627	1539.874
FUNDS APPLIED:										
ADDNS,UTIL PL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ADDNS,POL CON	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
LESS										
AFUDC EQ	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
AFUDC DEBT	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
ADDNS,COAL FU										
ADDNS,NUC FU										
DEBT RETIREMT	433.062	410.891	396.402	381.863	325.184	310.488	296.122	369.000	737.617	826.131
PREF STK DIVS	263.965	248.653	234.125	220.109	206.607	195.110	184.132	173.662	166.509	154.119
COM STK DIVS	751.136	793.045	814.051	813.631	794.110	759.142	713.072	660.037	602.814	493.176
NOTES RETIRMT										
OTH EXPS,INV										
CHG,WORK CAP	39.331	41.691	44.192	46.842	49.654	52.635	55.794	59.137	62.688	66.449
TOT FDS APPL	1487.494	1494.280	1488.770	1462.445	1375.554	1317.375	1249.119	1261.835	1569.627	1539.874

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
GRSS RATE BASE	14329.898	14519.059	14728.801	14961.367	18653.801	20232.211	20232.211	24871.902	24871.902	24871.902
RATE BASE ADJS										
CUM DEPREC	4094.255	4509.082	4929.902	5357.363	5906.680	6501.086	7095.496	7844.570	8593.637	9342.719
CUM DEF ITC	202.546	206.146	209.435	212.412	358.881	431.277	415.516	593.237	570.805	548.372
CUM DEF TAXES	178.063	329.265	461.289	576.225	706.229	893.960	1079.557	1273.600	1553.981	1803.513
TOTAL	4474.859	5044.488	5600.621	6145.996	6971.765	7826.316	8590.566	9711.402	10718.422	11694.602
NET RATE BASE	9855.027	9474.562	9128.172	8815.363	11682.008	12405.887	11641.637	15160.492	14153.477	13177.293
REVENUE ALLOWANCE										
FD INC TX ALL	452.979	460.220	468.431	477.735	734.785	820.111	792.515	1109.823	1063.275	1017.593
ST INC TX ALL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER TAX	564.188	551.749	539.012	525.979	659.079	704.338	673.351	814.296	777.380	740.465
RETURN-DEBT	546.363	525.270	506.065	488.723	647.649	687.781	645.411	840.495	784.666	730.546
RETURN-COMMON	616.432	592.634	570.967	551.401	730.709	775.988	728.184	948.288	885.300	824.239
RETURN-PREF	160.982	154.767	149.108	143.998	190.825	202.649	190.165	247.645	231.195	215.249
DEPRECIATION	409.426	414.830	420.823	427.468	549.321	594.418	594.418	749.074	749.074	749.074
PURCH POWER	295.625	417.608	616.356	745.835	867.549	1161.730	1297.654	1368.885	1542.097	1611.719
FUEL-COAL	292.356	323.294	342.053	453.828	470.941	583.780	625.030	638.084	681.881	731.441
FUEL-OIL	1553.800	1891.352	1730.147	1517.726	1400.204	1201.933	1261.519	1235.673	1282.828	1358.477
FUEL-NAT. GAS	411.273	504.639	468.870	515.610	559.418	518.329	535.355	396.852	404.654	448.009
FUEL-NUCLEAR	90.053	84.864	78.729	84.505	113.206	121.476	130.347	176.877	189.748	203.552
FUEL-OTHER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MAINT EXPENSE	386.094	395.102	362.800	359.706	394.102	427.550	446.698	492.128	518.766	548.932
ADMIN,OTH EXP	592.942	629.153	666.508	706.874	752.147	793.403	835.737	883.818	929.549	981.969
TOTAL	6398.309	6973.598	6947.879	7027.723	8102.602	8628.277	8791.832	9942.023	10081.062	10202.398

REGULATORY ECONOMICS

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
GRSS RATE BASE	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902	24871.902
RATE BASE ADJS										
CUM DEPREC	10091.781	10840.855	11589.918	12338.996	13088.062	13837.137	14586.211	15335.277	16084.348	16833.418
CUM DEF ITC	525.940	503.508	481.075	458.643	436.210	413.777	391.345	368.913	346.480	324.048
CUM DEF TAXES	2012.829	2193.380	2360.991	2514.742	2562.722	2593.545	2607.362	2598.199	2585.766	2566.578
TOTAL	12630.547	13537.738	14431.980	15312.379	16086.988	16844.453	17584.914	18302.387	19016.590	19724.043
NET RATE BASE	12241.348	11334.156	10439.914	9559.516	8784.906	8027.441	7286.980	6569.508	5855.309	5147.852
REVENUE ALLOWANCE										
FD INC TX ALL	973.476	930.218	886.819	843.397	806.184	769.275	732.709	696.934	654.977	607.437
ST INC TX ALL	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
OTHER TAX	703.550	666.634	629.719	592.803	555.887	518.971	482.056	445.141	408.226	371.310
RETURN-DEBT	678.657	628.362	578.785	529.976	487.032	445.038	403.987	364.210	324.615	285.394
RETURN-COMMON	765.696	708.951	653.016	597.948	549.496	502.116	455.801	410.922	366.249	321.998
RETURN-PREF	199.960	185.141	170.533	156.152	143.499	131.126	119.030	107.310	95.644	84.088
DEPRECIATION	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074	749.074
PURCH POWER	1650.695	1681.081	1713.612	1753.583	1804.125	1869.296	1948.737	2041.775	1317.129	1418.787
FUEL-COAL	786.177	846.355	912.181	983.556	1060.332	1142.480	1230.313	1323.855	1465.667	1568.973
FUEL-OIL	1498.706	1700.985	1967.213	2390.107	2700.844	3133.176	3901.216	4475.484	5892.121	6913.660
FUEL-NAT. GAS	492.394	544.990	603.122	583.260	725.407	816.821	657.026	723.103	1105.109	898.431
FUEL-NUCLEAR	218.354	234.228	251.250	269.503	289.076	310.063	332.567	356.698	382.570	410.312
FUEL-OTHER	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0	0.0
MAINT EXPENSE	582.610	619.632	660.000	695.876	752.546	806.223	838.685	899.111	1032.542	1087.263
ADMIN,OTH EXP	1042.967	1112.569	1190.300	1275.629	1368.050	1466.889	1571.772	1682.572	1799.202	1916.875
TOTAL	10384.180	10651.164	11010.012	11467.098	12040.094	12711.805	13477.312	14333.984	15654.246	16700.941

INTEREST COVERAGE AND PROFITABILITY RATIOS

INTEREST COVERAGE RATIOS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
OPER INCOME	1.622	1.566	1.516	1.527	1.315	1.521	1.700	1.693	2.079	2.252
OP INC+INC TX	2.230	2.125	2.030	2.048	1.683	2.076	2.408	2.453	3.178	3.509
OPER INCOME + INC TX&DEPREC	2.693	2.572	2.459	2.458	2.178	2.609	2.952	3.152	3.920	4.296
INC BEFORE INT	1.918	1.917	1.963	2.057	1.643	1.785	2.001	1.693	2.079	2.252

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
OPER INCOME	2.320	2.334	2.317	2.279	2.228	2.163	2.096	2.026	1.607	1.754
OP INC+INC TX	3.648	3.686	3.668	3.612	3.533	3.428	3.321	3.209	2.457	2.743
OPER INCOME + INC TX&DEPREC	4.484	4.573	4.610	4.615	4.601	4.559	4.519	4.479	3.831	4.175
INC BEFORE INT	2.320	2.334	2.317	2.279	2.228	2.163	2.096	2.026	1.607	1.754

PROFITABILITY RATIOS

	1980	1981	1982	1983	1984	1985	1986	1987	1988	1989
NET INCOME DIV BY EQUITY	0.104	0.103	0.110	0.122	0.079	0.093	0.116	0.076	0.118	0.137
ADJ NET INCOME DIV BY EQUITY	0.100	0.085	0.075	0.072	0.054	0.082	0.098	0.106	0.158	0.173
PRE INT NET INC DIV BY RBASE	0.166	0.178	0.196	0.223	0.143	0.145	0.167	0.106	0.129	0.138
ADJ PRE INT NET INC DIV BY RBASE	0.162	0.162	0.160	0.167	0.122	0.136	0.152	0.124	0.151	0.158

	1990	1991	1992	1993	1994	1995	1996	1997	1998	1999
NET INCOME DIV BY EQUITY	0.144	0.146	0.144	0.140	0.134	0.127	0.120	0.110	0.065	0.082
ADJ NET INCOME DIV BY EQUITY	0.176	0.174	0.170	0.163	0.139	0.128	0.116	0.100	0.053	0.067
PRE INT NET INC DIV BY RBASE	0.141	0.140	0.139	0.136	0.133	0.130	0.127	0.125	0.100	0.114
ADJ PRE INT NET INC DIV BY RBASE	0.158	0.156	0.152	0.148	0.136	0.130	0.125	0.119	0.092	0.105

CURRENT DEMAND

YEAR	QUANTITY DEMANDED BILLION KWH	PEAK LOAD MW	AV. PRICE CHARGED $/THOUS.KWH	CPI (=INFF) 1980 = 100	REAL PRICE IN 1980 $ $/THOUS.KWH
1980	106.	20873.	62.	100.	62.
1981	106.	20583.	68.	106.	64.
1982	106.	19985.	69.	112.	61.
1983	106.	19658.	71.	119.	60.
1984	106.	19405.	72.	126.	57.
1985	106.	18789.	80.	134.	60.
1986	105.	18509.	87.	142.	61.
1987	105.	18372.	90.	150.	60.
1988	104.	18108.	99.	159.	62.
1989	104.	17997.	104.	169.	62.
1990	104.	18004.	106.	179.	59.
1991	105.	18107.	108.	190.	57.
1992	106.	18280.	111.	201.	55.
1993	107.	18497.	113.	213.	53.
1994	108.	18739.	116.	226.	51.
1995	109.	18986.	121.	240.	50.
1996	110.	19227.	126.	254.	49.
1997	112.	19456.	132.	269.	49.
1998	113.	20732.	139.	285.	49.
1999	113.	20869.	149.	303.	49.

REVENUE RECEIVED AND TOTAL FUEL COST

YEAR	FUEL COST MILLION $	FUEL COST IN 1980 $ MILLION $	REVENUE RECEIVED MILLION $	CPI (=INFF) 1980 = 100	REV. REC. IN 1980 $ MILLION $
1980	2347.	2347.	6616.	100.	6616.
1981	2804.	2645.	7241.	106.	6831.
1982	2620.	2332.	7268.	112.	6469.
1983	2572.	2159.	7528.	119.	6321.
1984	2544.	2015.	7691.	126.	6092.
1985	2426.	1812.	8482.	134.	6338.
1986	2552.	1799.	9102.	142.	6416.
1987	2447.	1628.	9453.	150.	6287.
1988	2559.	1606.	10361.	159.	6501.
1989	2741.	1623.	10792.	169.	6388.
1990	2996.	1673.	11075.	179.	6184.
1991	3327.	1752.	11351.	190.	5980.
1992	3734.	1856.	11678.	201.	5804.
1993	4226.	1982.	12082.	213.	5665.
1994	4776.	2112.	12577.	226.	5563.
1995	5403.	2254.	13182.	240.	5500.
1996	6121.	2410.	13891.	254.	5468.
1997	6879.	2555.	14698.	269.	5458.
1998	8843.	3098.	15606.	285.	5467.
1999	9791.	3236.	16896.	303.	5584.

DISPATCH (BILLION KWH)

YEAR	PURCHASED POWER	STATE GENER. OF POWER	REQUIRED GENERATION	TOTAL SALES	LOSSES
1980	5.	114.	119.	106.	13.
1981	6.	113.	119.	106.	13.
1982	9.	110.	119.	106.	13.
1983	11.	108.	119.	106.	13.
1984	12.	107.	119.	106.	13.
1985	15.	104.	119.	106.	13.
1986	15.	103.	118.	105.	13.
1987	15.	103.	118.	105.	13.
1988	16.	101.	117.	104.	13.
1989	16.	101.	117.	104.	13.
1990	16.	101.	117.	104.	13.
1991	16.	102.	117.	105.	13.
1992	16.	103.	119.	106.	13.
1993	16.	104.	120.	107.	13.
1994	16.	106.	121.	108.	13.
1995	16.	107.	123.	109.	13.
1996	16.	109.	124.	110.	14.
1997	16.	110.	125.	112.	14.
1998	10.	117.	126.	113.	14.
1999	10.	118.	127.	113.	14.

DEMAND (BILLION KWH)

YEAR	RES.	COM.	IND.	TRANSP.	TOTAL SALES
1980	31.	41.	33.	2.	106.
1981	31.	39.	33.	2.	106.
1982	32.	38.	34.	2.	106.
1983	32.	38.	35.	2.	106.
1984	32.	37.	35.	2.	106.
1985	31.	37.	36.	2.	106.
1986	31.	36.	36.	2.	105.
1987	31.	36.	37.	2.	105.
1988	30.	35.	37.	2.	104.
1989	30.	35.	38.	2.	104.
1990	29.	35.	38.	2.	104.
1991	29.	35.	39.	2.	105.
1992	29.	35.	40.	2.	106.
1993	29.	35.	41.	2.	107.
1994	29.	36.	42.	2.	108.
1995	29.	36.	43.	2.	109.
1996	29.	36.	44.	2.	110.
1997	28.	37.	44.	2.	112.
1998	28.	37.	45.	2.	113.
1999	28.	37.	46.	2.	113.

UPDATE RATES - 1980 $

YEAR	NEW PRICE $/THOUS.KWH	FUEL COMPONENT $/THOUS.KWH	PURCHASED POWER COMPONENT $/THOUS.KWH	LABOR AND OP.&MAINT. COMPONENT $/THOUS.KWH	RETURN TO CAPITAL COMPONENT $/THOUS.KWH
1980	62.	23.	3.	4.	33.
1981	64.	26.	4.	4.	31.
1982	61.	23.	5.	3.	29.
1983	60.	22.	6.	3.	28.
1984	57.	18.	6.	3.	30.
1985	60.	17.	8.	3.	32.
1986	61.	18.	9.	3.	31.
1987	60.	15.	8.	3.	34.
1988	62.	16.	10.	3.	34.
1989	62.	17.	10.	3.	32.
1990	59.	17.	9.	3.	30.
1991	57.	18.	9.	3.	27.
1992	55.	19.	9.	3.	24.
1993	53.	20.	8.	3.	22.
1994	51.	20.	8.	3.	20.
1995	50.	21.	7.	3.	18.
1996	49.	22.	7.	3.	17.
1997	49.	23.	7.	3.	15.
1998	49.	27.	4.	3.	14.
1999	49.	29.	4.	3.	13.

AVERAGE FUEL PRICES - 1980 $ ($/MBTU) (DISPATCHED PLANTS)

YEAR	NUCLEAR	COAL	DO	RO	NG	OTHER FUEL	GASOLINE
1980	0.449639	1.401182	3.742949	4.089380	2.648544		
1981	0.399639	1.461206	4.724421	4.947268	3.011589		
1982	0.349639	1.470369	0.0	4.356898	3.288132		
1983	0.354061	1.501884	0.0	4.442061	3.389051		
1984	0.365456	1.514546	0.0	4.563519	3.546011		
1985	0.369967	1.541022	0.0	4.657457	3.709375		
1986	0.374524	1.556989	0.0	4.776649	3.876349		
1987	0.385189	1.572547	0.0	4.906238	4.072673		
1988	0.389838	1.589484	0.0	5.032878	4.256272		
1989	0.394534	1.605649	0.0	5.177195	4.445639		
1990	0.399276	1.622120	0.0	5.333257	4.642779		
1991	0.404067	1.639234	0.0	5.495121	4.847917		
1992	0.408905	1.656394	0.0	5.663309	5.061424		
1993	0.413792	1.673655	0.0	5.859558	5.277695		
1994	0.418728	1.691088	0.0	6.021596	5.514190		
1995	0.423714	1.708330	0.0	6.204538	5.755665		
1996	0.428750	1.726488	0.0	6.432356	5.991047		
1997	0.433837	1.745130	0.0	6.633458	6.251555		
1998	0.438974	1.767989	0.0	6.824263	6.538417		
1999	0.444164	1.786231	0.0	7.071214	6.806316		

GENERATION, CAPACITY SUMMARY

	AVAILABLE (MW)							DISPATCHED (CAPACITY FACTOR)						
YEAR	COAL	OIL6	GAS	HYDRO	NUC	OIL2	TOTAL	COAL	OIL6	GAS	HYDRO	NUC	OIL2	TOTAL
1980	3530.	11692.	4047.	4021.	3594.	2374.	29258.	0.64	0.34	0.38	0.77	0.58	0.06	0.45
1981	3530.	11692.	4047.	4021.	3594.	2374.	29258.	0.64	0.34	0.38	0.77	0.58	0.00	0.44
1982	3530.	11692.	4047.	4021.	3594.	2374.	29258.	0.63	0.33	0.32	0.77	0.58	0.0	0.43
1983	3530.	11692.	4047.	4021.	3594.	2374.	29258.	0.77	0.27	0.33	0.77	0.58	0.0	0.42
1984	3530.	11692.	4047.	4021.	4403.	2374.	30067.	0.75	0.23	0.32	0.77	0.58	0.0	0.41
1985	4155.	11692.	4047.	4021.	4403.	2374.	30692.	0.73	0.18	0.27	0.77	0.58	0.0	0.39
1986	4155.	11692.	4047.	4021.	4403.	2374.	30692.	0.73	0.18	0.25	0.77	0.58	0.0	0.38
1987	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.70	0.16	0.17	0.77	0.58	0.0	0.37
1988	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.70	0.15	0.15	0.77	0.58	0.0	0.36
1989	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.70	0.15	0.15	0.77	0.58	0.0	0.36
1990	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.70	0.15	0.15	0.77	0.58	0.0	0.36
1991	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.70	0.16	0.15	0.77	0.58	0.0	0.37
1992	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.71	0.17	0.15	0.77	0.58	0.0	0.37
1993	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.71	0.18	0.13	0.77	0.58	0.0	0.38
1994	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.72	0.19	0.15	0.77	0.58	0.0	0.38
1995	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.72	0.20	0.15	0.77	0.58	0.0	0.39
1996	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.73	0.23	0.11	0.77	0.58	0.0	0.39
1997	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.73	0.24	0.11	0.77	0.58	0.0	0.39
1998	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.75	0.29	0.15	0.77	0.58	0.0	0.42
1999	4155.	11692.	4047.	4021.	5483.	2374.	31772.	0.75	0.31	0.12	0.77	0.58	0.0	0.42

GENERATION, ENERGY SUMMARY

PRODUCED (GWHR)

YEAR	COAL	OIL6	GAS	HYDRO	NUC	OIL2	TOTAL
1980	19692.	34662.	13349.	27141.	18115.	1177.	114135.
1981	19697.	34367.	13455.	27141.	18115.	98.	112873.
1982	19537.	33934.	11205.	27141.	18115.	0.	109933.
1983	23827.	27805.	11591.	27141.	18115.	0.	108479.
1984	23180.	23594.	11325.	27141.	22193.	0.	107433.
1985	26688.	18930.	9402.	27141.	22193.	0.	104353.
1986	26680.	18350.	8745.	27141.	22193.	0.	103108.
1987	25420.	16566.	5908.	27103.	27637.	0.	102633.
1988	25352.	15867.	5419.	27141.	27637.	0.	101415.
1989	25397.	15424.	5419.	27141.	27637.	0.	101017.
1990	25498.	15585.	5390.	27141.	27637.	0.	101250.
1991	25641.	16184.	5390.	27141.	27637.	0.	101992.
1992	25810.	17109.	5390.	27141.	27637.	0.	103086.
1993	25988.	18854.	4774.	27141.	27637.	0.	104393.
1994	26162.	19558.	5304.	27141.	27637.	0.	105802.
1995	26322.	20715.	5390.	27141.	27637.	0.	107203.
1996	26459.	23242.	4056.	27141.	27637.	0.	108534.
1997	26571.	24375.	4039.	27141.	27637.	0.	109762.
1998	27324.	29372.	5390.	27141.	27637.	0.	116863.
1999	27347.	31288.	4094.	27141.	27637.	0.	117507.

GENERATION, FUEL PRICE SUMMARY

PRODUCED ($/MWHR)

COAL	OIL6	GAS	HYDRO	NUC	OIL2	TOTAL
14.85	42.78	30.81	0.0	4.97	60.38	20.57
15.48	51.71	35.38	0.0	4.42	72.96	23.44
15.58	45.38	37.24	0.0	3.87	0.0	21.21
15.99	45.83	37.35	0.0	3.92	0.0	19.90
16.09	47.01	39.13	0.0	4.04	0.0	18.75
16.35	47.45	41.20	0.0	4.09	0.0	17.37
16.52	48.46	43.15	0.0	4.14	0.0	17.45
16.69	49.61	44.67	0.0	4.26	0.0	15.86
16.88	50.72	46.85	0.0	4.31	0.0	15.83
17.05	52.13	48.93	0.0	4.36	0.0	16.06
17.22	53.70	51.01	0.0	4.41	0.0	16.52
17.39	55.37	53.27	0.0	4.46	0.0	17.18
17.56	57.14	55.61	0.0	4.52	0.0	18.00
17.74	59.43	57.28	0.0	4.57	0.0	18.98
17.93	61.08	60.49	0.0	4.63	0.0	19.96
18.11	63.11	63.24	0.0	4.68	0.0	21.03
18.30	66.07	63.76	0.0	4.74	0.0	22.20
18.50	68.18	66.49	0.0	4.79	0.0	23.27
18.77	70.28	71.84	0.0	4.85	0.0	26.51
18.96	73.03	72.52	0.0	4.91	0.0	27.54

FOSSIL FUEL CONSUMPTION SUMMARY

(TRILLION BTU/YEAR)

YEAR	COAL	OIL	GAS	TOTAL
1980	209.28	360.74	155.24	725.27
1981	209.33	357.69	157.83	724.85
1982	207.64	351.93	126.92	686.49
1983	254.46	285.92	127.69	668.07
1984	246.99	242.27	124.91	614.18
1985	283.79	192.42	104.38	580.59
1986	283.70	185.86	97.32	566.88
1987	270.49	167.30	64.78	502.57
1988	269.78	159.79	59.62	489.20
1989	270.25	155.21	59.62	485.09
1990	271.25	156.81	59.20	487.26
1991	272.60	162.94	59.20	494.74
1992	274.29	172.46	59.20	505.95
1993	276.12	190.98	51.80	518.90
1994	277.92	198.13	58.17	534.22
1995	279.65	210.41	59.20	549.25
1996	281.10	238.25	43.17	562.52
1997	282.30	250.04	42.95	575.29
1998	290.66	301.90	59.20	651.76
1999	290.93	322.49	43.62	657.04
TOTAL	5302.52	4663.56	1614.02	11580.08

TOTAL RESIDUALS

1000 TONS/YR

	AIR					LAND	
YEAR	TSP	COAL SO2	OIL SO2	TOTAL SO2	NOX	ASH	SLUDGE
1980	10.46	319.33	262.94	582.27	0.0	304.99	0.0
1981	10.47	319.42	257.77	577.19	0.0	305.05	0.0
1982	10.38	316.40	256.64	573.05	0.0	303.11	0.0
1983	12.72	382.96	214.02	596.98	0.0	366.44	0.0
1984	12.35	373.31	180.62	553.93	0.0	356.02	0.0
1985	14.19	378.04	145.30	523.34	0.0	398.44	0.0
1986	14.18	377.94	141.97	519.90	0.0	398.34	0.0
1987	13.52	358.02	128.97	486.99	0.0	380.54	0.0
1988	13.49	356.78	124.66	481.44	0.0	379.28	0.0
1989	13.51	357.61	121.75	479.36	0.0	380.12	0.0
1990	13.56	359.20	122.88	482.08	0.0	381.77	0.0
1991	13.63	361.21	127.45	488.66	0.0	383.91	0.0
1992	13.71	363.86	134.54	498.39	0.0	385.91	0.0
1993	13.81	366.78	147.37	514.14	0.0	387.78	0.0
1994	13.90	369.64	154.91	524.56	0.0	389.62	0.0
1995	13.98	372.44	165.05	537.48	0.0	392.46	0.0
1996	14.06	375.03	182.90	557.93	0.0	394.13	0.0
1997	14.11	376.78	191.32	568.10	0.0	395.44	0.0
1998	14.53	386.30	235.79	622.09	0.0	406.13	0.0
1999	14.55	386.74	244.97	631.71	0.0	406.54	0.0
TOTAL	265.12	7257.61	3541.79	10799.39	0.0	7495.84	0.0