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ENERGY PRODUCTION AND RESIDENTIAL HEATING: TAXATION, SUBSIDIES, AND COMPARATIVE COSTS

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FOREWORD

The Ohio River Basin Energy Study (ORBES) is an interdisciplinary, multi-university inquiry into the environmental, economic, and social impacts of energy facility development in a major portion of the Ohio River Basin. The study was initiated by the U.S. Environmental Protection Agency in 1976 in response to a directive from the U.S. Senate Appropriations Committee.

Most of the ORBES research was conducted by a group of faculty members at the University of Illinois, Indiana University, the University of Kentucky, the University of Louisville, The Ohio State University, the University of Pittsburgh, Purdue University, and West Virginia University. In a few instances, the necessary expertise was found at other universities or independent research organizations.

This report is one of a series produced in support of the overall ORBES assessment. For a summary of the entire study, see Ohio River Basin Energy Study (ORBES): Main Report, by the ORBES Core Team, also being published by the U.S. Environmental Protection Agency.

ABSTRACT

This analysis was undertaken in support of the Ohio River Basin Energy Study. It is intended to clarify the effect of economic incentives upon private and public decisions affecting energy production and use. It focuses upon the economics of coal and nuclear power generation, and upon the economics of household space and water heating. The impact of tax incentives is important in each case, and the general problem of renewable versus conventional energy use is partially addressed.

Southern Indiana is taken as a representative ORBES area. A simulation model of utility economics relevant to power plant costs examines the construction and operating periods of coal and nuclear plants. The major findings are:

1. The amortized, annual equivalent tax liability on revenue from new coal and nuclear plants is negative.
2. The timing of tax credits and deductions promotes the premature construction of new plants and the premature retirement of existing plants.
3. Because nuclear power is more capital intensive than coal power, it receives a tax subsidy nearly three times greater than coal generation.
4. For utility analysis of future generating costs, coal power appears to be slightly less costly to the utility when costs are conventionally expressed as after-tax, levelized, annual costs over the plant's operating life.
5. As an illustration: in 1983 dollars, the cost of nuclear power may be 7.3 ¢/kWh with a 3.7 ¢/kWh tax subsidy; coal generation may cost 6.3 ¢/kWh with a 1.3 ¢/kWh subsidy.
6. Higher general inflation and interest rates will increase nuclear cost more than coal cost, and increase the nuclear subsidy more than the coal subsidy.
7. In the absence of corporate income tax subsidies, utilities in the ORBES region would find coal generation less costly than nuclear power.

Southern Indiana is also the locus of the comparative analyses of home space and water heating costs. Several possible future cases of real energy price inflation, general inflation, and interest rates are examined for a representative owner-occupied new home. The major conclusions are:

1. Natural gas space and water heating is usually less costly than any other alternative.

2. Electric resistance space and water heating is always the most expensive mode when costs are expressed on an annual basis.

3. Installation costs for electric resistance space and water heating are less than those of other systems.

4. Solar heating receives considerable tax subsidy through the Indiana property tax exemption and the Federal personal income tax interest deductions and solar tax credit.

5. With real energy price inflation interacting with general inflation, solar, wood, and heat pump systems become less costly than conventional oil heat and electric resistance space and water heat.

6. If natural gas prices reach parity with oil on a Btu basis in 5 years in an economic environment of high inflation, interest rates, and energy price growth, then a solar/gas space heating system is the least costly.

ACKNOWLEDGEMENT

We wish to acknowledge and thank those persons with the Indiana Public Service Commission, Public Service of Indiana, the ORBES group, the Environmental Protection Agency, various contractors, and interested citizens, all for their assistance, patience, and interest.

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LIST OF ABBREVIATIONS

Btu -- British thermal unit(s)

CEC -- California Energy Commission

kWh -- Kilowatt-hour(s)

MBtu -- Millions of British thermal units

MWe -- Megawatts (electric)

ORBES -- Ohio River Basin Energy Study

PSI -- Public Service Indiana, a private electric utility corporation

SIMCON -- A computer simulation model of power plant construction, operation, and decommissioning (for a nuclear plant) as it effects utility economics

TMI -- Three Mile Island Nuclear Power Station, Harrisburg, Pennsylvania

SECTION 1

INTRODUCTION

This study explores a segment of the economic incentives which influence energy production and use decisions in the Ohio River Basin. A particular sub-region within the Ohio River Basin Energy Study (ORBES) region is used as a locus for analysis. The decision to use a specific area is based upon the availability of specific data, permitting both analysts and reviewers to examine these complex subjects in a specific setting. Of course the virtue of specificity in analysis and assumptions carries a parallel defect: generalization to the entire ORBES region is difficult without careful consideration of the assumptions, methods, and conclusions of the analysis.

Southern Indiana is used as the representative area for several reasons: (1) It is an area where coal and nuclear power are believed to be economically competitive; (2) If Alaskan natural gas is delivered to an Illinois terminus, it will probably be available to southern Indiana; (3) It was anticipated that each of the renewable residential energy sources (solar water heating and wood space heating) might be competitive; and (4) Residential electric heating has been increasing rapidly. Phrasing these points more generally, we think southern Indiana shows the interaction of all the major economic influences which affect utility decisions on coal versus nuclear power and residential homeowners' decisions on space and water heating. Discussion with ORBES Core Team members confirmed our opinion on these points.

Two types of decisions are examined in the study. The first decision area is the electric utility choice between coal and nuclear power. The second decision area is the homeowner's choice of space and water heating systems. A common dimension to both types of decisions is the tax system and its influence on comparative costs.

For electric utilities, nuclear power has been widely believed to be less costly than coal power for electric utilities and their customers. We examine a representative area in southern Indiana to determine if this widely believed conclusion is appropriate to current circumstances.

The means by which this problem is addressed is a simulation by computer of the economic aspects of hypothetical coal and nuclear power plants in the southern Indiana area. The model for the nuclear plant[1/] examines 110

1/ It is described more fully in Duane Chapman, "Nuclear Economics: Taxation, Fuel Cost, and Decommissioning," prepared for the California Energy Commission. It is available from that Commission of from the author.

variables which have different annual values over part or all of a 47-year period of construction, operation, and decommissioning. Fifty-five other variables have single values. The coal plant model is similar. Occasionally these models are referred to as SIMCON, an acronym taken from the words "simulation by computer".

There are two methods of price determination utilized in the analysis. The first is a behavioral representation of normal regulatory policy. Revenues each year are the sum of fuel expense, operating cost, tax allowance, and return to capital. As rate base depreciates, return to capital declines, and this partially offsets rising fuel and operating costs.

The second method of price determination is analogous to the concept of "levelized" cost. A price is found which, if inflated each year at a general inflation rate, would exactly pay all costs, taxes, and the allowed return to capital.

An integral part of this model is its examination of the tax effects of a new plant on the economics of the utility. Both Indiana and Federal provisions are examined. The most significant elements of income tax treatment relate to the investment tax credit, the allowance for funds used during construction, interest deductions, accelerated depreciation, and arbitrary short tax lives. In the Appendix, these provisions are summarized as they affect utility economics.

The analysis here finds that these provisions have a crucial influence on the coal/nuclear choice, that they have considerable impact upon customer costs, and that they influence the timing of new plant construction and old plant retirement. Increasing inflation and interest rates magnify the tax effects in each case.

The homeowner's choice of mode of space and water heating for a new home is complex. Of course all energy prices are rising, and at unpredictable rates. Utility rate structures are being revised to eliminate promotional discounts for high quantity consumption.

The system with lowest installation cost may not be the system with least total annual cost.

We address the problem by examining all (or nearly all) of the economic factors affecting annual costs. There are initial costs and annual mortgage payments, maintenance expense, fuel cost and performance efficiency, Indiana and Federal personal income tax deductions, the Federal solar energy tax credit, and property and sales taxes.

Conventional systems considered are oil, natural gas, electric resistance, and electric heat pump. Renewable resource systems studied are wood burning and solar space and water heating.

In the ORBES area studied, growth in electric heating customers is exceeding total customer growth. This increases the significance of examining both initial and annual system cost, and the tax subsidies influencing each system.

The comparability of personal and corporate tax incentives is limited. In the narrow context of this analysis, these two kinds of tax subsidies are compared to determine their impact upon customer cost and total cost.

This latter concept of total cost approaches the meaning of social cost. When calculating tax subsidies, we look at part of the "hidden" cost of an energy system. To the extent that the subsidy analysis is comprehensive and accurate, subsidies -- in combination with actual customer cost -- indicate the costs of particular energy systems for the national economy.

SECTION 2

UTILITY COST: COAL AND NUCLEAR POWER

Assumptions

In 1976, the ORBES region had 93,000 MWe of generating capacity. Two percent of this capacity was nuclear power, and 88% was coal capacity. However, according to the ORBES inventory of utility plans for additional capacity, nuclear power would constitute 9% of a 126,000 MWe total capacity in 1986. Coal would be 83% of the total. Growth in nuclear power generation, then, equals 20% of the utilities' planned growth in region capacity1/.

To a considerable degree, growth in nuclear power has been predicated upon the apparent economic advantage to the utility which is believed to result from nuclear power generation. Table 1 shows two industry cost estimates, one before and one after the Three Mile Island (TMI) accident.

Brandfon's analysis is post-TMI. His cost basis is levelized cost during the operating period with overall inflation assumed to be 6% per year. In other words, he concludes that, if 8.9¢ were charged for each kWh sold during 1990-2020, then all costs would be met with no excess profit.

The Rossin-Rieck paper appeared several months before TMI, and is on a different basis. It is in constant 1977 dollars. This means that any overall inflation rate applied to 3.5 ¢/kWh in 1977 dollars would exactly meet all costs.

Rossin-Rieck concludes coal power is 20% more expensive, while Brandfon's post-TMI analysis finds nuclear power with a 16% margin.

Non-industry analysts have concluded that the nuclear margin is less, or non-existent. Charles Komanoff and Ronald Knecht are two such analysts2/. However, Table 1 gives a good representation of industry analysis and its finding that nuclear power is less costly.

1/ Steven D. Jansen, "Electrical Generating Unit Inventory 1976-1986," prepared for ORBES, November, 1978, pp. 5, 7. This report presents a comprehensive inventory of utility capacity plans in the region.
2/ Charles Komanoff, "A Comparison of Nuclear and Coal Costs," Testimony, New Jersey Board of Public Utilities, October 9, 1978; Ronald L. Knecht, "Power Generating Economics and Planning," Wisconsin Public Service Commission, December 28, 1978.

TABLE 1. RECENT COAL AND NUCLEAR POWER COST ESTIMATES
INDUSTRY SOURCES
(¢/kWh)

Author(s):	W.M. Brandfon	A.D. Rossin and T.A. Rieck
Affiliation:	Sargent & Lundy Engineers; Atomic Industrial Forum	Commonwealth Edison Company; American Nuclear Society
Date of pub.:	July 12, 1979	August 18, 1978
Cost basis:	levelized cost, 1990-2020	levelized cost, 1977 dollars
Nuclear Generation (¢/kWh)		
O, M, I, D	0.6	0.2
Fuel	2.5	0.7
Capital Charges	5.8	2.6
Total	8.9	3.5
Coal Generation (¢/kWh)		
O, M	1.2	0.5
Fuel	5.0	1.3
Capital Charges	4.1	2.4
Total	10.3	4.2

Note: O, M, I, D represent, respectively, operations, maintenance, insurance, and decommissioning cost.

Both analyses conclude high sulfur coal with scrubbers is the least costly coal/oil alternative which meets air standards, and this is the basis for both coal estimates. Sources are William W. Brandfon, "Comparative Costs of Coal and Nuclear Electricity Generation," Oversight Hearings on Nuclear Economics, Hearings, U.S. House Interior Committee, Subcommittee on Energy and the Environment, July 12. 1979; A.D. Rossin and T.A. Rieck, "Economics of Nuclear Power," Science, vol. 201, 18 August 1978, pp. 582-589.

TABLE 2. ASSUMPTIONS IN CORNELL COMPARATIVE COST AND TAX SUBSIDY ANALYSIS

1. Capital structure for new plants (Refs. 5, 6, 7)

   50% debt at 9.5% interest

   40% common stock equity at 14.7% after-tax return

   10% preferred stock equity at 9.5% after-tax return

2. Construction period

   Nuclear power: 10 years[a/]

   Coal power: 5 years (Ref. 7, p. 10)

3. Capacity, electrical

   Nuclear plant: 1,000 MWe

   Coal plant: 650 MWe

4. Capacity factor

   Nuclear plant: rises, stabilizes, and declines. Average is 62% (Ref. 2, pp. 29-30)

   Coal plant: 60% (Ref. 6)

5. Operating life

   Nuclear plant: 30 years (Refs. 1, 2)

   Coal plant: 35 years (Ref. 4, p. 81)

6. Fuel cost

   Nuclear plant: 0.8 ¢/kWh in 1978, in 1978 dollars (see text and Table 3)

   Coal plant: $1.06/MBtu in 1978 in 1978 dollars (Ref. 7, p. 34), and 10,600 Btu/kWh[b/]

7. Operations, maintenance, insurance, and administration cost

   Nuclear plant: $40 million in 1978, in 1978 dollars (Ref. 2, p. 31)

   Coal plant: 6.45 mills/kWh in 1978, in 1978 dollars (Ref. 6)

8. Capital cost

   Nuclear plant: $1,047/kW in 1978, in 1978 dollars (Ref. 2, p. 19)

   Coal plant, incl. scrubber: $700/kW in 1978, in 1978 dollars (Ref. 6)

(continued)

9. Inflation and escalation

Note: Specific escalation equals the product of overall inflation and real inflation. E.g., for nuclear investment, (1.[illegible])*(1.[illegible]) = 1.14.

General: 7%, from 1978 through the entire period[c]

Nuclear investment: 6.5% real inflation, 1978 through [illegible][d]

Coal investment: 1.9% real inflation, 1979 through 19[illegible][e]

Nuclear fuel: equivalent to 0.8% real inflation, [illegible] onward[f]

Coal fuel: 2.8% real inflation, 1978 onward[g]

Nuclear O&M: equivalent to -2.3% real inflation after 19[illegible][h]

Coal O&M: -1.9% real inflation after 1978[i]

10. State and federal taxation[j]

Federal corporate income tax rate: 46%

Indiana corporate income tax rate: 3%

Indiana gross receipts tax: 1.5% in 1978, declining .05% annually

Indiana property tax: 1%

Footnotes, Table 2

a/ Wilfrid Comtois, "Power Plant Construction Schedules, Escalation, and Interest During Construction," presented at the American Power Conference, April 21, 1976.

The construction period is not intended to give the full length of the planning and approval process, but to represent the period in which significant expenditures are experienced.

b/ Suggested by utility analysts at Ohio River Basin Energy Study Meeting, Lexington, Kentucky, October 5, 1979.

c/ A year ago, a 7% general inflation assumption was common. However, twelve-month inflation in the Consumer Price Index is currently an annual 11.5%, and inflation in the Gross National Product implicit price deflator is an annual 8.6%. Both appear to be rising.

d/ California Energy Commission analysis shows nuclear plant costs increased 22% per year, 1971-76. A 14% escalation is 2/3 of this. (See also Ref. 2, p. 19.) The product of general inflation (7%) and real inflation (6.5%) defines actual escalation (14%). It is of interest to note that no new plants have been ordered for use in the United States since 1976.

(continued)

e/ In Ronald Knecht, "Review and Critique of California Electricity Generation Methods Assessment Final Report," CEC, 1977, Knecht concluded that a 9% escalation rate was appropriate for coal plants. This is probably lower than actual experience in the past two years. Escalation (1.09) = overall inflation (1.07) * real inflation (1.019).

f/ This inflation assumption for nuclear fuel is reasonable in terms of the past year where there has been little overall increase. In the early 1970s, escalation in U_3O_8 cost was spectacular, averaging 23% per year from 1973 to 1977. However, the actual market price has fallen from $19.75/lb on 1/1/77 to $18.05/lb on 1/1/79. See text and Table 3.

g/ Actual inflation for PSI has been 15% annually (Ref. 7, pp. 34-35). We assume 2/3 of this, or 10% annually. The real inflation rate is 2.8%. (I.e., 1.028 * 1.070 = 1.100.)

h/ See Ref. 2, p. 31.

i/ See Knecht, "Review and Critique," op. cit.

j/ See our note for the 5 October 1979 ORBES meeting, "Federal Income Tax Provisions Affecting Nuclear Power." It is included as Appendix A to this report. Differences between Indiana and IRS regulations and between coal and nuclear power are noted there.

References, Table 2

1. K.B. Cady and A.C. Hui, "NUFUEL - A Computer Code for Calculating the Nuclear Fuel Cycle Cost of a Light Water Reactor," Cornell University, August, 1978.

2. Duane Chapman, "Nuclear Economics: Taxation, Fuel Cost, and Decommissioning," draft final report submitted to the California Energy Commission (CEC), October 29, 1979 (revised).

3. Ronald Knecht, "Testimony on Power Generating Economics and Planning," Wisconsin Public Service Commission, Northern States Power Company Application for Tyrone Nuclear Unit, December 28, 1978.

4. Ron Knecht, et al., "Comparative Cost Analysis (Revised)," Supporting Document No. 9, California Energy Commission, Spring, 1978.

5. Ben Koebel, Chief Accountant, Indiana Public Service Commission, letter to Kathleen Cole, August 29, 1979.

6. James H. Pennington, Vice President - Financial Operations, Public Service Indiana, letter to Duane Chapman, September 10, 1979.

7. Public Service Indiana, Annual Report.

TABLE 3. NUCLEAR FUEL CYCLE ASSUMPTIONS

Fuel cycle activity	Price mid-1979	Real inflation rate	Equilibrium annual quantities	Lead (+) or lag (-) years from first use
uranium ore	\$43.60/lb U_3O_8	1%	456,133 lb U_3O_8	+3
conversion	\$4.41/kg U	0%	173,300 kg U	+3
enrichment	\$89.02/kg SWU	1%	114,127 kg SWU	+2
fabrication	\$100.00/kg U	0%	27,143 kg U	+1
spent fuel transportation	\$16.00/kg U	1%	27,143 kg U	-3
waste disposal	\$250.00/kg U	0%	27,143 kg U	-3

Note: The inflation rates in this table interact with the overall inflation rate as in Table 2. The product of general overall inflation and real inflation defines the specific rate. For example, for uranium ore, 1.07*1.01 = 1.08. The specific rates are commonly referred to as escalation rates. Waste fuel disposal is the subject of specific analysis in a later section. General sources of information are the U.S. Energy Information Administration's Monthly Energy Review, and its Annual Report to Congress, and Cady and Hui, "NUFUEL".

Tables 2 and 3 show the basic assumptions employed by us in our examination of costs in southern Indiana.

Table 2 gives cost, finance, and operating assumptions for coal and nuclear power. The reference numbers (i.e., Refs. 1-5) refer to the publications listed after the footnotes to Table 2.

Nuclear fuel cost is particularly difficult to represent in the format utilized in Table 2. The value of 0.8 ¢/kWh (item 6, Table 2) is derived from the assumptions given in Table 3. The SIMCON model includes a representation of three methods of fuel cost calculation. These three methods are (1) actual current cash expenditures, (2) batch amortization for net income purposes, in which expected disposal costs are recognized as each batch of fuel is used, and (3) batch amortization for tax purposes, which amortizes acquisition cost as each batch is used in each year, but charges disposal costs as incurred. The 0.8 ¢/kWh value is based upon actual cash expenditures during equilibrium operations1/.

Annual Equivalent Cost

As described in the Introduction, we calculate generating costs in two ways. The first approach defines a constant real price. This constant real price is escalated at the overall inflation rate. The second approach defines a price pattern based upon conventional regulatory methods. Here, price is determined by rate base, return to capital, and fuel and operating costs.

Both methods are used in Figures 1 and 2 for the representative coal and nuclear plants.

The constant real price curve is similarly shaped for the nuclear and coal facilities. For each, price increases 7% per year.

However, the rate base method gives different patterns for coal and nuclear power. For coal, the curve is concave throughout. Fuel cost is a large and growing component of total cost. In 1984 (the first year of the coal plant), fuel cost is 40% of total allowed cost. In the succeeding years, fuel cost escalates at 10% annually, while rate base deterioration causes return to capital to decline. As a consequence, by 2019 fuel cost has become 92% of total allowed cost.

In contrast, nuclear power is more capital intensive. Fuel cost is a lower fraction of total allowed cost in every year. In addition, nuclear fuel cost is presumed to escalate at 7.8% annually, less than coal escalation. As a consequence, rising fuel cost is offset by falling return to the

1/ See Chapman, "Nuclear Economics," pp. 23-29. The three fuel cost accounting methods are described there. However, the data in Tables 2 and 3 are specific to this study. Fuel cycle operations are in equilibrium for those years in which the amount of new fuel loaded in the reactor is fully utilized. For a 30-year operating life with annual refueling, this definition of the equilibrium period covers years 3-28.

FIGURE 1. REPRESENTATIVE NUCLEAR POWER COST, CONSTANT REAL PRICE METHOD AND RATE BASE METHOD (cents per kWh)

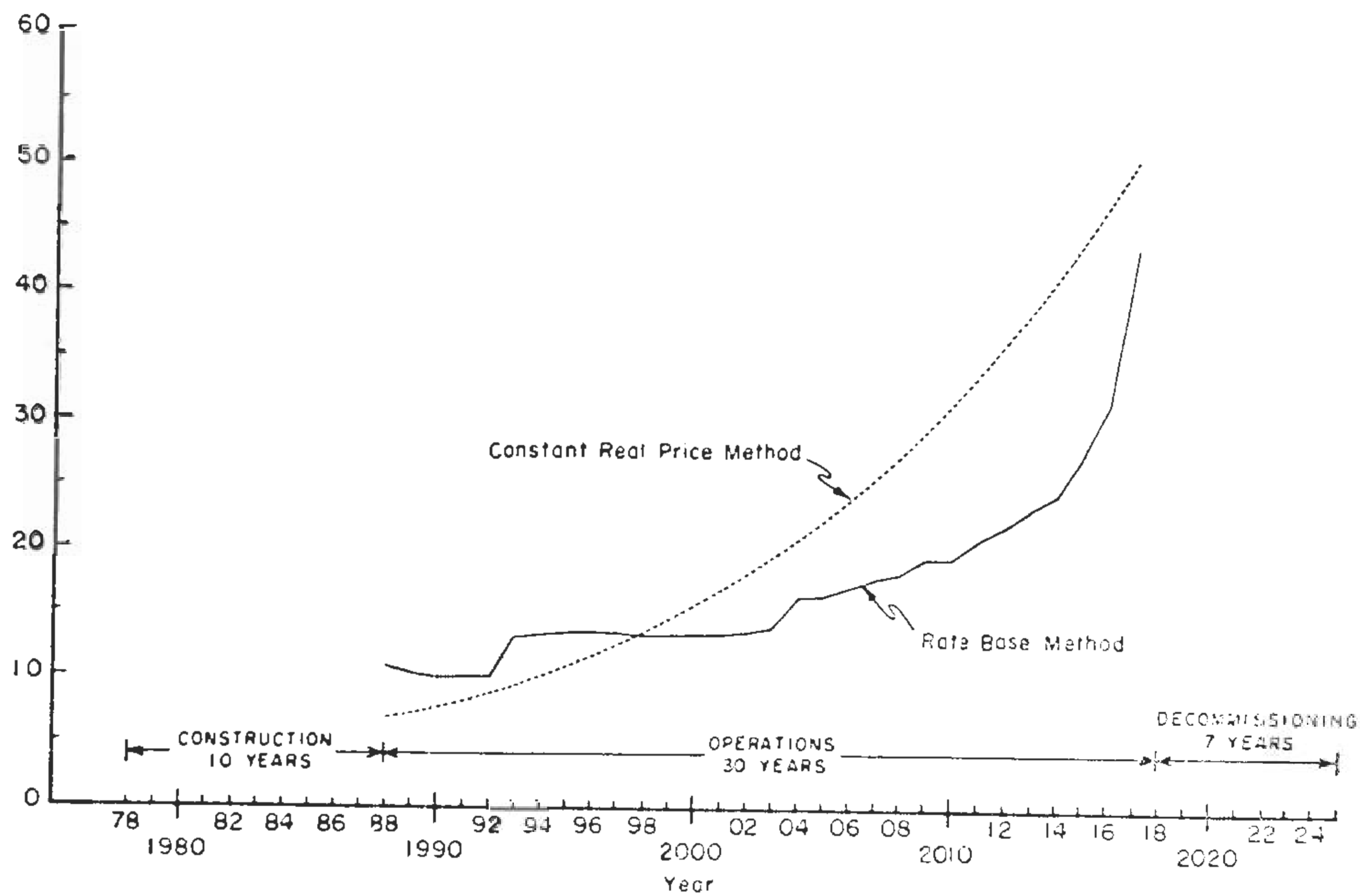
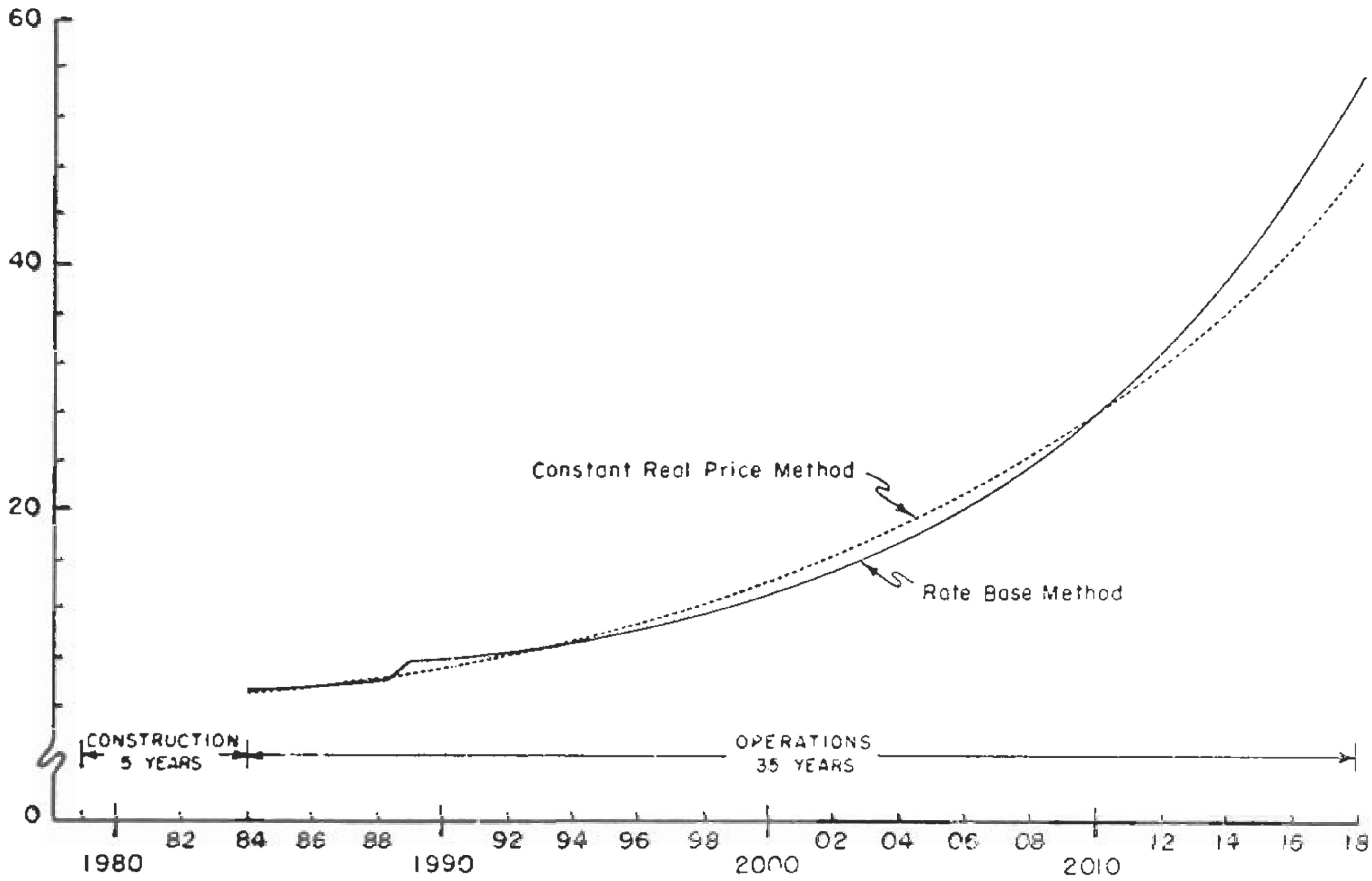


FIGURE 2. REPRESENTATIVE COAL POWER COST, CONSTANT REAL PRICE METHOD AND RATE BASE METHOD (cents per kWh)



declining rate base for much of the operating period for the nuclear plant. In the last few years (e.g., 2010-2017), this pattern changes because fuel cost and actual tax liability grow significantly. The last fuel batch is charged to the last year, and the second-to-last batch is charged to the last two years.

Table 4 summarizes the results of the real cost method applied to both plants. Coal and nuclear power are very similar in estimated real cost in 1988 dollars for the utility. Nuclear cost is 7.3 ¢/kWh, and coal cost is 6.3 ¢/kWh. These values are with present tax provisions. They may be deflated and compared to the Rossin-Rieck 1977 values in Table 1. In 1977 dollars, nuclear power cost would be 3.5 ¢/kWh, which is, surprisingly, identical to the Rossin-Rieck estimate. The coal estimate from Table 4 of 6.3 ¢/kWh (in 1988 dollars) would be 3.0 ¢/kWh in 1977 dollars. This is considerably below Rossin-Rieck's 4.2 ¢/kWh estimate. The major causes for this difference in coal generation may be higher fuel cost and tax liability assumptions for Rossin-Rieck[1/].

However, it is clear that our analysis does not support the conclusion that, for a utility, nuclear power is less costly than coal power in our study of a representative ORBES area.

TABLE 4. CONSTANT REAL COST AND TAX SUBSIDIES FOR REPRESENTATIVE NUCLEAR AND COAL PLANTS (all economic values in 1988 dollars)

	Nuclear Plant	Coal Plant
Conventional after-tax cost to utility, present tax subsidies	7.3 ¢/kWh	6.3 ¢/kWh
Cost to utility with no tax subsidy	11.0 ¢/kWh	7.6 ¢/kWh
Tax subsidy	3.7 ¢/kWh	1.3 ¢/kWh
Average generation for 1,000 MWe of capacity, billion kWh/y	5.435	5.260
Approximate annual tax subsidy for 1,000 MWe capacity	$201 million	$63 million

1/ Rossin-Rieck assumed coal cost at $1.20 per million Btu ($\overline{M}$Btu) in 1977 dollars, or $1.28 in 1978 dollars, 22¢/$\overline{M}$Btu above our Table 2 assumption.

Tax subsidies

As a result of our earlier analysis of tax subsidies and nuclear power in California, we learned that nuclear power receives a major tax subsidy on the order of $200 million per year[1/]. In the ORBES study, we wish to know to what extent comparative costs of coal and nuclear power are influenced by tax subsidies.

To define a corporate income tax structure without tax subsidies, we assume revisions in major provisions affecting deductions and credits. We make these specific assumptions:[2/]

(1) Interest payment deductions are eliminated. This causes the treatment of debt payments to be identical to the treatment of payments to common and preferred stock holders. Both are liable to taxation.

(2) The investment tax credit is eliminated.

(3) Method of depreciation for tax purposes is made identical to depreciation for net income purposes. Normal straight line depreciation is used.

(4) Tax lives are made identical to depreciation periods used in net income calculation. Consequently, nuclear power investment is depreciated over 30 years and coal plant investment is depreciated over 35 years.

(5) AFUDC allowances in the construction period are treated as net income, but are not taxed as earned. Income flowing from AFUDC increments to rate base is taxed as received during the operation period. For AFUDC, then, the subsidy and non-subsidy treatment is uniform.

The SIMCON model is used again to estimate the economics of nuclear and coal power without Federal and Indiana corporate tax subsidies. The results appear in the second row in Table 4. Nuclear cost is now 11.0 ¢/kWh, while coal cost is 7.6 ¢/kWh.

An important conclusion follows. Within our present corporate income tax structure, nuclear power cost is slightly higher than or comparable to coal-generated electricity (e.g., Table 1; Table 4, row 1). However, when tax subsidies are excluded, nuclear power appears to be considerably more expensive (Table 4, row 2). The subsidy received by nuclear power is almost threefold greater than the subsidy received by coal power (Table 4, row 3).

The explanation of the cause of the magnitude of this difference in tax subsidies appears to lie in the difference in capital intensity for the two processes. In 1988 dollars, the representative nuclear plant has a rate base investment of $3,238 per kW at the beginning of operation in 1988. The coal plant has a rate base investment of $1,364 per kW in 1988 dollars at the beginning of its operation in 1984.

It would appear that, at the present time, nuclear power growth in the ORBES region is predicated upon a major differentiation in tax subsidies received by coal and nuclear power, or upon different assumptions with respect to economic parameters, or both.

1/ "Nuclear Economics," pp. 52-53.

2/ Recall that corporate income tax provisions affecting power generation are described in the Appendix.

Timing of Taxation and Income

It was anticipated that the timing of net income, tax liability, and funds flow would create particular incentives for utility planning. Figures 3 and 4 show these accounts for the representative ORBES nuclear and coal plants located in southern Indiana. In this discussion the rate-base pricing algorithm is used in the SIMCON model. This provides a representation of actual regulatory behavior[1/].

In Figure 4, note that net cash earned is less than $20 million annually for the last 11 years of operating the coal plant. During this period, revenue requirements rise from $800 million per year in 2008 to $1.9 billion in 2018. It appears that there is little financial incentive to operate the hypothetical coal plant during the last third of its operating life. The after-tax net income curve is similar, being less than $10 million annually during the 2008-2018 period. In fact, net cash income is negative in 2016-2018, and net income itself is negative in the last year.

However, tax liability is high during these last years, and is declining from $26 million in 2008 to $17 million in 2018.

In contrast, the construction period and the first years of operation show quite a different pattern. Tax liability is negative in the construction period and the first two operating years, and remains below $5 million until 1989.

After-tax profit actually reaches its highest level during the construction period, being above $50 million in 1982 and 1983. Net cash income is negative during the construction period. It is $45 million during the first operating year, and rises to $57 million in the sixth operating year before beginning to decline.

The pattern described here is equally appropriate for nuclear and coal plants. It arises from the interaction of regulatory, tax, and net income accounting. Regulatory policy gives a constant return to capital on a normally depreciating rate base. Consequently, annual return to capital declines in parallel to the normally depreciating rate base.

Tax policy will give the lowest after-tax cost to utilities and their customers if credits, exclusions, and deductions are claimed at the earliest possible dates. As a result, no depreciation deductions will be available in the last years of a plant's life.

Net income and net cash flows follow from the regulatory and tax policies, and are very low or negative in the last years of a plant's life.

The overall result is the creation of a financial incentive for premature construction of new plants and premature retirement of old plants.

1/ It is surprising to see that overall liability is comparable with both pricing methods. The 47-year annual equivalent tax liability for the nuclear plant with the theoretical real cost method is -$8 million per year. The rate-base pricing method has an annual equivalent tax liability of -$5 million.

FIGURE 3. NUCLEAR POWER: AFTER-TAX NET INCOME, TAX LIABILITY, AND CASH FLOW (million dollars)

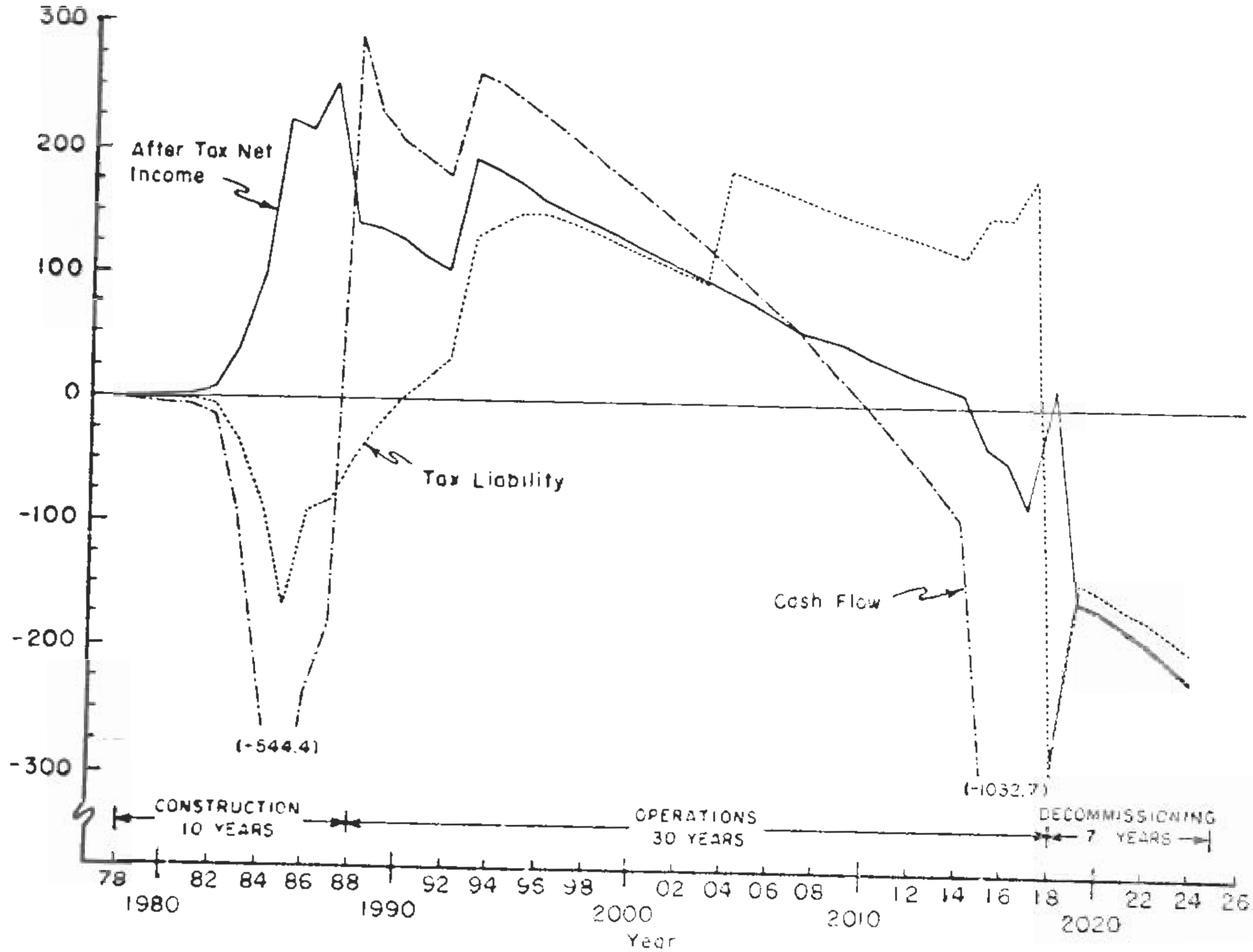
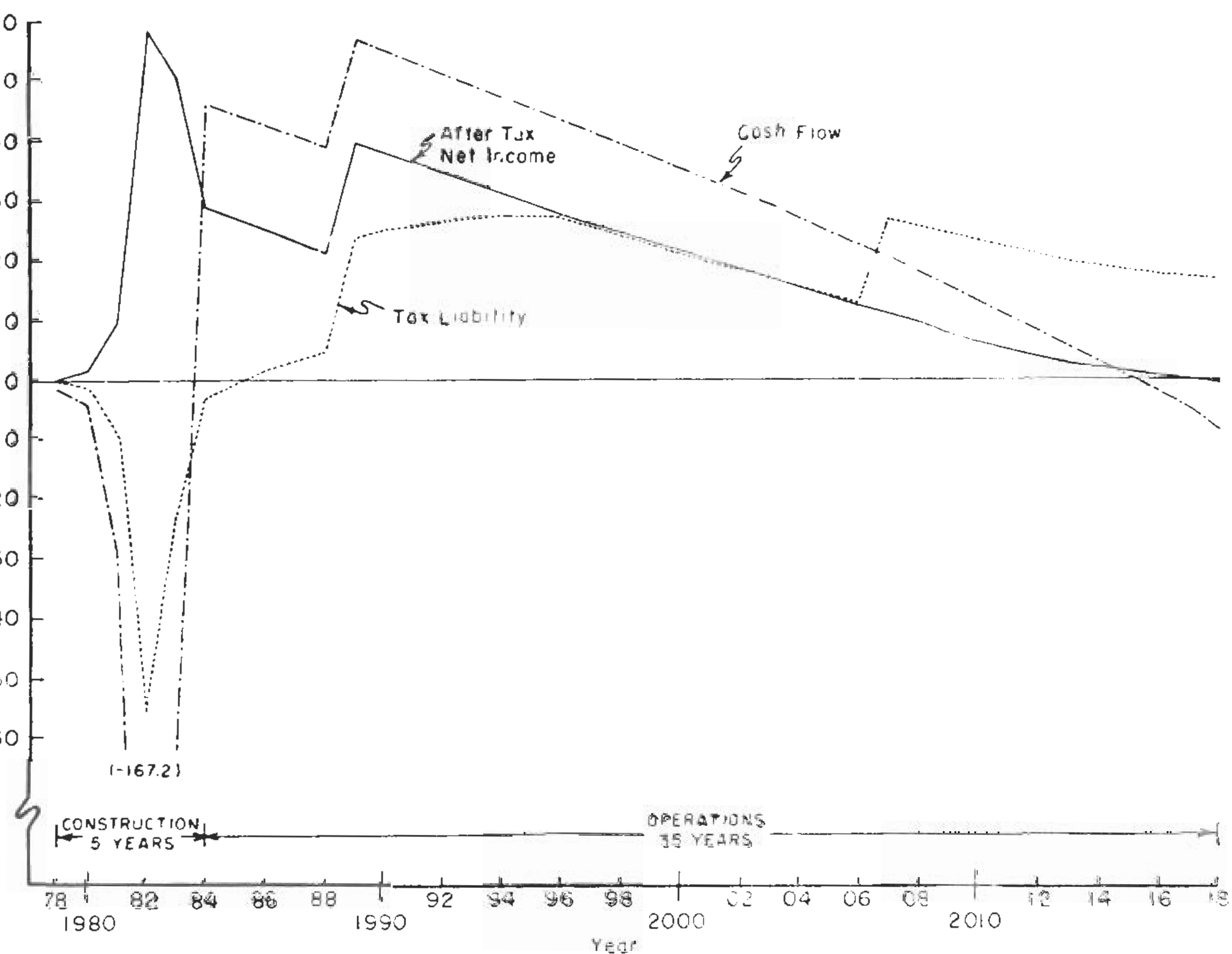


FIGURE 4. COAL POWER: AFTER-TAX NET INCOME, TAX LIABILITY, AND CASH FLOW
(million dollars)



Inflation and Interest

The assumptions with respect to general inflation and interest rates which we used in the preceding discussion are typical of much current work. An overall inflation rate of 7% is typical[1/] and the 9.5% interest rate for utilities was applicable to Public Service of Indiana.

However, the economic situation in late 1979 is quite different from that of the recent past. Prime commercial lending rates have exceeded 14%, and new utility bonds have yielded between 11 1/2% and 12%. At the same time, inflation in the Consumer Price Index has been at annual rates between 8 1/2% and 9 1/2% in the past three quarters.

Although utility bond rates of 12% are historically very high, they define a real interest rate which is currently zero or negative with respect to the Consumer Price Index.

Similarly, home mortgage rates have increased rapidly.

Figure 5 provides perspective on this problem. The era between the Korean and Vietnamese wars (roughly 1952-1965) had a basic price stability. Wage and price controls brought a brief return to price stability (1970-72). However, this price stability ended with the cessation of controls and the energy price increases which began in 1973.

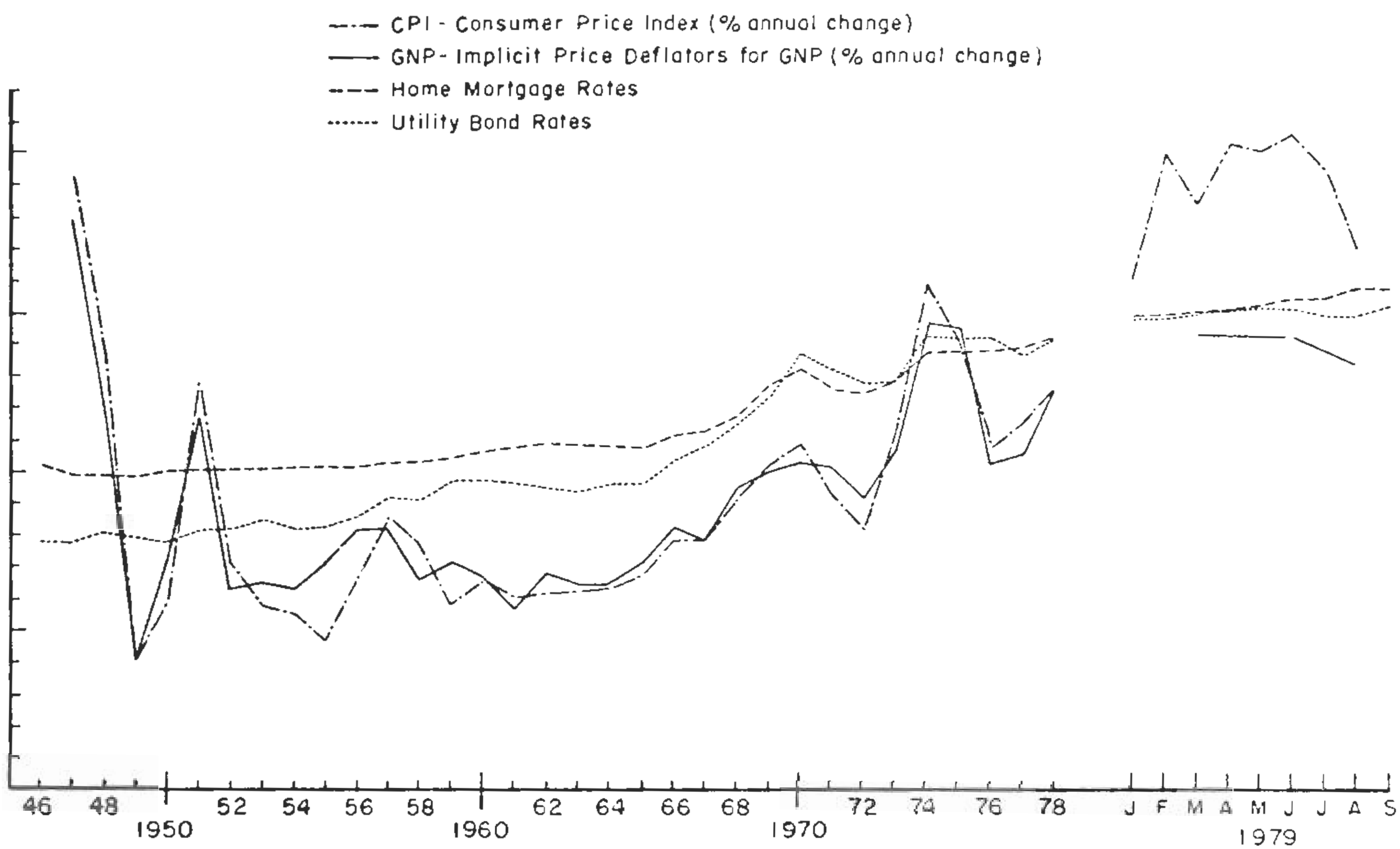
Since, as noted, coal and nuclear power differ in capital intensity, we are concerned about the impact of higher inflation and interest rates on the real cost of generation. To examine this impact, we evaluate the representative coal and nuclear power plants through the SIMCON model. Each interest rate and return to capital is increased by adding 5%. Overall inflation is increased by 5%, from 7% to 12%. Each cost factor experiences an inflation equal to the product of general inflation and real inflation for that factor. (E.g., from Table 3, uranium ore price increases by 13.1% per year, the result of 1.12 * 1.10 = 1.131.) These new assumptions are summarized in Table 5, Part A.

The effect of higher inflation and returns to capital are summarized in Table 5, Part B. After-tax costs for coal and nuclear power each increase by one-half. The margin favoring coal power is in percentage terms essentially unchanged. The overall tax liability remains negative for both the coal and nuclear plants.

The cost to utilities without tax subsidies is again calculated, and is shown in Table 5, Part B, row 2. The tax subsidy for nuclear power more than doubles, from 3.7 ¢/kWh (Table 4) to 7.8 ¢/kWh (Table 5). The coal subsidy rises less, from 1.3 ¢/kWh to 2.0 ¢/kWh.

1/ General inflation assumptions were 7% in Knecht's work (1978); Brandfon (1979) assumed 8% in 1979, 7% for 1980-84, and 6% for 1985 and thereafter.

FIGURE 5. INFLATION AND INTEREST RATES, 1946-79



SOURCE: SURVEY OF CURRENT BUSINESS, AND ECONOMIC REPORT OF THE PRESIDENT

We conclude that, if the high inflation and interest rates of late 1979 become characteristic of the future, then (1) coal power will slightly increase its margin over nuclear power with respect to utility after-tax cost, and (2) the tax subsidy enjoyed by nuclear power will increase.

On this latter point, we note that with low inflation and interest assumptions, the nuclear tax subsidy equals 50% of utility cost (Table 4). With high inflation and interest assumptions (Table 5), the nuclear tax subsidy equals 70% of utility cost.

TABLE 5. HIGH INFLATION, INTEREST, AND RETURN TO CAPITAL

Part A. Basic Financial Assumptions

	Low inflation	High inflation
Overall inflation	7%	12%
Interest rate	9.5%	14.5%
Return to preferred equity	9.5%	14.5%
Return to common equity	14.7%	19.7%
AFUDC rate	9.5%	14.5%

Part B. Impact of High Inflation and Interest Rates, 1988 Prices

	Nuclear plant	Coal plant
Present subsidies, after-tax cost to utility	11.1 ¢/kWh	9.3 ¢/kWh
Cost to utility with no subsidies	18.9 ¢/kWh	11.3 ¢/kWh
Tax subsidy	7.8 ¢/kWh	2.0 ¢/kWh
Average generation for 1,000 MWe capacity, billion kWh/y	5.435	5.260
Approximate annual tax subsidy	$424 million	$105 million

SECTION 3

SPACE AND WATER HEATING COST

The last section analyzed the comparative costs of nuclear and coal power generation.

It examined the impact of corporate and state income tax policy on utility economics, and explored the significance of much higher interest and inflation rates.

This section investigates comparative home heating costs for space and water.

Space heating is causally connected with coal use by means of electric heating. Each Btu of coal-generated electric energy utilized in residential heating will require at least 3.7 Btu of direct coal energy1/. This is inherent in the technology, a consequence of steam generation of electricity and losses in transmission and distribution. If the energy requirement of coal mining and transportation and of utility, mine, and rail system construction could be estimated, total energy per Btu utilized in home heating may approach 5:1.

It is therefore of considerable interest to the ORBES investigation to determine to what extent electric heating will be developed in the region. A typical home utilizing electric heating may require 30,600 kWh of electricity for this purpose2/. In the area studied, growth in electric heating exceeds growth in the total number of customers3/. The current residential average use is 10,500 kWh per customer, 20% above the 1973 average. If electric heating continues to grow, it will create considerable new demand for electricity, and for coal or nuclear energy to generate that electricity.

Assumptions

Our analysis of comparative costs is based in part on the assumptions in Tables 6 and 7. Purchase cost in Table 6 is the estimated variation in new

1/ Assume 33% efficiency in generation, 10% transmission loss to home, and 10% energy loss in the home.
2/ Assuming 94 MBtu annual heating requirement. See Table 7.
3/ PSI Annual Report, op. cit.

home cost associated with the choice of heating system. It is immediately apparent that a builder installing electric resistance heating has the lowest installation cost.

Actual performance indicates the expected lifetime efficiency in providing heat energy. For the oil, gas, electric resistance, and wood systems, the performance ratio is, simply, the ratio of heat energy delivered into the home to energy contained within the fuel. A .5 performance ratio for wood means 2 Btu of energy in the wood are required for each Btu of heat energy in the home.

For the heat pump, the performance ratio gives the amount of heat energy transferred into the home for each Btu of electrical energy used by the heat pump. For example, utilizing 3,412.8 Btu (one kWh) in the heat pump transfers 6,143 Btu of energy from the outside into home heat.

Performance for a solar system means the proportion of annual heat energy (or water heat energy) which the system can supply. We assume a solar system can supply 60% of the needed space heat, and that a solar hot water system can supply 70% of the energy required for water heating.

Major differences exist in end-use efficiencies for oil, gas, resistance, and wood heat. Wood burning is least efficient in deriving energy, converting only 50% of the energy in wood into space heat energy.

All energy prices are given in customary units and in dollars per million Btu ($/MBtu). A price of $100 per cord of wood assumes a cut and delivered price, making its price similar in definition to that of other energy forms. Note that electricity price is highest on a Btu basis. Natural gas is lowest, followed by wood.

The last row of Table 6, Part A, expresses energy conversion factors. For example, one gallon of fuel oil has .141 million Btu.

Part B in the Table shows additional assumptions for water heating. Again, purchase cost is lowest for a conventional electric hot water heater, and highest for a solar unit.

Performance efficiencies in hot water units are assumed to be identical to those in space heating, except for the solar system.

A solar hot water system operates 12 months a year, and is operating during the summer period of maximum solar insolation. We assume the solar hot water system delivers 70% of the annual energy requirement. This might be visualized as 95% delivery in the summer, 45% in the winter, and 70% in the spring and fall.

Solar back-up systems are full scale for both space and water heating.

No attempt is made to evaluate the alternatives with respect to convenience or impact upon associated activities. As examples of points not considered with respect to wood burning: (1) consequences of system failure in

TABLE 6. HEATING SYSTEM ASSUMPTIONS

Part A. Space Heating

Fuel type	Fuel oil	Natural gas	Electric systems: Resistance	Electric systems: Heat pump	Solar	Wood
Purchase cost	$2200	$2500	$1800	$5500	$8200	$3000
Performance	.7	.8	.9	1.8	.6	.5
Unit price (1979 $)	89.9 ¢/gal	$1.698/MCF	3.91 ¢.kWh		---	$100/cord
Energy price (1979 $/MBtu)	$6.376	$1.672	$11.46		---	$4.44
MBtu/unit	0.141	1.016	.0031428		---	22.52

Part B. Water Heating

	Fuel oil	Natural gas	Electric resistance	Solar
Purchase cost	$485	$350	$250	$2800
Performance	.7	.8	.9	.7

winter on plumbing or family members, (2) probability of accidents, (3) wood availability.

Another example of excluded considerations arises with respect to electric heat pumps. Heat pumps are least efficient when they are most needed. In very cold weather, when space heat energy is in greatest demand, the heat pump is at its minimum efficiency in extracting heat from the outside environment. Consequently, peak demand (measured in kW) increases more rapidly than energy demand (measured in kWh) in cold weather. As with the wood system, no attempt is made to consider (1) system failure, here including the utility, (2) probability of accidents for either coal or nuclear power, and (3) availability.

The comparison, then, is solely economic, and examines customer costs and tax subsidies.

Other assumptions which are generally applicable to all systems appear in Table 7. We are considering a representative 1500 square foot house in southern Indiana. It requires 94 MBtu space heating energy and 21.5 MBtu water heating energy1/.

These are not conservative values. We would not be surprised to find future new homes with one-half these energy requirements. Such homes would make extensive use of energy conservation practices and passive solar heating. However, these values of 94 MBtu space heating and 21.5 MBtu water heating are representative of current planning.

The family income is assumed to be $25,000 and the marginal tax rates are .28 for the Federal personal income tax and .02 for the Indiana personal income tax. The solar system qualifies for the Federal solar tax credit which is 30% of the first $2000 and 20% of the next $8000 of purchase cost.

The property tax rate is 12.8397% on assessed valuation, and assessed value is about 26.5% of market value. Consequently, the property tax rate is assumed to be 3.4% on original cost. The solar system is exempt.

The Indiana State sales tax rate is 4% on fuel purchases.

Maintenance expense is assumed to be 2% of purchase cost for each system. However, for the back-up source in the solar system, maintenance expense is 1% of purchase cost2/.

1/ With 5699 degree days in southern Indiana, 1500 square feet, and an average energy requirement of 11 Btu per degree day per square foot, the result is 94 MBtu per year. The hot water requirement of 21.5 MBtu is equivalent to the original energy requirement to heat 86 gallons per day from 44°F to 130°F. This latter calculation excludes energy for temperature maintenance. See William D. Schultze et al., "The Economics of Solar Home Heating," Print, Joint Economic Committee, U.S. Congress, 95th Cong., 1st Sess., March 13, 1977; and U.S. Energy Research and Development Administration, "An Analysis of Solar Water and Space Heating," November, 1976.
2/ Recall that, compared to a normal system, a back-up system will be used 40% as much for space heating, and 30% as much for water heating.

TABLE 7. GENERAL ASSUMPTIONS FOR SPACE AND WATER HEATING SYSTEMS

Life of systems	20 years
Discount/interest rate	9.5% or 14.5%
Amortization factor	.1135 or .1554
Annual maintenance expense, % of purchase cost	2%
Property tax rate, conventional and wood	.034
Property tax rate, solar	0
Assumed income level	$25,000
State personal income tax marginal rate	.02
Federal personal income tax marginal rate	.28
Sales tax rate on fuel and wood	4%
General inflation rate	7% or 12%
Heating degree days	5699
Annual space heating requirement	94 MBtu
Annual water heating requirement	21.5 MBtu
Real inflation, oil and electricity	0% or 3.5%
Real inflation, natural gas price	0%, 3.5%, or oil price parity, 5 yrs.
Real inflation, wood price	0%, 1.75%, or 3.5%

As suggested by the discussion in the previous section, interest rates of 9.5% and 14.5% are examined.

All systems are assumed to have a 20-year life without salvage value.

General inflation is, as in the preceding section, assumed to take place at rates of either 7% or 12%. General inflation affects maintenance expense, fuel cost, and sales tax on fuel.

Real inflation in oil and electricity energy prices is examined in two dimensions. First, real inflation is assumed in some cases studied to be zero -- energy prices grow at rates exactly equal to general inflation. Second, real inflation is assumed in other cases to lead to a doubling in real energy prices in 20 years. This doubling requires a real inflation rate of 3.5% annually1/

Real inflation in natural gas price includes the assumptions for oil and electricity: cases with 0% or 3.5% real inflation interacting with general inflation. However, natural gas also is examined with a third price assumption. Whatever the oil price on a Btu basis, natural gas is assumed to reach the same Btu price in 5 years, and from that point on oil and natural gas have the same Btu price and grow at the same rate.

Real inflation in wood prices has three alternative assumptions: zero, one-half the 3.5% rate, and 3.5%. The 1.75% rate might apply if improved forestry management and lower costs in wood fuel preparation caused wood fuel price to rise less rapidly than oil, natural gas, or electricity prices.

It should be understood that even the lowest inflation assumption raises nominal prices considerably. A 7% general inflation raises oil prices from 89.9¢/gallon to \$3.48/gallon in 20 years. A high general inflation (12%) linked with a real inflation of 3.5% raises the oil price to \$17.20.

In the discussion which follows, we shall attempt to determine what consistent patterns may be observed amidst these widely varying assumptions.

Annual Equivalent Cost

Given the assumptions described above, there are 108 possible cases based upon varying assumptions in interest rate, general inflation, and real energy price inflation rates. Several can be dismissed as illogical. First, we note that an overall inflation rate exceeding the interest rate defines a 20-year period in which credit institutions lend at negative real interest. We exclude the cases with 14% inflation and 9.5% interest. Second, the closely parallel paths of inflation and interest, and the general difference of 3%-5% indicate that a 7.5% difference has not existed previously and is unlikely to in the future. We exclude the cases with 14.5% interest and

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1/ Recall from the previous section that a real inflation rate interacts with an overall rate: 1.035*1.12 = 1.159 means a nominal inflation of 15.9% in fuel. Then, (1.159)**20 ≅ 2*(1.12)**20.

general inflation of 0% and 7%. Finally, we suppose that inflation in real energy prices is a major factor in overall inflation. Consequently, the only cases reported for the 14.5% interest rate have overall inflation at 12% and real energy price inflation.

As a result of this logic, we focus upon 6 cases.

The structure of the analysis is indicated by Table 8. In that Table, all amounts are expressed in constant 1979 dollars with 1979 prices. The low interest assumption of 9.5% is used.

The annual equivalent value[1/] of each term discussed previously is reported in Table 8.

The natural gas system has the least cost to the customer over the 20 years. Its annual equivalent cost is $474 per year, considerably lower than the solar/gas system ($1048) or the wood system ($1192)[2/].

Since electric resistance had the lowest purchase cost, it has the lowest mortgage payment ($204). However, it is the most expensive system for the customer to use.

With these assumptions, non-availability of natural gas would result in wood fuel being the least costly (at $1192) followed by the heat pump (at $1215) and oil ($1235).

The greatest total subsidy ($802) is received by the solar/gas system. The largest component of this subsidy is the exclusion of property tax liability which would be $280[3/] per year. The Federal solar income tax credit has an annual equivalent value of $191, and interest deductions on mortgage payments for State and Federal income taxes constitute the remainder of the solar/gas subsidy.

1/ The precise formulation is $AEC_j = a(i)*PV_j(i)$. Annual equivalent cost for item j is AEC_j. The amortization factor for interest rate i is a(i), and is defined by a(i) = i(1+i)**20/(((1+i)**20)-1). The present value of item j is $PV_j = C_{jt}/(1+r)$**t over 20 years, t = 1, 20. C_{jt} is cost or credit item j as actually occurring in year t. Total customer cost is the sum of the annual equivalent cost of each of the first eight items in Table 8.

2/ In the preceding section on utility generation costs, dollar values are expressed in annual equivalent costs over the operating periods of the plants. In this section, the residential systems were assumed operable in 1979, and annual equivalent costs cover the period 1979-1999. The two can be compared by deflating the 1988 dollars to 1979 dollars. For the 7% inflation assumption, the deflation factor would be 1.838. For the 12% inflation assumption, the deflation factor would be 2.773. For example, the 7.3 ¢/kWh figure from Table 4 could be expressed as 4.0 ¢/kWh in 1979 dollars. I.e., 4.0 ¢/kWh = 7.3 ¢/kWh ÷ 1.838.

3/ The annual property tax on the solar system would otherwise be $8200*.0342, equal to $280.

TABLE 8. COMPARATIVE COSTS AND TAX SUBSIDIES: CONSTANT 1979 DOLLARS, 9.5% INTEREST, NO REAL ENERGY PRICE INFLATION (rounded to nearest dollar). CASE #1

	Single Systems					Solar Gas & Electric Systems					
	Oil	Natural gas	Electric resistance	Heat pump	Wood	Solar	Gas backup	Total	Solar	Electric backup	Total
Mortgage payment	363	284	204	624	340	931	284	1215	931	204	1135
Maintenance	64	50	36	110	60	164	25	189	164	18	182
Fuel cost	856	196	1197	598	835	0	78	78	0	479	479
State income tax savings	-13	-10	-7	-22	-12	-12	-10	-22	-12	-7	-19
Federal income tax savings	-179	-140	-101	-307	-168	-169	-140	-309	-169	-101	-270
Federal solar tax credit	0	0	0	0	0	-191	0	-191	-191	0	-191
Property tax	109	86	62	188	103	0	86	86	0	62	62
Sales tax: fuel	34	8	48	24	34	0	3	3	0	19	19
Total customer cost	1235	474	1439	1215	1192	722	326	1048	722	674	1396
Rank	5	1	7	4	3			2			6
Subsidy	192	150	108	329	180	652	150	802	652	108	760
Total without subsidies	1472	624	1547	1545	1372	1374	476	1850	1374	782	2156
Rank	3	1	4	4	2			6			7

TABLE 9. COMPARATIVE COSTS OF SPACE HEATING ($/year)
(rounded to nearest $5; the two least-costly solar systems are shown in each case)

1979 dollars, 9.5% interest, no real fuel inflation — case #1

gas	$ 475
solar/gas	1050
wood	1190
heat pump	1215
oil	1235
solar/elec.	1395
electric	1440

1979 dollars, 9.5% interest, real fuel inflation — case #2

gas	$ 530
solar/gas	1070
inexp. wood	1301
heat pump	1385
exp. wood	1430
oil	1485
solar/elec.	1535
electric	1785

1979 dollars, 9.5% interest, no real fuel inflation — case #3

gas	$ 645
solar/gas	1240
heat pump	1710
solar/wood	1730
wood	1820
oil	1885
electric	2305

Low inflation (7%), 9.5% interest, real fuel inflation — case #4

gas	$ 775
solar/gas	1285
solar/inexp. wood	1830
inexp. wood	2070
heat pump	2105
exp. wood	2370
oil	2445
electric	3095

High inflation (12%), 14.5% interest, real fuel inflation — case #5

gas	$1020
solar/gas	1670
solar/inexp. wood	2390
inexp. wood	2730
heat pump	2775
exp. wood	3130
oil	3240
electric	4095

Oil/gas parity, high inflation (12%), 14.5% interest, maximum real inflation in oil, electricity, and wood prices — case #6

solar/gas	$2390
solar/exp. wood	2510
gas	2570
heat pump	2775
solar/electric	2850
exp. wood	3130
oil	3240
electric	4095

Table 9 reports summary results for all 6 cases. Solar costs were calculated for every solar/backup system combination for each case. For Table 9, the two least-costly solar combinations are generally shown for each case. Each case in Table 9 is based upon a detailed analysis of the form shown in Table 8 for the first case.

Given the uncertainty surrounding future inflation, interest, and energy prices, it is somewhat unexpected to see three important conclusions emerge from Table 9. First, electric resistance heating is the most expensive for the customer in every case.

Second, natural gas heating is usually the least expensive. Solar/gas is usually second, and always second or first.

Third, if natural gas is unavailable, a wood system, or a solar/wood system, is the least expensive in five of the six cases.

Case 5 shows the results of high inflation and interest rates in association with exponential growth in real oil, gas, wood, and electricity prices. All systems show major increases, but the ranking is unchanged from Case 4. Again, gas is least costly and electric resistance heating most costly. Solar/gas is second, and a heat pump less costly than expensive wood, oil, or electric resistance heating.

In Case 6, natural gas price accelerates to reach equity (on a Btu basis) with the increasing oil price in 5 years. Both continue to grow exponentially. This case shows the most expensive wood fuel price and the solar/electric system cost. The result is the only case in which a solar system is least costly. In addition, the solar/electric system is less costly than expensive wood, oil, or conventional electric resistance heating.

Tax Subsidies: Corporate and Personal

The magnitude of the combined effects of corporate and personal tax subsidies can only be approximated. Table 10 does so for the case with constant 1979 dollars, current energy prices, and 9.5% interest. The personal tax subsidies are taken from Table 8.

The corporate income tax subsidies are derived from Table 4. The 3.7 ¢/kWh and 1.3 ¢/kWh subsidies for nuclear and coal power are deflated from 1988 dollars to 1979 dollars by 7% per year, and the results (2.0 ¢/kWh and 0.7 ¢/kWh) are multiplied by the electric heat requirement of 30,600 kWh per year. The solar/electric system is assumed to use coal-generated electricity, hence the utility segment subsidy in the solar/electric system is 40% of the electric heating amount.

According to these figures, the annual value of the subsidy received by the solar/electric system is the largest. At $846, it is 61% of customer cost. The single electric system using nuclear power has a $720 annual subsidy, 85% of which is received by the utility in the form of the corporate income tax subsidy.

TABLE 10. ILLUSTRATION: TOTAL TAX SUBSIDIES FOR HOME HEATING
($/year; Case #1)

Type of System:	Solar/Electric solar	Solar/Electric electric backup	Solar/Electric total	Wood	Electric (coal)	Electric (nuclear)
Type of Subsidy						
Personal income and property tax						
Property tax exclusion	$280	$ 0	$280	$ 0	$ 0	$ 0
State income tax deds.	12	7	19	12	7	7
Federal inc. tax deds.	169	101	270	168	101	101
Federal tax credit	191	0	191	0	0	0
Total	652	108	760	180	108	108
Corporate income tax, utility generation	0	86	86	0	214	612
Total subsidies in illustration	652	194	846	180	322	720
Cost to customer	722	674	1396	1192	1439	1439
Total economic cost: subsidies plus customer cost	1374	868	2242	1372	1761	2159

If each subsidy listed in Table 10 were eliminated, the least costly system would be wood, then electric (coal generation), followed by electric (nuclear generation), and the solar/electric system would rank last.

However, these figures should be interpreted cautiously. Basic weaknesses are apparent in this approach. For example, the property tax subsidy for the solar component is based upon the exemption from a 3.42% annual property tax. This amount ($280) would, in the absence of the exclusion, be due each year. But in the utility analysis, property tax liability is assumed to begin at 1% of cumulative expenditures and decline on a straight line basis. And AFUDC earnings are excluded from the property tax basis, although viewed as income earning investment by the regulatory commission.

This can be summarized as follows: each $100 invested in a non-solar home heating system has a $3.42 annual property tax liability each year for 20 years. Each $100 of rate base investment in a nuclear plant has a $0.008 property tax liability in the first year, and this declines to $0.005 in the tenth year, $0.003 in the twentieth year, and $0.0003 in the last year.

Clearly, Table 10 might be amended to define a property tax subsidy for the electric utility. However, we assume for the present that differential property tax liability is normal, and so attribute a $280 annual subsidy to the solar system exclusion from property tax liability.

Besides this problem of property tax definition, we have no basis for calculating tax subsidies received by solar equipment manufacturers, wood stove fabricators, power plant contractors and fabricators, or by the industries which supply these manufacturers.

Table 10 has limited value for comparing corporate/personal tax liabilities between systems. However, it does show that the corporate tax subsidies are a significant factor in reducing the customer's cost of electric space heating and that nuclear power is particularly affected.

Water Heating

Table 11 summarizes the results of the water heating cost analysis. They are similar to the space heating analysis. Natural gas appears to be the least costly method, and electric water heating is always the most costly. The analysis in which natural gas price reaches Btu parity with oil price also does not disturb this ranking. For natural gas/oil price parity, gas cost is $545 rather than $200 in Case 5, and solar/gas cost is $560 rather than $440.

As with space heating, the system with lowest initial cost -- electric -- has the highest annual customer cost[1/].

Solar/gas and solar/electric are less costly than solar/oil in the first three cases, but solar/oil is less costly than solar/electric in the last two cases.

1/ See Table 6 for initial purchase cost of each system.

Whenever inflation occurs (the last four cases), a solar/electric system is always less costly than a conventional electric hot water system.

Finally, the impact of higher interest and inflation is evident from comparing the last two cases in Table 11. While all systems are more costly, the ordering is almost unchanged, and each conclusion directly above remains unaltered.

TABLE 11. COMPARATIVE COSTS OF WATER HEATING ($/year)
(rounded to nearest $5)

1979 dollars 9.5% interest no real fuel inflation case #1		1979 dollars 9.5% interest real fuel inflation case #2		Low inflation (7%) 9.5% interest no real fuel inflation case #3	
gas	$ 85	gas	$ 100	gas	$ 120
oil	256	solar/gas	285	solar/gas	330
solar/gas	285	oil	315	oil	400
electric	310	solar/elec.	365	solar/elec.	440
solar/elec.	340	electric	390	electric	505

Low inflation (7%) 9.5% interest real fuel inflation case #4		High inflation (12%) 14.5% interest real fuel inflation case #5	
gas	$ 150	gas	$ 200
solar/gas	340	solar/gas	440
solar/oil	460	solar/oil	605
solar/elec.	495	solar/elec.	645
oil	530	oil	700
electric	690	electric	910

SECTION 4

CONCLUSIONS

Our analysis has focused upon several economic factors which will influence future energy production and use in the ORBES region. Although industry analysts generally conclude that nuclear power is less costly to the utility, our finding is that coal power is somewhat less costly. If interest and inflation rates should increase, we find that the coal advantage increases.

Tax subsidies are a major consideration in utility economics. For prospective coal and nuclear plants in the representative ORBES area studied, the annual equivalent tax liability is negative. The greater capital intensity of nuclear power results in its tax subsidy reaching 3.7 ¢/kWh in future 1988 dollars, almost three times the coal subsidy.

Higher interest and inflation rates increase tax subsidies. The nuclear subsidy equals 70% of the utility cost, and the coal subsidy is estimated to be 22% of utility cost.

The timing of tax liability and revenue is such that little after-tax net income is received by the utility in the last years of a plant's operations. Tax liability is high. The pattern is reversed in the construction period and first years of operations: after-tax net income is high and current tax liability is negative.

Consequently, the tax and regulatory systems interact to create incentives for premature construction of new plants and premature retirement of existing plants. The timing pattern seems equally applicable to coal and nuclear power.

This discussion of comparative costs does not attempt to examine known or possible environmental costs associated with coal or nuclear power. We make no attempt here to investigate nuclear fuel disposal in the ORBES region, decommissioning, or reactor safety. Similarly, we do not study coal mine health and safety, strip mine regulation, air pollution damage, or the climatological impact of accelerated coal use.

Our study is limited to comparative costs and tax incidence. Within this boundary, we conclude that coal power is less costly than nuclear power in the ORBES region, and that the tax subsidy received by coal power is significant but considerably less than the subsidy enjoyed by nuclear power.

In the absence of this tax subsidy, it is apparent that no utility would prefer nuclear to coal generation for economic reasons. One author of this report has estimated elsewhere that, if major problems arise with respect to waste fuel disposal, reactor decommissioning, safety requirements, and uranium availability, there is a very small possibility that nuclear power cost may be as high as 22 ¢/kWh[1/]

Volatility in energy prices creates considerable uncertainty with respect to future space and water heating costs. Our examination of costs of providing heat and hot water to an owner-occupied home considered a diverse set of inflation and interest rate assumptions. We found that, for a new home first occupied in 1979, natural gas is the least costly source of space and water heating. Electric resistance heating is the most costly system for the customer on an annual basis, and this is true for both space and water heating.

Although natural gas appears to be the least costly system at present, there is little doubt that natural gas availability will decline. The U.S. Energy Information Administration forecasts that domestic gas production will continue to decline from its 1973 maximum of 22 quadrillion Btu. Including every source of new production, total production may be as low as 15 quadrillion Btu by 1995[2/]

If natural gas prices reach parity with oil prices on a Btu basis in 5 years, and if both continue to accelerate in an economic environment of high inflation and interest rates, a solar/gas space heating system is less costly than a separate gas system. It may be desirable to consider making future natural gas use by homeowners contingent upon installation of solar or wood burning space and water heating.

Comparing corporate and personal income tax subsidies for four sources of home heating, we find the subsidies accruing to a solar/electric system to exceed those received by an electrically heated home using nuclear power generation. For the solar/electric system, the largest subsidies are the Indiana property tax exemption, and the Federal personal income interest deductions and solar tax credit. The nuclear power-electric home heating system has its primary tax subsidy through the Federal and Indiana corporate income tax. Tax subsidies going to electric heating by coal power are less, and for wood burning are minimal.

It was a modest surprise to find that, in the two cases with general inflation and with real energy price inflation in excess of general inflation, solar, wood, and heat pump systems have less annual cost than conventional oil or electric systems. This is true for low general inflation and interest rates as well as high inflation and interest. It is applicable to both space and water heating.

1/ Chapman, "Nuclear Economics," op. cit., Table 18, Section 6.
2/ U.S. Energy Information Administration, Forecasts, Annual Report to Congress 1978, Vol. 3, Ch. 10.

The problem, of course, is that oil or electric space or water heat cost less for a contractor to install, but solar, wood, or heat pump systems have less total cost to the customer.

Our conclusions should be qualified by emphasizing three important limitations. First, our focus is on energy production and use. We have not studied conservation technologies and policies and their effects upon utilities, customers, and the national economy. It may be the case that energy conservation is at present a better general economic policy than energy production. If so, it may have unexpected consequences upon many subjects considered here. We may speculate that efficient energy conservation policies would render less desirable the more costly technologies studied here. In particular, we would expect nuclear power generation and electric space and water heating to be displaced.

A second qualification: our specific analysis applies only to a part of the ORBES region. We chose southern Indiana as the locus of study for one major reason. It is a location where nuclear power and coal generation are economically competitive. In addition, all of the conventional residential fuels are available, and the renewable energy resources (wood heating and solar hot water heating) are economically competitive with conventional fuels. However, our conclusions may not be applicable to other areas in the ORBES region. Variations in coal cost and state corporate income tax policy may alter the coal/nuclear comparison. Similarly, price and availability for natural gas, wood fuel, and solar hot water systems may vary.

Finally, we do not examine the distributional or equity aspects of the cost and taxation questions. Do upper income families benefit disproportionately from the residential tax subsidies accruing to solar hot water heating? How are utility tax benefits distributed among customers, management, and shareholders? What is the regional and national incidence of the Federal corporate and personal income tax subsidies? We have no opinion or information on this question of equity, but realize it is of considerable interest.

It is our overall opinion that these three qualifications (i.e., omission of conservation economics, narrow geographic focus, and absence of distributional information) clearly limit the broad applicability of our findings. However, we believe that further research into these three relevant and important areas would not alter our conclusions, but would instead broaden the context in which they would be interpreted.

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APPENDIX[1/]

CORPORATE INCOME TAX PROVISIONS AFFECTING POWER GENERATION

AFUDC income

The allowance for funds used during construction (AFUDC) has two components. One is an equity component which is added to operating income in arriving at total income. The other, the debt component, reduces actual interest expense in arriving at net interest charges. Net income, while being the difference between total income and interest charges, always includes AFUDC as a positive amount.

The significance of AFUDC, of course, arises from its inclusion in accumulated rate base which is the basis for future rates.

AFUDC when earned is wholly excluded from Federal income taxation. However, the Internal Revenue Service (IRS) does treat income derived from AFUDC rate base as normal income. The rationale is that AFUDC is an accounting entry rather than an actual income item, so no tax liability should be imposed.

By way of illustration, a nuclear plant with construction cost of $2.5 billion might have an 8% AFUDC rate applied to actual plant expenditures and to nuclear fuel inventory acquisition. For a representative $2.5 billion plant having a 10-year construction period from 1978 to 1987, AFUDC would add $600 million to the plant rate base and $40 million to the fuel rate base. None of this is taxed as earned, and all is defined as part of net income.

interest deductions

Interest expense payments are generally viewed in the United States as ordinary business expenses and thereby deductible from taxable income. However, the other form of capital contribution -- stock and equity -- have payments made to them subject to tax liability. Consequently, utilities prefer debt to new stock issues in part because a dollar of new debt reduces overall tax liability while a dollar of new equity does not.

1/ This material is based upon "Nuclear Economics," Section 4, and is taken from "Federal Income Tax Provisions Affecting Nuclear Power," prepared for the October 5, 1979, ORBES meeting in Lexington, Ky.

Value-added taxation of corporate revenue is widely used in Europe. In this form of taxation, taxable value equals revenue less cost of goods, wages, and salaries. Therefore interest, as well as dividends, is subject to this form of corporate income tax.

During the period of plant operations, bond payments to amortize debt may have more than 90% of the payment going to interest in the early years.

investment tax credit

The investment tax credit is a direct reduction in tax liability. At the maximum rate, it is equal to 11 1/2% of qualified investment. Qualified investment is essentially construction cost excluding land and structures. AFUDC is not included Qualified investment is thus approximately 95% of construction cost. The maximum effective rate, then, is 10% of actual construction cost.

This is a significant tax subsidy, its value for a hypothetical new plant being about $725 million. With flow-through accounting and amortization of the credit in five years, customer costs are reduced by nearly $100 million for five years.

A major problem arises from the last 1 1/2% of the investment tax credit and its use as compensation for utility employees; this is discussed below, under "conflict of interest".

accelerated depreciation

For net income determination as well as rate-making, depreciation expense is defined by the normal straight-line basis. Depreciation expense is simply assumed to be spread equally over each year of the plant's life, and is each year equal to 3 1/3% of original cost.

Accelerated depreciation literally speeds up depreciation for tax purposes. By placing larger deductions in earlier years, it shelters significant income in those years from tax liability. The double declining balance method is most effective in terms of maximum tax reduction.

The normal rate is doubled, from 3.33% to 6.67%. This percent is applied to the undepreciated basis at the beginning of each year, and the result is current depreciation for tax purposes.

tax life

The arbitrary tax lives assigned to nuclear power equipment provide an additional tax subsidy. The IRS permits depreciation to be based upon a 16-year period rather than the 30-year expected life. Consequently, the double declining balance method, applied to a 16-year tax life, gives a 12.5% depreciation expense rate. After eight of the 16 years the utility switches over to normal straight line depreciation for the remaining basis. This ensures total depreciation in 16 years.

Similar arbitrarily short Federal tax lives apply to other utility property: 22.5 years for fossil fuel generating systems and 24 years for transmission and distribution equipment[1].

For a $2.5 billion plant, Federal depreciation deduction is $314 million in the first year. Normal depreciation for rate base investment is $104 million. The plant is wholly depreciated for Federal tax purposes by 2003, and no further depreciation expense deductions can be applied to taxable income for the Federal corporate income tax.

repair allowance

The IRS repair allowance has been interpreted to allow a company to elect the larger of either actual repair expenses or the IRS percentage allowance as deductible expense[2]. Utilities frequently select the percentage allowance because it exceeds actual expense.

The repair allowance rate for a nuclear power plant is 3%, giving an allowance of $75 million in 1983 for a hypothetical plant.

non-taxable dividends

As effective tax management brings the utility into a position with no significant tax liability, the utility may exempt its dividend payments from income tax liability for the recipients of the dividends.

Suppose a company normally has a positive and significant net income and net cash receipts: it is in a position to make dividend payments if it elects to do so. Suppose it has, for tax purposes only, no taxable profits. Then, all its dividends would be tax-exempt for dividend recipients: it is essentially a fictional capital repayment.

If dividend payments total $X million, and taxable profit is a smaller $Y million, then Y/X% of each dividend is taxable for recipients.

In determining non-taxable dividends, taxable income is recalculated as "earnings and profits". Essentially, depreciation is recomputed on a straight line basis with arbitrary tax lives.

For the dividend recipient, these tax-exempt dividends remain exempt until they sum to the original purchase price of the stock. At that point, additional tax-exempt dividends become liable to capital gains tax.

1/ See U.S. Internal Revenue Service, "Tax Information on Depreciation," Publication 534, 1979, p. 35.
2/ See Michael Galvin, "Report on Reasonableness of the Income Tax Allowance for Pacific Gas and Electric Company," California Public Utilities Commission, February 11, 1977, pp. 2-4.

It can be noted that this provision increases the value of tax subsidies pertaining to new construction by creating deductions which can be passed along to shareholders. One New York utility reported 85% of its dividend payments were tax exempt in 1977.

conflict of interest

Under present Federal tax law, the last 1 1/2% of the 11 1/2% in the investment tax credit may be used directly to finance employee stock ownership plans. The maximum rate (11 1/2%) requires employees to match the final 1/2% contribution.

Put in its simplest terms, this portion of the investment tax credit uses public funds to increase the compensation of utility managers who choose to construct a new plant. This interpretation has not been seen as invalid by Treasury Department personnel with whom I have discussed this problem.

As an illustration with data utilized in this study, the investment tax credit reduces the company's tax liability by a sum of $275 million[1/]. Of this amount, $36 million is contributed to the stock ownership plan[2/]. In addition, the cost of administering the plan is creditable against tax liability.

The possible conditions on participation in the plans are such that utility executives will be disproportionate beneficiaries. Persons under age 25 or with less than three years employment may be excluded. Unions may elect to exclude their members from participation. Within the pool of participants, stock contributions are based upon salary up to a $100,000 limit.

Treasury Department staff believe utilities are the major beneficiaries of this program[3/].

In my opinion, this creates a major conflict of interest. Utility managers must decide the desirability of new construction programs for their companies and customers, yet if they decide affirmatively, they will be personally rewarded for doing so.

Indiana corporate income taxation

Indiana tax provisions differ in four ways. First, the rate is 3% rather than 46% on taxable income. Second, there is also a revenue tax. Third, no investment tax credit is applicable. Finally, the Indiana tax liabilities are deductions from Federal taxable income.

1/ See "investment tax credit", above.

2/ Qualifying expenditures, recall, are 95% of total. $2.5 billion x .95 x .015 = $36 million.

3/ Personal communication.

nuclear and coal generation comparison

As noted above, the minimum Asset Depreciation Range tax life is 22.5 years for a fossil fuel plant and 16 years for a nuclear plant. In addition, the repair allowance is 5% for a fossil plant rather than the 3% for a nuclear plant. In other respects there is no differentiation for tax purposes. However, to the extent that nuclear power is more capital intensive, it accrues a greater magnitude of tax subsidies per kilowatt-hour.