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# A FINANCIAL MODEL FOR THE ELECTRIC UTILITY INDUSTRY

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The serious economic and financial problems faced by the investor-owned electric utility industry stem largely from the fact that electric rates have not kept pace with the costs of the factors of production, especially plant construction and capital. Symptomatic of the problem are the difficulties which some utilities find in their efforts to raise capital. Investors recognize the risk that regulatory bodies may be unwilling to provide timely and equitable rate increases and therefore demand higher returns on invested capital or refuse to make capital available at all. Eventually, the electric utilities must cut back on capital investment and risk not being able to satisfy the future demand for electricity.

While the link between cost and availability of capital and regulatory risk is quite strong, operating and financial characteristics of the industry contribute further to the risk assumed by an investor. Such characteristics include the high proportion of fixed operating costs, the high proportion of debt in the capital structure, and the strong dependence on external financing. While in the past such risks were thought to be offset by steadily growing demand, productivity through improved technology, and an accomodating regulatory environment, this is no longer the case. If anything, these same factors now contribute to the risks!

A wide variety of suggestions for coping with the industry's problems have surfaced during the past two years. Government purchase of utility securities, government guarantee of utility debt, and utility tax relief through higher investment tax credits serve to shift the burden of higher costs for power generation and distribution to the general tax base. Rate structure changes and efforts to speed up the regulatory process place the higher costs burden more directly on the users of power. Another suggestion would encourage industry power generation both for industry use and for sale to utilities as well as industry-utility joint venture power production. Under these alternatives, real savings in power production costs derive from a more efficient utilization of capital equipment in steam and electricity generation. The purpose of this study is to examine the financial effects of several alternative industry-utility generation cases.[1/]

## The Utility Model

### Overview

The financial and economic effects of increased industrial power generation and industry-utility joint-venture central power stations are projected by a multiperiod accounting model of the investor-owned electric utilities. Industry aggregate financial statements for 1956-1972 set the initial conditions.[2/] Given forecast demand, and costs for generating plant, operations, and financing, the model calculates an annual income statement and a year-end balance sheet for the industry. These statements set the new initial conditions for the following year. The calculation proceeds iteratively to yield annual financial statements through 1985. Known financial results for the investor-owned electric utility industry for 1973 and 1974 provide a check on the reliability of the model. A schematic representation of the model structure is shown in Figure 1.

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1/ This paper is based on the economic and financial chapter of the Energy Industrial Center Study. The author wishes to express appreciation to the National Science Foundation for financial support and to the following individuals for their roles in the development of the study: Edward B. Mitchell, The University of Michigan; Ann Arbor; Lowel B. Wiltbank, Townsend-Greenspan and Company, New York; Robert S. Spencer, The Dow Chemical Company, Midland, Michigan.

2/ U.S., Federal Power Commission, Statistics of Privately-Owned Electric Utilities in the United States -- 1964-1972.

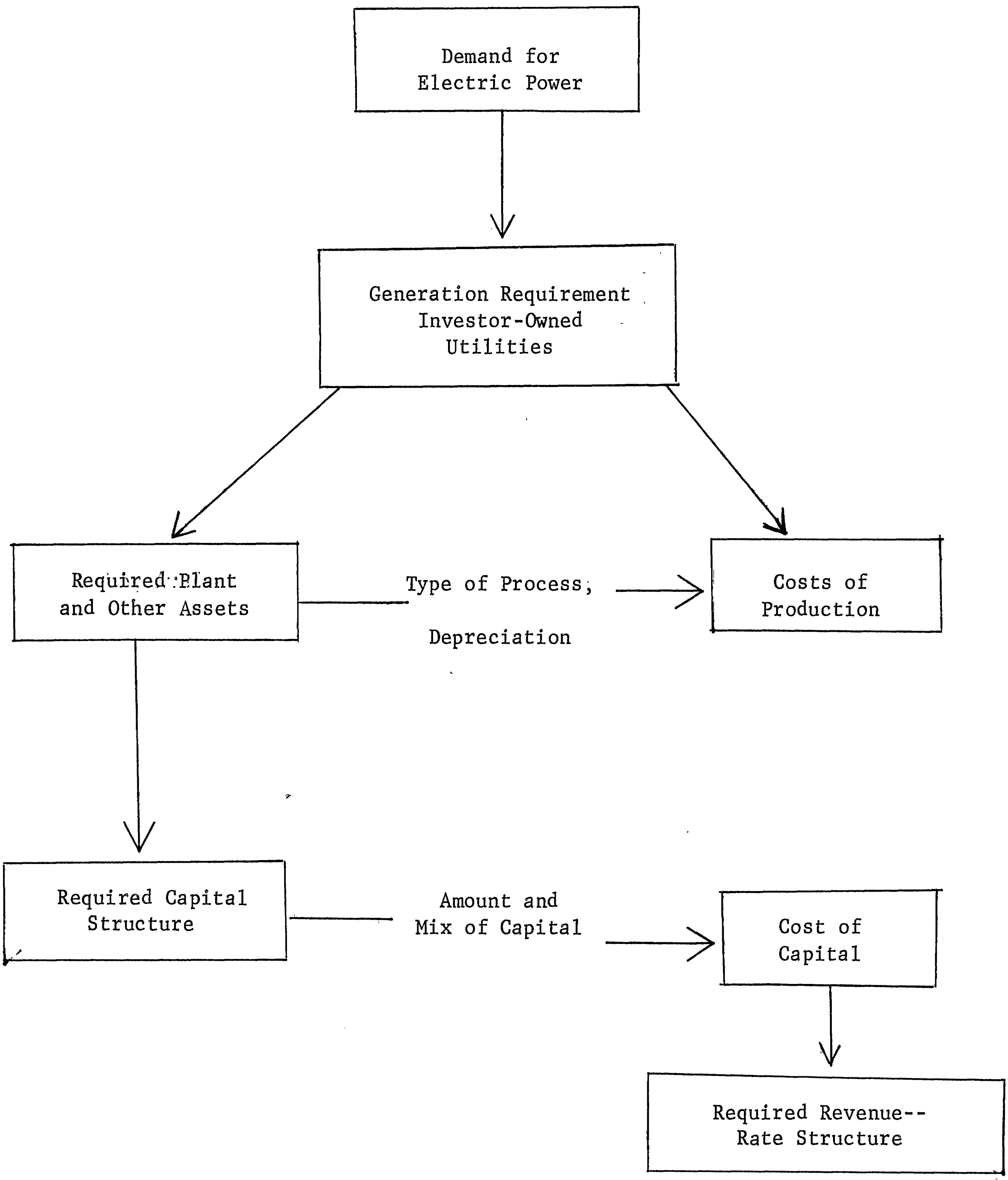


Fig. 1. Schematic diagram of the utility financial model.

The model does not determine the impact of alternative generation cases on industry or on the joint ventures. Estimates of the capital expenditures and financing for nonutility power generation are developed exogenous to the model. These data are combined with the model results for investor-owned utilities to develop a comparison of generation alternatives on a total system basis.

## Model Structure and Assumptions

### Demand forecast

The total annual energy demand for the electric utility industry was developed by forecasting and aggregating the demand by consuming sector. Table 1 provides the forecast data and Figure 2 shows a graphical comparison of past demand to forecast demand. Although a detailed description of the forecasting procedure will not be included in this paper, the following summary of the techniques employed within each consuming group may be helpful.

Residential. Total annual household consumption of electrical power is determined by forecasting the usage-rate per household and multiplying by a forecast number of households. The number of households depends upon demographic factors including population, family formation, and housing starts. Electrical energy use-rate per household is the aggregate of the products of use rate by appliance and appliance saturation levels.[3/] Total residential consumption is the sum of total household consumption and a forecast "all other" residential use which includes residential lighting and uses not considered in the analysis by appliance.

Industrial. Total annual industrial electric power consumption is the aggregate of power consumption forecasts by industry. A historical ratio

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3/ Appliances include refrigerators, freezers, ranges, dishwashers, clothes washers, dryers, television, water heaters, air conditioners, and space heaters.

TABLE 1

Forecast of Energy Demand--Total Electric Utility Industry
(billions KWH)

| Year | Residential | Commercial | Industrial | Other | Total |
|---|---|---|---|---|---|
| 1973 | 554.2 | 471.2 | 612.9 | 64.9 | 1703.2 |
| 1974 | 595.0 | 489.5 | 626.2 | 65.8 | 1776.5 |
| 1975 | 645.2 | 516.9 | 644.7 | 68.1 | 1874.9 |
| 1976 | 694.2 | 551.7 | 667.7 | 71.0 | 1984.6 |
| 1977 | 739.3 | 593.0 | 706.9 | 76.0 | 2115.2 |
| 1978 | 783.0 | 625.8 | 730.8 | 82.0 | 2221.6 |
| 1979 | 826.8 | 666.5 | 752.1 | 87.0 | 2332.4 |
| 1980 | 871.1 | 707.4 | 796.3 | 92.2 | 2467.0 |
| 1981 | 915.4 | 746.7 | 837.2 | 97.4 | 2596.7 |
| 1982 | 959.2 | 785.8 | 866.8 | 103.8 | 2715.6 |
| 1983 | 1002.5 | 826.7 | 913.5 | 110.1 | 2852.8 |
| 1984 | 1044.8 | 867.4 | 963.6 | 116.6 | 2992.4 |
| 1985 | 1085.4 | 909.2 | 1015.2 | 124.0 | 3133.8 |
| Percentage Annual Growth Rate | | | | | |
| 1973-1985 | 5.8 | 5.6 | 4.3 | 5.5 | 5.2 |
| 1960-1972 | 8.3 | 6.6 | 4.5 | 7.6 | 5.8 |

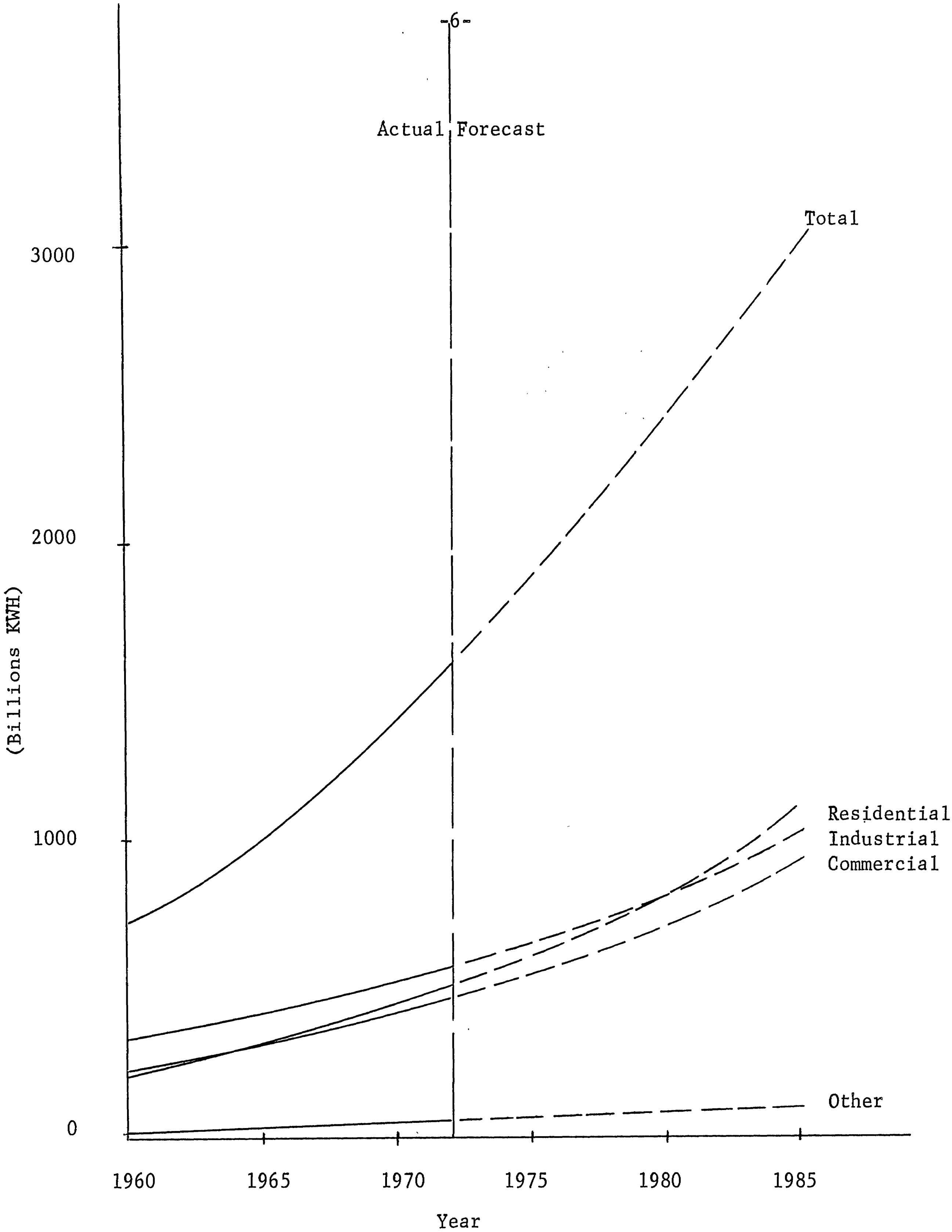


Fig. 2. Forecast of electrical energy consumption in 1985.

of electric energy consumed to the Federal Reserve Board (FRB) Industrial Production Index is developed and then forecast by industry. A forecast value of the FRB Industrial Production Index by industry by year multipled by the forecast consumption ratio yields the forecast of electric energy use. Aggregate annual industry forecasts are modified by amounts of electric power "generated less sold" to yield industrial demand to the utilities.[4/]

Commercial. Total annual commercial electric power consumption is forecast as the sum of five component uses. Consumption for air conditioning is the product of a forecast of commercial floor area and an extrapolation of the ratio of electric power consumed for air conditioning to floor area. Refrigeration use in public eating places and institutions is forecast as a function of the forecast of deflated personal consumption expenditures away from home. Refrigeration consumption in supermarkets is related to the forecast for this type of floor space. Space heating and "all other" uses are based on historical relationships to total commercial consumption.

Other. Consumption of electric energy for street and highway lighting, public authorities, railroad and railways, interdepartmental, and miscellaneous uses is forecast by extrapolation of the demand in each category.

Generating capacity

The total utility industry used in forecasting demand consists of investor-owned utilities, Rural Electrification Administration (REA) financed utility cooperatives, and government-owned utilities. Because this study is concerned with the development of financial statements for

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4/ The ratio of industry generation/industry consumption is assumed to follow the declining trend of the recent past and fall to approximately 0.08 by 1985.

investor-owned utilities, the part of total demand realized by these firms must be calculated. To do this, the relationship of power sales by investor-owned utilities to total utility sales within each consuming sector is measured from historical data, forecast, and applied to the total demand estimates to yield demand to investor-owned utilities. Required generation is derived from total demand to investor-owned utilities by aggregating the effects of demand, company use, exports, losses, and net power transfers. Each of these factors is forecast for the study period by assuming stability in the historical relationships.

The capacity necessary to meet required generation depends on the existing plant type mix, retirements, plant-type additions, and assumed load factors by type of plant. Plant-type mix and load factor assumptions are shown in Tables 2 and 3. Existing plant-type mix at the beginning of a period is read from historical data for January 1, 1973, and calculated in the model thereafter. Annual asset retirements are estimated through use of a survival curve.[5/]

Balance Sheet--assets

1. Generation plant

The beginning book value of generation plant is increased by the value of plant acquired during each year. In this discussion, plant is acquired when completed. Assets Under Construction and Depreciation are described under separate headings below. The value of plant acquired, by type, is the product of plant capacity acquisitions and per $KW investment values for average size new plants as shown in Table 4.

2. Transmission, distribution, nuclear fuel, and other assets

The forecasting procedure for gross fixed assets is similar in each

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5/ An explanation of the survival curve procedure is given in the Energy Industrial Center Study, Chapter VI.

TABLE 2

Mix of Gross Additions to Generating Capacity
(Percentage of Added Capacity)

| Year | Coal | Oil | Gas | Nuclear | Combined Cycles | Peaking Gas Turbines |
|---|---|---|---|---|---|---|
| 1974 | 29.8 | 18.9 | 4.7 | 31.7 | 2.3 | 12.6 |
| 1975 | 40.2 | 17.9 | 0.9 | 25.9 | 2.5 | 12.6 |
| 1976 | 39.9 | 16.9 | | 30.5 | 3.8 | 8.9 |
| 1977 | 47.0 | 17.3 | | 19.6 | 5.5 | 10.6 |
| 1978 | 57.0 | 7.4 | | 25.5 | 1.5 | 8.6 |
| 1979 | 58.7 | | | 30.3 | 2.0 | 9.0 |
| 1980 | 45.1 | | | 45.5 | 1.9 | 7.5 |
| 1981 | 28.5 | | | 59.8 | 2.8 | 8.9 |
| 1982 | 22.8 | | | 64.6 | 4.3 | 8.3 |
| 1983 | 22.6 | | | 61.0 | 7.3 | 9.1 |
| 1984 | 19.0 | | | 61.1 | 10.6 | 9.3 |
| 1985 | 14.4 | | | 61.9 | 14.2 | 9.5 |

TABLE 3

Projected Load Factors
(Percentage of Capacity)

| Year | Coal, Oil, Gas Combined Cycle | Nuclear | Hydro | Peaking Gas Turbines |
|---|---|---|---|---|
| 1974 | 57.1 | 78.6 | 48 | 17.7 |
| 1975 | 56.7 | 79.2 | | |
| 1976 | 55.8 | 79.7 | S | S |
| 1977 | 55.6 | 80.3 | A | A |
| 1978 | 55.1 | 80.9 | M | M |
| 1979 | 54.5 | 81.5 | E | E |
| 1980 | 53.2 | 82.1 | | |
| 1981 | 51.6 | 82.7 | | |
| 1982 | 49.6 | 83.2 | | |
| 1983 | 47.8 | 83.8 | | |
| 1984 | 45.8 | 84.4 | | |
| 1985 | 43.8 | 85.0 | | |

TABLE 4

Investment in Average Size New Plants
($/KW)

| Operational | Coal | Oil | Gas | Nuclear | Combined Cycle | Peaking Gas Turbines |
|---|---|---|---|---|---|---|
| 1974 | 346 | 303 | 243 | 355 | 131 | 95 |
| 1975 | 373 | 325 | 262 | 378 | 141 | 102 |
| 1976 | 392 | 341 | 274 | 405 | 152 | 110 |
| 1977 | 419 | 363 | | 432 | 164 | 118 |
| 1978 | 457 | 395 | | 461 | 177 | 128 |
| 1979 | 498 | 429 | | 498 | 190 | 137 |
| 1980 | 533 | | | 551 | 206 | 148 |
| 1981 | 572 | | | 596 | 222 | 160 |
| 1982 | 613 | | | 653 | 239 | 172 |
| 1983 | 657 | | | 706 | 258 | 185 |
| 1984 | 707 | | | 762 | 278 | 200 |
| 1985 | 753 | | | 824 | 299 | 215 |

The coal and the oil-fired plants are fitted with sulfur dioxide removal equipment.

of these categories. First, a historical ratio of asset level to associated activity indicator is developed. Transmission assets are associated with number of miles of electric line, distribution assets are tied to number of customers, nuclear fuel to nuclear plant, and other assets to number of customers. Then the value of the activity indicator is forecast (e.g., number of customers) or calculated (e.g., nuclear plant). The product of the ratio, which is assumed to be stable, and the activity indicator is gross fixed assets by type.

3. Assets under construction and capitalized cost of construction funds

Multiperiod construction time for many utility assets and certain utility accounting procedures give rise to these asset categories. Assets under Construction measures investment in assets which are not yet in service. The value is developed in the model by estimating the duration and pattern of construction expenditures for each class of asset. Given the plant required to satisfy demand as calculated in sections 1 and 2 above, the capital expenditure distributions yield the amount of increase in Assets under Construction during each period. Assets under Construction decreases with completions when the value of completed plant is moved to the appropriate plant asset category. The depreciation item does not apply to Assets under Construction.

Capitalized Cost of Construction Funds is the accumulated value of financing costs for funds supporting construction which are not expensed in the current income statement. In effect, these expenses are viewed as are other expenses during construction (e.g., labor) and are included as part of the depreciable investment base when construction is complete. The item is carried separately in the model balance sheets as a calculating convenience.

4. Depreciation

All asset categories included above are subject to depreciation except Assets under Construction, as noted. The annual depreciation charge by asset category is calculated by multiplying gross depreciable assets by an estimated straight-line depreciation rate. This estimated rate is the inverse of estimated mean life for each asset category. Mean life estimates are developed through a trial and error process of recreating the historical series of accumulated depreciation. The rate applied to capitalized cost of construction funds is the weighted average of the rates applied to other categories of assets.

5. Other assets

Three remaining asset items are needed to complete the asset side of the balance sheet: Other Utility Plant, Current Assets, and Other Assets and Debits. Each is calculated by assuming continuance of its historical ratio to net electric utility plant.

<u>Balance Sheet--liabilities and equity</u>

Total liabilities and equity are forced to equal total assets as determined in the previous section. The breakdown of types of capital employed depends on assumed managerial policies regarding capital structure and dividends.

1. Capital structure

The current long term capital structure of 35 percent common equity, 12 percent preferred stock, and 53 percent long term debt is assumed to change gradually by 1980 to 35 percent common equity, 15 percent preferred stock, and 50 percent long term debt, which is the target structure through 1985. This policy assumption reflects an attempt on the part of financial managers to improve the overall equity position of the utilities. Current

Liabilities, Other Long Term Liabilities, and Other Liabilities and Credits are maintained in the historical proportions to long term bonds.

2. Dividend policy

The dividend payout rate is assumed to be maintained at 65 percent throughout the forecast period. As the return on common equity increases gradually toward the allowed return (detailed below) the proportion of total common equity represented by retained earnings increases.

The Income Statement

Development of annual income statements requires a bottom-up approach proceeding from calculations of capital and operating costs to the determination of required revenue.

1. Capital costs

The market rate paid for different forms of capital during the forecast period is based on forecasts of the AAA bond rate and on assumed yield differentials from that rate. The AAA bond rate forecast is developed by a distributed lag multiple regression model using independent variables which capture the effects of changes in the consumer price index and in the ratio of gross national product to money supply (M2). Yield differentials are assumed to correspond roughly to historical relationships. Table 5 displays the rates used for each type of capital through 1985. The return on common equity yield differential is not assumed to be constant throughout the period. To reflect the fact that current return on common equity is far below the rate allowed by regulatory bodies, the yield differential is assumed to rise gradually from the current spread of about 100 basis points above the AAA bond rate to a spread of 400 basis points by 1982.

Calculating the preferred dividend and interest expense requirement is not quite as simple because the rates paid on past issues which still

TABLE 5

Interest Rate Forecasts
(Percentage)

| Year | AAA Bond Rate | Utility Bond Rate | Preferred Stock Dividend Rate | Return on Common Equity | Rate on Construction Funds |
|---|---|---|---|---|---|
| 1975 | 9.2 | 10.2 | 11.2 | 10.2 | 8.8 |
| 1976 | 9.6 | 10.6 | 11.6 | 10.5 | 9.2 |
| 1977 | 9.6 | 10.6 | 11.7 | 10.8 | 9.2 |
| 1978 | 9.6 | 10.6 | 11.6 | 10.2 | 9.2 |
| 1979 | 9.3 | 10.3 | 11.3 | 11.5 | 8.9 |
| 1980 | 9.0 | 10.0 | 11.0 | 11.8 | 8.6 |
| 1981 | 8.7 | 9.7 | 10.7 | 12.1 | 8.3 |
| 1982 | 8.4 | 9.4 | 10.4 | 12.4 | 8.0 |
| 1983 | 8.3 | 9.3 | 10.3 | 12.3 | 7.9 |
| 1984 | 8.3 | 9.3 | 10.3 | 12.3 | 7.9 |
| 1985 | 8.3 | 9.3 | 10.3 | 12.3 | 7.9 |

remain in the capital structure determine the dollar amount of the payout to bondholders and owners of preferred stock. The calculations necessary to determine these financing expenses must reflect rate levels appropriate to time of issuance and retirements. A survival curve analysis similar to that used for assets is employed. Preferred dividends are therefore calculated as the prior period payout plus payments on new sales of preferred stock minus payments on issues retired. Because the dividend rates on retired issues are significantly below current rates, preferred stock dividend payments grow faster than does the amount of preferred stock outstanding. Interest expense on long term bonds and other liabilities is calculated similarly.

2. Taxes

State and local taxes are the major components of the expense item called taxes (excluding Federal Income Tax). Since such taxes are based primarily on value of property, the amount is forecast by assuming continuation of the historical ratio of the tax expense to gross fixed assets. Federal Income Tax is forecast by calculating the historical average-rate-per-period on income and extrapolating it to the future. An exact calculation of this item would include explicitly the effects of accelerated depreciation, investment tax credit, and the tax schedule. The data inputs necessary for such a computation were unavailable for use in this study.

3. Allowance for funds used during construction

In order to offset the impact on net income of financing costs associated with assets under construction, electric utilities include an item called Allowance for Funds Used during Construction as an addition to the income statement. The effect of this addition on the balance sheet and on future income statements has already been explained in the asset development section of the report. The historical rate used to determine the allowance has averaged about 140 basis points below the utility bond rate. The last column in Table 5 displays the rates assumed in the forecast obtained by using the average yield differential.

4. Operating costs

The mix of generating plant type employed in each period has been determined in the preceeding section on generating plant assets. For each plant type, fuel expense ($) is equal to the product of capacity (KW), annual hours (8760 hours), load factor (percent), heat rate (BTU/KWH) and fuel price ($\$/10^6$BTU). Total fuel expense is the sum of these products. Assumed fuel prices and heat rates are displayed in Tables 6 and 7.

Non-fuel operating expenses include the costs of labor, materials, and facilities for producing power. An estimate of this expense is determined as the product of the historical ratio of non-fuel operating expense to KWH generated and the forecast demand. Operating costs outside the power generating area were estimated on the basis of historical relationships to activity indicators in each area. Transmission costs were related to miles of line; distribution costs were related to the number of customers, as were sales, administrative, and general expenses. Costs not readily classifiable were related to generating capacity.

Maintenance expense is forecast by multiplying calculated gross fixed asset level by the historical ratio of maintenance expense to gross fixed assets.

The annual depreciation expense used in determining operating expenses was calculated as part of the balance sheet developed for funds used during construction. In each period, therefore, sufficient revenue is provided to allow the industry to earn the forecast rate of return on the book value of shareholders equity.

Rate Structure

Electric utility rate structures are designed to require customers to pay for electric service in proportion to the cost of providing service.

TABLE 6

Projected Fuel Prices ($\$/10^6$BTU)

| Year | High Sulfur Coal | Nuclear | Average Utility Gas | Crude Oil and High Sulfur Residual Oil | Low Sulfur Residual Oil | #2 Distillate |
|---|---|---|---|---|---|---|
| 1974 | 0.58 | 0.22 | 0.48 | 2.00 | 2.30 | 2.50 |
| 1975 | 0.69 | 0.23 | 0.60 | 2.26 | 2.60 | 2.83 |
| 1976 | 0.80 | 0.25 | 0.74 | 2.44 | 2.81 | 3.05 |
| 1977 | 0.91 | 0.26 | 0.92 | 2.64 | 3.03 | 3.30 |
| 1978 | 1.02 | 0.27 | 1.11 | 2.85 | 3.27 | 3.56 |
| 1979 | 1.14 | 0.29 | | 3.07 | 3.54 | 3.84 |
| 1980 | 1.25 | 0.30 | | 3.32 | 3.82 | 4.15 |
| 1981 | 1.37 | 0.32 | | 3.52 | 4.05 | 4.40 |
| 1982 | 1.50 | 0.33 | | 3.73 | 4.29 | 4.66 |
| 1983 | 1.62 | 0.35 | | 3.95 | 4.55 | 4.94 |
| 1984 | 1.74 | 0.37 | | 4.19 | 4.82 | 5.24 |
| 1985 | 1.87 | 0.39 | | 4.44 | 5.11 | 5.55 |

TABLE 7

Heat Rate (BTU/KWH)

| Coal | Oil | Gas | Nuclear | Combined Cycle | Peaking Gas Turbines |
|---|---|---|---|---|---|
| 10,300 | 10,300 | 10,300 | 10,300 | 9,200 | 15,000 |

Because actual cost allocation procedures vary widely among electric utilities, a representative cost allocation technique has been developed in the model to forecast industry rates and revenue by customer class.

Expenses for fuel, plant operations, and transmission are allocated to customer class in proportion to KWH consumption. Distribution expense and customer-related office expense are allocated in proportion to the number of customers served. The allocation of all other expenses, including maintenance, depreciation, administration, taxes, and capital cost, is accomplished by assuming stability between the ratio of power distribution costs (fuel, plant operation, and transmission expense) to total expense, and the all other cost ratio (all other expenses to total expense), in each consuming class. The rate charged to each class is calculated by dividing total allocated cost by demand.

## The Generation Cases

### Overview

This section describes the alternative cases for increased industrial power generation and industry-utility joint venture central power stations. Figure 3 shows a schematic representation of the alternatives.

Each of the four cases, designated "A" through "D," is an independent alternative to the base case, and each is in some sense a maximum implementation case. The analytical method used in the following sections is to compare the capital expenditure, financing, and rate implications of each case relative to the base. Because the policy and price assumptions relating to operations, investment, and financing are held constant throughout the analysis, any differences should be the result of changes in power generation procedure.

### Detailed description of the cases

The base case. The demand forecast described in an earlier section assumed that the historical ratio of industrial power generated to power consumed would

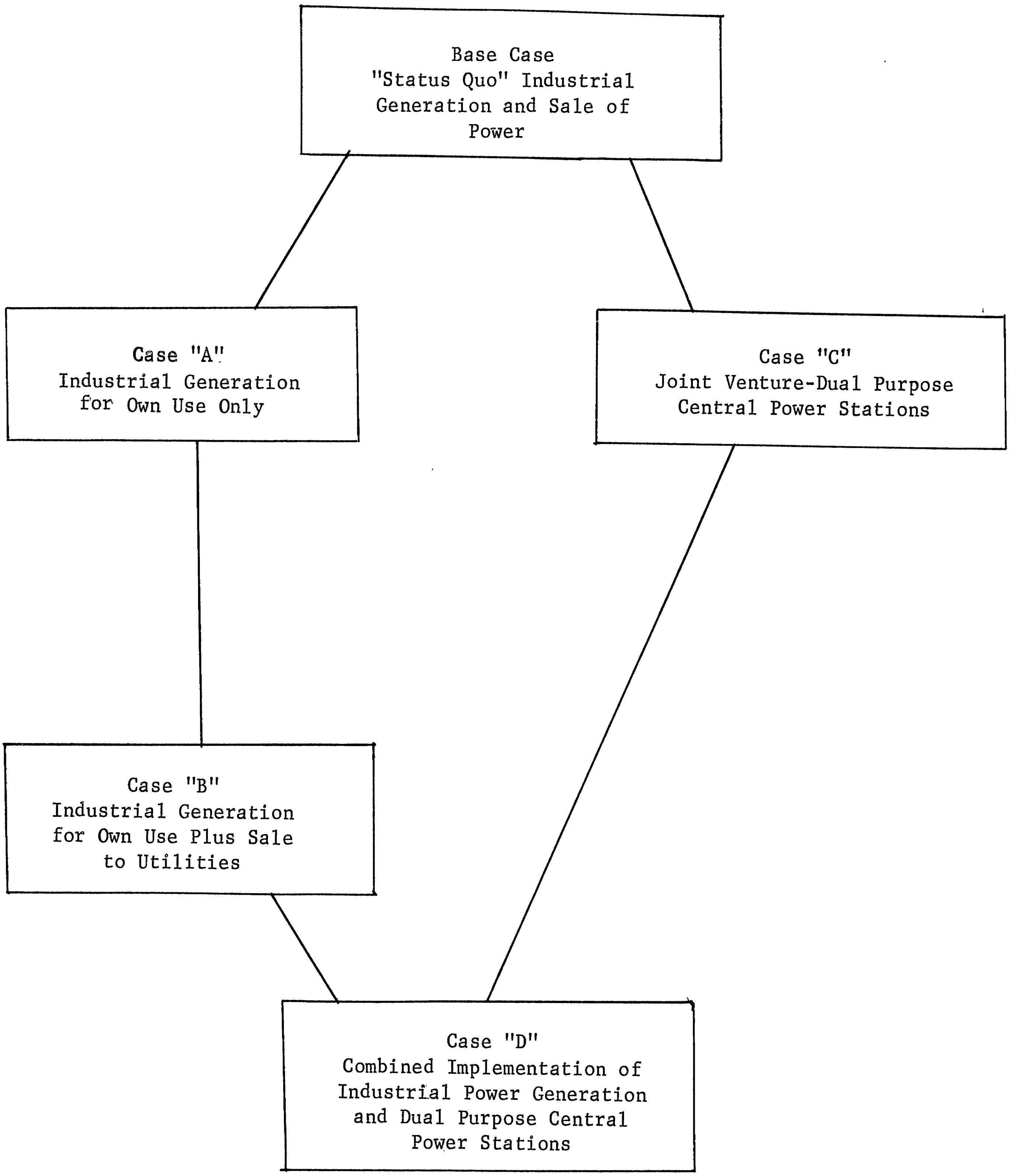


Fig. 3. Alternative generation cases.

continue to fall from the 1972 value of about 0.14 to 0.08 in 1985. This, then, represents the assumption for industrial generation used in the base case analysis.

In summary, the major assumptions are:

(1) The proportion of total power sales by investor-owned utilities remains at the historical value;

(2) The mix of plant-type additions is given by Table 2;

(3) Load factors by plant type are given in Table 3;

(4) ($/KW) for investment in generating plant is provided in Table 4;

(5) Association between certain non-generation assets and activity indicators is constant:

Transmission per mile of electric line

Distribution per number of customers

Nuclear fuel per nuclear plant

Other assets per gross fixed assets;

(6) Future depreciation rates correspond to those employed in the past (that is, mean asset life, by category, is constant);

(7) The target capital structure of 35 percent equity, 15 percent preferred stock, and 50 percent debt is reached by 1980 and maintained thereafter;

(8) The dividend payout ratio is constant at 65 percent;

(9) Yield differentials for various forms of utility capital give rates of return as provided by Table 5;

(10) The effective federal income rate does not change from that prevailing in the early 1970s;

(11) Fuel prices are given in Table 6;

(12) Heat rates are given in Table 7;

(13) Non-fuel operating costs continue in the historical ratio to appropriate activity indicators;

(14) Maintenance expense per gross fixed assets is constant at the historical level.

Industrial generation

Typical existing industrial power plants which are currently employed only to generate steam for process use are technically and economically unsuitable for by-product power generation. Power plants which are capable of producing by-product power either for own use or for sale to utilities, are assumed to do so. Thus, the opportunities for increased industrial generation exist only for new power plant installations.

The addition of by-product power generation capability to a typical "steam-only" plant requires incremental installation of a high pressure boiler and a mixed pressure turbine system. For a typical 20-MW power system, the return on incremental investment generated by savings on power purchased from utilities is between 17 percent and 22 percent depending on the assumed incremental investment. A range of generator sizes from 5-MW to 100-MW provides returns from 9 to 35 percent. Assuming a minimum required return on investment of 20 percent, by-product power installations above 400,000 pounds per hour of process steam or 20-MW of power generation are economically viable. Approximately 43 percent of existing steam installations generate 400,000 pounds per hour of process steam, or more. By estimating the 1980 industrial steam load, backing out the part generated by facilities already in place and applying the 43 percent acceptable size of installation factor, it is determined that the potential for new by-product power generation in 1980 is 26,806-MW. An assumed installation schedule of one-third the 1980 potential in each of 1978, 1979, and 1980 and an assumed growth rate of 4.5 percent per year beyond, yields the by-product power generation potential annually from 1978-85.

Generation of incremental condensing power from a typical steam/electricity plant of the type described above requires further incremental investment to increase flow through the condenser. Incremental investment in condensing power for a 20-MW generating unit to increase capacity to 30-MW yields a 27 percent return on investment. Incremental investment in condensing power to double the output of the 20-MW unit is justified by a return slightly greater than 20 percent.

1. Industrial generation for own use, Case A

In this case, industry is assumed to take advantage of all opportunities to generate by-product power which yields a before tax return on investment greater than 20 percent. Industry is also assumed to invest in incremental condensing power sufficient to increase new capacity to 150 percent of the by-product power amount. Power production beyond this level is in excess of that required to satisfy industrial need.

2. Industrial generation for own use plus sale to utilities, Case B

This case assumes that industry builds all of the capacity envisioned in Case A. In addition, industry is assumed to invest an additional 20 percent of the Case A required investment in additional incremental condensing power. Since all the incremental power produced is in excess of industry needs, it is assumed to be sold to utilities. Note that although returns in excess of 20 percent are available for still further investment in condensing power, a reluctance to go beyond this point is assumed. This is shown in Table 8.

<u>Joint-venture central power stations, Case C</u>

The dual-purpose central power stations analyzed in this case produce both electricity and process steam. The joint venture sells steam to industry and electricity to the utilities. For purposes of this analysis, coal-fired,

TABLE 8

Comparison of Generating Requirements--Base Case, Cases A and B

| Year | Base Case Utilities Generation Requirement (million KWH) | Case "A" Industrial Generation for Own Use | | Case "B" Industrial Generation for Own Use plus Sale to Utilities | |
|---|---|---|---|---|---|
| | | Utilities Generation Requirement (million KWH) | Percentage Change from Base Case | Utilities Generation Requirement (million KWH) | Percentage Change from Base Case |
| 1976 | 1,674.8 | 1,674.8 | 0 | 1,674.8 | 0 |
| 1977 | 1,802.6 | 1,802.6 | 0 | 1,802.6 | 0 |
| 1978 | 1,912.0 | 1,831.8 | (4.2) | 1,792.4 | (6.3) |
| 1979 | 2,009.4 | 1,841.5 | (8.4) | 1,760.3 | (12.4) |
| 1980 | 2,125.8 | 1,862.2 | (12.4) | 1,734.9 | (18.4) |
| 1981 | 2,237.3 | 1,961.3 | (12.3) | 1,828.3 | (18.3) |
| 1982 | 2,338.1 | 2,050.4 | (12.3) | 1,911.3 | (18.3) |
| 1983 | 2,455.1 | 2,154.6 | (12.2) | 2,009.5 | (18.1) |
| 1984 | 2,574.2 | 2,260.5 | (12.2) | 2.108.8 | (18.1) |
| 1985 | 2,694.4 | 2,366.9 | (12.2) | 2,208.8 | (18.0) |

dual-purpose, central power stations are assumed to displace all coal-fired utility plants which become operational in the base case during 1979 and beyond. Nuclear stations replace all base case utility nuclear facilities during 1981 and beyond.

The joint ventures are financed with 50 percent equity from the industry-utility partners and 50 percent debt. Equity is contributed by the partners in proportion to the cost of separate steam and power facilities. In the coal-fired units case the utility provides 84 percent of the equity. The nuclear plant requires that the utility contribute 92 percent of the total equity. The prices paid by the utility for electricity and by the industry for steam are set so that each partner saves a sufficient amount, as compared to purchase outside the joint venture, to provide the "standard" return (12 percent after-tax on equity for the utility, 20 percent before tax on total investment for industry).

The generation assumptions used in the development of Case C financial results are provided in Table 9. Total capacity and generation numbers in this case are considerably higher than in either Case A or Case B. But the reader should note that the case presented here is extreme: All coal capacity in 1979 and beyond, all nuclear capacity in 1981 and beyond, is constructed by joint ventures. In effect, no new capacity is added to the electric utilities as we known them after 1980.

Combined implementation, Case D

The combined implementation case assumes that industrial power generation replaces all coal-fired capacity due for completion during 1979-80 and all nuclear capacity due for 1981-82. Joint ventures provide the capacity of coal-fired and part of the combined cycle plants due in 1981-85 and nuclear plants scheduled for 1983-85. The capacity and generation impacts of these assumptions are summarized in Table 10.

TABLE 9

Joint-Venture, Dual Purpose, Central Power Stations--Case C, Generation Assumptions

| Year | MW * Joint Venture, Added Coal Capacity | MW Joint Venture, Added Nuclear Capacity | MW Joint Venture, Cummulative Total Capacity | Generation (billions KWH) |
|---|---|---|---|---|
| 1979 | 13,706 | --- | 13,706 | 65.44 |
| 1980 | 12,534 | --- | 26,240 | 122.47 |
| 1981 | 7,572 | 15,887 | 49,699 | 267.93 |
| 1982 | 5,546 | 15,714 | 70,959 | 401.33 |
| 1983 | 6,319 | 17,054 | 94,332 | 548.43 |
| 1984 | 5,411 | 17,399 | 117,142 | 693.34 |
| 1985 | 4,130 | 17,775 | 139,047 | 835.90 |

* MW - Megawatts

TABLE 10

Combined Implementation--Case D,
Industrial Power Generation and Dual Purpose Central Power Stations,
General Assumptions

| Year | MW Industry Capacity Added | Megawats Joint Venture, Capacity Added: Coal | Megawats Joint Venture, Capacity Added: Nuclear | Total Capacity Operational (MW) | Industrial Generation for Own Use (billions KWH) | Industrial Generation for Sale to Utilities (billions KWH) | Joint Venture Generation Sold to Utility (billions KWH) | Total Utility Power Purchased (billions KWH) |
|---|---|---|---|---|---|---|---|---|
| 1979 | 11,659 | -- | -- | 11,659 | 61.05 | 25.76 | -- | 25.76 |
| 1980 | 8,914 | -- | -- | 20,573 | 107.73 | 45.46 | -- | 45.46 |
| 1981 | 12,734 | 6,238 | -- | 39,545 | 174.40 | 73.60 | 28.03 | 101.63 |
| 1982 | 12,239 | 4,761 | -- | 56,545 | 238.47 | 100.65 | 47.75 | 148.40 |
| 1983 | -- | 6,286 | 13,995 | 76,826 | 238.47 | 100.65 | 174.82 | 275.47 |
| 1984 | -- | 6,357 | 14,332 | 97,915 | 238.47 | 100.65 | 303.99 | 404.64 |
| 1985 | -- | 6,162 | 14,614 | 118,691 | 238.47 | 100.65 | 434.09 | 534.74 |

This case represents one of many possible combined implementation services. It is presented here to suggest the order of magnitude of benefits that might be expected if both by-product generation and joint-venture central power stations become a reality.

## Presentation and Analysis of Data

This section presents the projected financial and economic impact of the alternative power generation cases. Effects on the electric utilities are simulated in the financial model by altering the level and time pattern of demand to correspond to the assumed pattern of investment and generation taken by industry and joint ventures. Overall system results are developed by combining the utility financial projections with forecast values of capital expenditure, financing, and generation for industry and the joint ventures.

### Capital expenditures

Substantial savings in the investment required to support growth in demand for electricity are realized in each of the alternative generation cases. Comparative data for 1976, 1980, 1985, and the annual average of the 1976-85 results are shown in Table 11.

In the base case, industry is assumed to follow the historical trend of a declining proportion of industry generation to industry use. Utility capital expenditures increase from $18.4 billion in 1976 to 42.5 during 1985, an average annual outlay of approximately $30 billion. Total investment in the generating plant by utilities, industry, and joint ventures for each alternative is compared to these base case expenditures to determine savings. The magnitude and timing of the differences depends on the assumed pattern of industry and joint venture investment in generating plants.

Under Case A assumptions, industry generates by-product and condensing power only for its own use. During the 1976-85 period, industry invests an annual average of $1.4 billion in generating plants and utilities invest $3.5

TABLE 11

Capital Expenditure Comparisons
( $\$ \times 10^6$ )

| | 1976 | 1980 | 1985 | Average Annual Result 1976 - 1985 |
|---|---|---|---|---|
| Base Case--Utility | 18,368 | 29,611 | 42,453 | 30,528 |
| Case A: Utility | 16,195 | 24,418 | 39,918 | 26,966 |
| Industry | --- | 4,146 | 866 | 1,420 |
| Total | 16,195 | 28,564 | 40,784 | 28,386 |
| Savings Compared to Base | 2,173 | 1,047 | 1,669 | 2,142 |
| Total Utility Compared to Base | 2,173 | 5,193 | 2,535 | 3,562 |
| Case B: Utility | 15,090 | 21,131 | 39,230 | 25,225 |
| Industry | -- | 5,607 | 1,171 | 1,920 |
| Total | 15,090 | 26,738 | 40,301 | 27,145 |
| Savings Compared to Base | 3,278 | 2,873 | 2,152 | 3,383 |
| Total Utility Compared to Base | 3,278 | 8,480 | 3,223 | 5,303 |
| Case C: Utility | 17,273 | 16,196 | 20,972 | 17,488 |
| Joint Venture | -- | 5,914 | 17,122 | 8,732 |
| Total | 17,273 | 22,110 | 38,094 | 26,220 |
| Savings Compared to Base | 1,095 | 7,501 | 4,359 | 4,308 |
| Total Utility Compared to Base | 1,095 | 13,415 | 21,481 | 13,040 |
| Case D: Utility | 17,844 | 16,228 | 25,371 | 19,038 |
| Joint Venture | -- | -- | 15,982 | 4,992 |
| Industry | -- | 2,411 | -- | 1,289 |
| Total | 17,844 | 18,639 | 41,353 | 25,319 |
| Savings Compared to Base | 524 | 10,972 | 1,100 | 5,209 |
| Total Utility Compared to Base | 524 | 23,383 | 17,082 | 11,490 |

billion less than in the base case for a net savings of $2.1 billion. Because the major portion of industry investment is assumed to take place during 1978-80, utility investment savings are greatest during 1976-80. In Case B, industry investment increases to an annual average of $1.9 billion, and power generated in excess of industry needs is sold to utilities. Utilities save an average of $5.3 billion each year, and the net average annual savings is $3.4 billion. As in Case A, higher savings are realized during 1976-80 than during 1981-85.

The joint-venture, dual purpose central power stations assumed in Case C yield net capital expenditure savings of $4.3 billion annually. Utility outlays are reduced an average of $13 billion per year. But because the lead time on generating joint-venture activity is longer than that for the industry generation envisioned in Cases A and B, the distribution of savings shifts and highest benefits are realized during 1980-83.

Case D, the combined implementation alternative, yields the highest average annual capital savings, $5.2 billion. Industry investment is assumed to occur during 1979-82 and joint venture investment occurs during 1981-85. Greatest net savings are realized in the 1979-82 period, with peak savings of $11.0 billion during 1980. The direct impact on utility investment is a reduction averaging $11.5 billion annually.

External financing

Projected utility external financing requirements in the base case average $22.7 billion annually, approximately two-thirds of the average annual capital expenditures. About 60 percent of the external financing is debt, 18 percent preferred stock, and 22 percent common stock, to maintain the desired capital structure proportions. These ratios are roughly the same for all cases.

Reductions in required external financing for the alternative cases follow the pattern of capital expenditure savings as shown in Table 12. In Case A, utility financing reductions of $2.8 billion and industry financing requirements of $1.1 billion yield system savings of $1.7 billion per year. Utility financing reductions of $4.1 billion and industry requirements of $1.4 billion provide overall annual savings of $2.7 billion in Case B. As was the case with capital expenditures, reductions during 1976-80 are greatest.

Financing for dual-purpose central power stations is calculated to average $4.3 billion annually. Net reduction in the funds required to support industry generation averages $2.9 billion. The savings are greatest, however, during 1980-83 as was the case for capital expenditures. In Case D. industry requires an average of $1.0 billion per year in external financing, and joint ventures need $2.5 billion annually. Reductions in utility requirements of $7.4 billion yield average annual net reductions of $3.9 billion. In this case the distribution of external financing reductions is concentrated in the 1979-82 period.

Rates

In general, the proposed generation alternatives result in lower utility rates during 1976-85. Average rates for all customer classes for an average year are lower than the base case by 0.7 percent for Case A, 2.9 percent for Case B, 6.0 percent for Case C, and 5.0 percent for Case D, as given in Table 13. The ability to lower rates while still providing the required returns to suppliers of capital reflects investment and operating efficiencies.

The effect the alternative cases have on rates in each customer class reflects the cost allocation procedure described in an earlier section. Average residential rates decline 4.6 percent in Case A, 6.8 percent in Case B, and 8.0 percent in Cases C and D. Industrial rate decreases are considerably more modest: 1.4 percent in Case A, 2.7 percent in Case B, 0.3 percent in Case C, and 2.0 percent in Case D.

TABLE 12

External Financing Comparison
(\$ x $10^6$)

| | 1976 | 1980 | 1985 | Average Annual Result 1976 - 1985 |
|---|---|---|---|---|
| Base Case--Utility | 15,581 | 23,203 | 28,464 | 22,732 |
| Case A: Utility | 13,580 | 17,588 | 27,670 | 19,962 |
| Industry* | -- | 3,110 | 650 | 1,065 |
| Total | 13,580 | 20,698 | 28,320 | 21,027 |
| Savings Compared to Base | 2,001 | 2,505 | 144 | 1,705 |
| Total Utility Compared to Base | 2,001 | 5,615 | 794 | 2,770 |
| Case B: Utility | 12,565 | 13,944 | 27,873 | 18,597 |
| Industry | -- | 4,205 | 878 | 1,440 |
| Total | 12,565 | 18,149 | 28,751 | 20,037 |
| Savings Compared to Base | 3,016 | 5,054 | (287) | 2,695 |
| Total Utility Compared to Base | 3,016 | 9,259 | 591 | 4,135 |
| Case C: Utility | 14,593 | 15,497 | 18,820 | 15,426 |
| Joint Venture | -- | 2,957 | 8,561 | 4,366 |
| Total | 14,593 | 18,454 | 27,381 | 19,792 |
| Savings Compared to Base | 988 | 4,749 | 1,083 | 2,940 |
| Total Utility Compared to Base | 988 | 7,706 | 9,644 | 7,306 |
| Case D: Utility | 15,123 | 16,776 | 21,067 | 15,343 |
| Joint Venture | -- | -- | 7,991 | 2,496 |
| Industry | -- | 1,808 | -- | 967 |
| Total | 15,123 | 18,584 | 29,058 | 18,806 |
| Savings Compared to Base | 458 | 4,619 | (594) | 3,926 |
| Total Utility Compared to Base | 458 | 6,427 | 7,397 | 7,389 |

*Industry is assumed to externally finance the same proportion of capital expenditure as do the utilities.

TABLE 13

Utility Power Rate Comparison

| | Residential | | | | Commercial | | | |
|---|---|---|---|---|---|---|---|---|
| | 1976 | 1980 | 1985 | Average Year | 1976 | 1980 | 1985 | Average Year |
| Base Case: ¢/KWH | 3.62 | 4.79 | 6.21 | 5.03 | 3.49 | 4.70 | 6.16 | 4.84 |
| 1973¢/KWH | 2.78 | 2.80 | 2.75 | 2.81 | 2.68 | 2.75 | 2.73 | 2.76 |
| Case A: ¢/KWH | 3.61 | 4.60 | 6.09 | 4.80 | 3.47 | 4.50 | 6.03 | 4.71 |
| 1973¢/KWH | 2.77 | 2.69 | 2.70 | 2.70 | 2.67 | 2.63 | 2.67 | 2.64 |
| Percentage change from Base Case (nominal) | (0.2) | (4.0) | (1.9) | (4.6) | (0.6) | (4.2) | (2.1) | (2.7) |
| Case B: ¢/KWH | 3.60 | 4.46 | 5.93 | 4.69 | 3.47 | 4.35 | 5.85 | 4.58 |
| 1973¢/KWH | 2.77 | 2.61 | 2.63 | 2.61 | 2.66 | 2.54 | 2.59 | 2.54 |
| Percentage change from Base Case | (0.5) | (6.9) | (4.5) | (6.8) | (0.6) | (7.4) | (5.0) | (5.4) |
| Case C: ¢/KWH | 3.59 | 4.60 | 5.51 | 4.63 | 3.52 | 4.49 | 5.37 | 4.52 |
| 1973¢/KWH | 2.76 | 2.69 | 2.44 | 2.69 | 2.70 | 2.63 | 2.38 | 2.62 |
| Percentage change from Base Case | (0.8) | (4.0) | (11.3) | (8.0) | 0.9 | (4.5) | (12.8) | (6.6) |
| Case D: ¢/KWH | 3.59 | 4.60 | 5.51 | 4.63 | 3.52 | 4.49 | 5.44 | 4.54 |
| 1963¢/KWH | 2.76 | 2.69 | 2.44 | 2.69 | 2.70 | 2.63 | 2.41 | 2.63 |
| Percentage change from Base Case | (0.8) | (4.0) | (11.3) | (8.0) | 0.9 | (4.5) | (11.7) | (6.2) |

TABLE 13 Continued

Utility Power Rate Comparison

| | Industrial | | | | Other | | | |
|---|---|---|---|---|---|---|---|---|
| | 1976 | 1980 | 1985 | Average Year | 1976 | 1980 | 1985 | Average Year |
| Base Case: ¢/KWH | 2.13 | 2.91 | 3.61 | 2.93 | 3.16 | 4.28 | 5.57 | 4.40 |
| 1973¢/KWH | 1.64 | 1.70 | 1.60 | 1.70 | 2.43 | 2.50 | 2.47 | 2.51 |
| Case A: ¢/KWH | 2.13 | 2.84 | 3.58 | 2.89 | 3.15 | 4.11 | 5.47 | 4.28 |
| 1973¢/KWH | 1.63 | 1.66 | 1.58 | 1.66 | 2.42 | 2.40 | 2.42 | 2.41 |
| Percentage change from Base Case | 0 | (2.4) | (0.8) | (1.4) | (0.3) | (4.0) | (1.8) | (2.7) |
| Case B: ¢/KWH | 2.13 | 2.78 | 3.52 | 2.85 | 3.15 | 3.98 | 5.31 | 4.18 |
| 1973¢/KWH | 1.63 | 1.63 | 1.56 | 1.63 | 2.42 | 2.33 | 2.35 | 2.33 |
| Percentage change from Base Case | 0 | (4.5) | (2.5) | (2.7) | (0.3) | (7.0) | (4.7) | (5.0) |
| Case C: ¢/KWH | 2.13 | 2.86 | 3.64 | 2.92 | 3.18 | 4.11 | 4.97 | 4.14 |
| 1973¢/KWH | 1.64 | 1.67 | 1.61 | 1.68 | 2.45 | 2.40 | 2.20 | 2.40 |
| Percentage change from Base Case | 0 | (1.7) | 0.8 | (0.3) | 0.6 | (4.0) | (10.8) | (5.9) |
| Case D: ¢/KWH | 2.13 | 2.83 | 3.52 | 2.87 | 3.18 | 4.10 | 4.94 | 4.14 |
| 1973¢/KWH | 1.64 | 1.65 | 1.56 | 1.65 | 2.45 | 2.40 | 2.19 | 2.40 |
| Percentage change from Base Case | 0 | (6.2) | (2.5) | (2.0) | 0.6 | (4.2) | (11.3) | (5.9) |

TABLE 13 Continued

Utility Power Rate Comparison

| | Average | | | |
|---|---|---|---|---|
| | 1976 | 1980 | 1985 | Average Year |
| Base Case: ¢/KWH | 2.99 | 4.06 | 5.21 | 4.20 |
| 1973¢/KWH | 2.30 | 2.37 | 2.31 | 2.38 |
| Case A: ¢/KWH | 2.98 | 4.06 | 5.34 | 4.17 |
| 1973¢/KWH | 2.29 | 2.37 | 2.36 | 2.41 |
| Percentage change from Base Case | (0.3) | 0 | 2.5 | (0.7) |
| Case B: ¢/KWH | 2.98 | 3.94 | 5.20 | 4.08 |
| 1973¢/KWH | 2.29 | 2.30 | 2.30 | 2.30 |
| Percentage change from Base Case | (0.3) | (3.0) | (0.2) | (2.9) |
| Case C: ¢/KWH | 2.99 | 3.91 | 4.76 | 3.95 |
| 1973¢/KWH | 2.30 | 2.29 | 2.11 | 2.29 |
| Percentage change from Base Case | 0 | (3.7) | (8.6) | (6.0) |
| Case D: ¢/KWH | 2.99 | 3.95 | 4.83 | 3.99 |
| 1973¢/KWH | 2.30 | 2.31 | 2.14 | 2.31 |
| Percentage change from Base Case | 0 | (7.6) | (7.3) | (5.0) |

The distribution of rate decreases during the 1976-85 period reflects the assumed pattern of industry and joint venture capital expenditures in each alternative case. Cases A and B rate decreases are greater in the early years, while decreases in Cases C and D are realized later in the period.

Monthly residential bill

The impact of time and the alternative generation cases on the average residential monthly bill is given in Table 14. The growth rate of average bill size is lower than the rate of inflation in all cases, including the base case. As compared to the base case, Case A reduces the average bill by 2.6 percent. The reduction is 4.9 percent for Case B, and 6.6 percent for Cases C and D.

## Conclusions

The principal economic and financial benefits of by-product power generation and joint-venture central power stations are (1) national savings in labor, capital, and fuel used, (2) reductions in the utilities' requirements for capital raised in the financial markets, and (3) reduced consumer costs of electricity.

Over the period 1976 to 1985 savings in capital required to generate electricity vary from $2 billion per year in Case A to $5 billion per year in Case D. Accumulated savings over the period 1976 to 1985 would be $20 billion to $50 billion depending on the case selected. This means that resources valued at $20 to $50 billion would be freed for uses in other parts of the economy. The by-product power generation and joint-venture control power stations would thus result in a significant increase in the productivity of the nation's resources.

The major problem facing the investor-owned utilities today is raising capital. That problem would be substantially eased under the by-product and joint-venture options. Over the period 1976 to 1985 investor-owned utilities would be required to raise externally an average of $22.7 billion in the base

TABLE 14

Monthly Residential Bill (Average)
($)

| | 1976 | 1980 | 1985 | Average |
|---|---|---|---|---|
| Base Case | 23.40 | 37.44 | 54.54 | 39.75 |
| Case A | 23.32 | 35.97 | 53.52 | 38.70 |
| Change from Base Case ($) | (0.08) | (1.47) | (1.02) | (1.05)* |
| Change from Base Case (%) | (0.3) | (3.9) | (1.9) | (2.6) |
| Case B | 23.28 | 34.86 | 52.07 | 37.82 |
| Change from Base Case ($) | (0.14) | (2.58) | (2.47) | (1.93) |
| Change from Base Case (%) | (0.5) | (6.9) | (4.5) | (4.9) |
| Case C | 23.19 | 35.33 | 48.42 | 37.14 |
| Change from Base Case ($) | (0.21) | (1.51) | (6.12) | (2.61) |
| Change from Base Case (%) | (0.9) | (4.0) | (11.2) | (6.6) |
| Case D | 23.20 | 35.93 | 48.35 | 37.13 |
| Change from Base Case ($) | (0.20) | (1.51) | (6.19) | (2.62) |
| Change from Base Case (%) | (0.8) | (4.0) | (11.3) | (6.6) |

*Because the growth pattern in number of customers differs from the growth in residential demand, the case-to-case percentage change in the average monthly residential bill shown here is not the same as the percentage change in average residential rates as given in Table 13.

case. In Case A this would fall to $20.0 billion and in Case B $18.6 billion--reductions of $2.7 billion and $4.1 billion respectively. In Case C the utilities must raise externally an average of $15.4 billion per year on their own and $4.4 billion with their industrial partners for a total of $19.8 billion; $2.8 billion less than they must raise on their own in the base case. In Case D the utilities must raise externally $15.3 billion on their own and $2.5 billion in joint ventures for a total of $17.8 billion, $4.9 billion less than they must raise on their own in the base case.

Customers of investor-owned electric utilities will pay less for electricity because of the savings in capital, labor and fuel. Taking all electricity consumers together--residential, commercial, and industrial--we find that consumer savings are 2.9 percent in Case B, 6.0 percent in Case C, and 5.0 percent in Case D. Consumer savings are only 0.7 percent in Case A because none of the new efficiently produced electricity is consumed through the utility system. The benefits in Case A go largely to the industrial firms that have chosen to generate their own electricity.

Residential rates are lower by 4.6 percent in Case A, 6.8 percent in Case B, and 8.0 percent in Cases C and D. Under the base case the residential consumer's average bill (in current dollars) would be running at an average of $39.75 over the period 1976 to 1985.

In Case A it would be $38.70, Case B $37.82, Case C $37.14, and Case D $37.13. Thus, in Cases C and D the average residential consumer would save about $2.60 per month, or $31.20 per year on his electric bill.

The consumer savings shown do not include the effect of the lower rates of return on capital which are required when external financial demands are reduced. They also do not take into account the fact that consumers will use more electricity at lower rates. Thus, the consumer savings computed here reflects only one of the three sources of savings. Further research is necessary to estimate the contribution of lower rates of return and price elasticity on consumer savings.

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