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NUCLEAR ECONOMICS:
TAXATION, FUEL COST AND DECOMMISSIONING

by
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Abstract

The conventional approach to nuclear power cost estimation generally uses one to four equations to represent basic assumptions regarding capital cost, operating and fuel cost, capacity utilization, return to capital, interest, and taxation. A simulation model is developed in this study to examine the time paths of economic variables and accounts. The model utilizes approximately 165 variables. The 47-year time period consists of 10 years for construction, 30 years for operations, and 7 years for decommissioning. Important assumptions for a hypothetical 1,000 MWe pressurized water reactor include (1) capital cost is $1,047 per kW in 1978 dollars, and this cost escalates at 14% per year, (2) capacity utilization follows a concave path over time, averaging 60%, (3) each component of nuclear fuel cost experiences a separate rate of inflation, (4) utility management makes maximum use of tax accounting policies, and (5) tax reductions are flowed through to utility customers.

The reference case indicates a cost in 1988 dollars of 6.86 ¢/kWh; this would be equivalent to 3.49 ¢/kWh in 1978 dollars. However, the tax subsidy (in 1988 dollars) is 3.7 ¢/kWh. The present value of tax liability is negative, and the time paths of tax liability, rate base, and net income create an economic motivation for premature construction and premature retirement of such plants. The tax provisions examined include differentiation of fuel accounting among tax, net income, and cash flow methods; exclusion of AFUDC income; investment tax credit; accelerated depreciation; California and Federal tax lives; interest deductions; dividend exclusion; capitalization of expenses; and repair allowance deductions.

The conflict of interest inherent in the investment tax credit is of particular concern. One and one-half percent of investment cost is transferred from tax liability to employee stock ownership plans. Stock contributions to employees are based upon salary. If 10,000 employees received stock based upon construction of a $2.5 billion plant, the average investment tax credit contribution would be $3,750 per employee, and utility executives would receive considerably more.

Decommissioning costs are examined with the model, and it is found that with a conventional cost assumption (e.g., 10% of original cost), the method of financing has no significant effect upon total generating cost.

However, the absence of real experience in decommissioning is a considerable obstacle to accurate analysis.

Finally, the model is used to investigate the separable and combined effects of decreasing uranium availability; higher capital, waste fuel disposal, and decommissioning costs; and tax subsidies. In this ultimate case, the cost of nuclear power is 22 ¢/kWh in 1988 dollars.

In my opinion, the Commission should begin to prepare for the possibility that neither the waste fuel problem nor the decommissioning problem will be solved at the Federal level, and these problems will become the responsibility of the State and its utilities.

Preface and Acknowledgement

The California Energy Commission is the country's leading independent regulatory agency in the fields of nuclear power regulation, energy conservation, and solar heating implementation. It has been my privilege to undertake this study of selected aspects of nuclear power economics for the Commission.

The first part of the study addressed the question of uranium availability, and was capably executed by Stephen Sullivan[1/]. This report concludes the work, and analyzes the impact of taxation, decommissioning, waste fuel, and fuel cycle costs on the overall cost of nuclear power generation.

Commission staff have always been helpful and have been positive sources of constructive criticism. Arthur Soinski (the project manager), Vincent Schwent, and Ronald Knecht (now with the California Public Utilities Commission) have been particularly valuable for their contributions and criticism.

Gwen Shearer was a competent and conscientious co-worker in California in the first stage of the study, and Dooley Kiefer has contributed insight and enthusiasm while the work was completed here in Ithaca, New York.

Finally, acknowledgement is due Professors Bingham Cady (nuclear engineering) and Robert Pohl (physics), and to Nancy Harrell (all at Cornell University) for their advice and assistance in the past year.

Preliminary versions of the sections on taxation and decommissioning in this report were previously used as the basis for testimony for the California Assembly[2/]. As a consequence of this work, the Environmental Protection Agency is sponsoring a comparative analysis of tax and and pricing subsidies for coal and nuclear power in the Ohio River Basin Energy Study.

1/ Stephen J. Sullivan, "Uranium Availability," prepared for the California Energy Commission, October 31, 1978.
2/ Duane Chapman, "Decommissioning, Taxation, and Nuclear Power Cost," California State Assembly Committee on Resources, Subcommittee on Energy, Economic Implications of the Three Mile Island Accident for California, Hearing, August 14, 1979, Los Angeles.

This report is presently in draft form, and is subject to revision and correction. Comments, criticism, and discussion are welcome.

I must, of course, reserve for myself the responsibility for errors of fact or interpretation, and for the findings and opinions expressed here.

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Introduction and Summary

This study has investigated nuclear power cost with particular emphasis upon taxation, uranium availability, decommissioning, and fuel cycle costs. An immediate problem arises in that the concept of cost is itself a matter of varying interpretation and definition.

Four concepts of cost have been examined. The first approach is the levelized cost method. Here, the purpose is to use a few equations to calculate a cost in ¢/kWh. This levelized cost is intended to represent the annual equivalent cost of the plant which, if charged to the utility's customers, would give a predetermined rate of return to stockholders while paying all costs and taxes. The major defect with this approach is its absence of explicit time analysis. This, in turn, leads to serious overestimation of tax liability and probable underestimation of the effect of inflation. The major advantage of the method is its simplicity, in that is requires a small number of numerical assumptions and relationships.

A second approach -- the real cost, or theoretical approach -- has the same goal as the levelized cost method. It seeks to define a price for electricity which, if increased each year at some constant inflation rate, would give a predetermined rate of return to stockholders while paying costs and taxes. Theoretically, this approach gives a price path which is to be preferred to the levelized cost result. The first price in the series of prices is, by definition, a constant real dollar price over the life of the facility. And, because of the iterative methods which may be used in finding this real price path, the associated rate of return to stockholders will always be equal to the intended rate. This approach has one major defect: actual regulation in practice follows a different policy with respect to price determination.

Regulatory methods of price determination constitute the third approach to cost analysis used in this study. Revenues in each year are calculated by the regulatory commission as the sum of fuel and operating costs and return to capital. The return to capital each year is based upon the rates of return to capital, expectd tax payments, and the rate base. This method shares with the real price method a dependence upon particular time values, and defines a variable price path over the utility's operating period. It differs from the real price method in two respects. First, since required revenue is the sum of one decreasing quantity (the return to capital on depreciating rate base) and two increasing quantities (fuel and operating costs rising with inflation), required revenue itself is stable in nominal dollars and declining in real dollars over much of the period. Second, since it is an attempted analytical solution rather than an iterative solution, it may not give the intended return to stockholders.

The fourth method arises from the concept of social cost, the total cost incurred by society in the production of nuclear power and the management of radioactive materials. Logically, this concept should include the full health and environmental costs of nuclear power as well as tax subsidies not reflected in the utility's production costs. However, health and environmental problems are beyond the scope of this study, so the use of the social cost concept is limited here. It represents only estimated market costs of production and tax subsidies.

The methodological technique chosen to investigate these problems of cost analysis is a simulation model of a 47-year time period. Ten years are for construction, 30 years for operations, and seven years for dismantlement. The model represents the economics of a hypothetical 1,000 MWe pressurized water reactor (PWR) which begins operations in 1988. Approximately 110 variables are examined on an annual basis, and 55 others have single values. Engineering assumptions and data are based upon other work at Cornell University and at the California Energy Commission. Individual inflation assumptions are used for investment cost, operating cost, decommissioning, and each of the seven steps in fuel acquisition.

Four algorithms for revenue and price determination are used to represent each of the four concepts of cost analysis.

Federal and California corporate income taxation are major subjects of analysis. The investment tax credit, allowance for funds used during construction, interest deductions, accelerated depreciation, and arbitrary tax lives are each represented in the model.

The conclusion is that the present worth of income tax liability on the plant is negative. While revenues will be several hundred million dollars per year, the net tax effect is negative. The magnitude of negative tax liability during construction, the first years of operation, and decommissioning is so great that it more than offsets the magnitude of positive tax liabilities in those years with actual positive liabilities. The value of the total tax subsidy is approximately $200 million per year for the hypothetical plant when the subsidy is amortizd in 1988 dollars over its operating period. One hundred such plants would require a tax subsidy on the order of $20 billion per year.

The timing of tax liabilities and after-tax profit is examined over the 47-year period, and it is seen that the pattern is such that it provides incentives for premature construction of new plants and premature retirement of existing plants.

These tax results are based upon conventional and conservative engineering cost assumptions. Higher capital cost assumptions result in greater tax subsidies.

This finding is the explanation for the current tax status of California utilities. There are three large private electric utilities in California. Examing their tax status for the past four years gives 12 instances of potential tax payment. In seven of those instances, refunds were apparently received by the companies or no payment was made.

Decommissioning was selected as a major portion of this study at its inception. The Three Mile Island accident emphasizes the importance of the subject.

In late 1977, the NRC (U.S. Nuclear Regulatory Commission) responded to an intervenor petition requesting establishment of decommissioning funds by surveying the states' policies on decommissioning finance. As of early 1978, only 10 states were able to describe their policy on decommissioning finance to the NRC. All of these 10 states used the negative salvage method. In this method, the utility is allowed to collect revenue based upon expected decommissioning costs. However, although the revenue is collected on behalf of a specific purpose, it need not be kept segregated for this purpose. The reason for this approach as seen by the Michigan Commission is that "this method has the advantage of providing an increasing cash flow to the utilities . . . for the funding of current construction programs."

Decommissioning cost estimates indicate extreme lack of experience and knowledge. Two low-cost estimates are $42 million in 1978 dollars and 10% of original expenditure. Applying inflation rates of 7% and 14% to these estimates give four future cost figures which range from $725 million to $19.6 billion. These are dismantlement estimates.

Two high-cost estimates are 24% and 100% of original investment. The four inflated future values of these estimates range from $5.7 billion to $196.1 billion.

The low-cost estimates of decommissioning costs are used in the financial analysis. Five policies are considered: (1) Decommissioning cost is paid when incurred as an ordinary expense, (2) A special fund is created, and its contributions from customers and its earnings are exempt from taxation, (3) A tax exempt fund is used; both contributions and earnings are taxable, (4) Expected future decommissioning cost is included in the rate base, and (5) The discounted present value of future decommissioning costs is included in the rate base.

For the fund approach, twelve accounts are used to examine the costs, contributions, earnings, and tax liabilities of the fund. These accounts are integrated into the complete model. Each of the four methods of price determination is used to examine decommissioning finance and its impact on overall economics.

The fourth method (rate-base inclusion of future costs) is found to result in excessive return to capital. Basically, earnings are recevied before investment is made. This method is not considered further.

There is little significant difference in total electricity cost associated with the other methods. A total variation of 2 mills per KWh in a total cost of 6.7 to 6.9 ¢/kWh is not significant.

I conclude that establishing a specific fund is the best approach, giving the best assurance of actual financial viability. Variations in customer cost are insignificant and should not be used as a basis for selection of a financial approach. This conclusion is similar to that in a recent NRC study.

However, the high-cost decommissioning assumptions give a different result. The maximum cost increase is then 4.6 ¢/kWh.

This gives strong support to Commissioner Varanini's position that current experience is needed to gain some real perspective on the problem. He has proposed immediate dismantlement of the Humboldt Bay plant.

The last section of the report might be loosly termed "doomsday economics". It examines the implications of various significant cost increases. In the preceding sections, the assumptions are conventional and conservative, in the sense that I consider them to represent the lower bounds of probable future cost.

The sensitivity analysis undertaken in this final section examines the overall consequences of cost increases in particular sectors. The theoretically correct real price algorithm is employed to determine the consequences of higher costs for uranium ore, capital investment, waste fuel disposal, and decommissioning. In addition, the consequences of dirfferent methods of fuel accounting are examined, as is the result of tax subsidy elimination.

In the worst case considered, real social cost (in 1988 dollars) has risen to 22 ¢/kWh. Capital cost is $2,094/kWe (in 1978 dollrs), uranium ore costs $155/lb in 1978, and waste fuel disposal costs $2,500/kg in 1989. Future decommissioning costs are 10% of original expenditure, and with inflation at 14% per year reach $19.6 billion. Tax subsidies are included in social cost.

In its most literal sense, this latter case is unrealistic. It is difficult to imagine a viable nuclear power industry with this level of social and market cost. The qualitative factors underlying the quantitative assumptions can be viewed as representing a major increase in safety design cost, a depletion of high-grade domestic uranium ore, continued lack of resolution of the waste fuel disposal problem, and the development of difficult obstacles to acceptable reactor decommissioning.

Suppose each assumption is assigned a one in three probability. The result is that this combination has a one in 81 probability of occurring. As low as this is, it is considerably higher than the probability would have been thought to be at the inception of this study.

The conclusions and recommendations which I make to the Commission as a result of this study are as follows:

(1) Cost analysis methods are less uniform than is generally supposed, and different methods give quite different results. The levelized cost approach is wholly inadequate to examine tax and inflation effects.

(2) The present worth of tax liability on revenue from a new nuclear plant is negative. This general pattern, being similar for all utility investments, has caused the current situation wherein California's large utilities generally do not make current income tax payments.

(3) The timing of tax subsidies is such that incentives are created for premature construction and premature retirement of generating facilities.

(4) The employee stock ownership plan interacts with the investment tax credit to increase the personal compensation of utility managers undertaking new construction projects.

(5) With conventional low-cost assumptions about future decommissioning finance, the funding approach is to be preferred because of the assurance it creates for future fund availability.

(6) Unconventional high-cost assumptions for decommissioning impose major cost increases on customers. Actual dimantlement of the Humboldt Bay reactor is desirable to gain current experience.

(7) Social cost and sensitivity analysis gives a low probability that nuclear power cost may be as high as 22 ¢/kWh in 1988 dollars.

In my opinion, the Commission should begin to consider the possiblity that neither the waste fuel problem nor the decommissioning problem will be solved at the Federal level, and these problems will increasingly devolve upon the States and their utilities.

As a consequence of this study, I conclude that the conventional levelized cost approach should be modified in these ways: (1) Explicit recognition should be given to the existence of negative levelized tax liability, and (2) Decommissioning finance should be analyzed in the context of toal costs.

With respect to future research, two problems seem of unusual significance: (1) On decommissioning finance: should income and asset accounting be revised and standardized for tax, regulatory, and company accounting? How can regulatory commissions prepare for the possibility of very large future costs? (2) How significant is the influence of tax subsidies on other energy forms? Is the expected tax liability on a coal-fired power plant, a LNG plant, or a refinery also negative? How large a role do those public-money subsidies to private corporations play in stimulating growth in conventional energy usuage?

SECTION 1. COST ANALYSIS METHODS

1A. Levelized Cost

The calculation of levelized or constant real cost per kilowatt hour has been an important part of the conventional approach to nuclear economics. By providing a single cost figure in cents per kilowatt hour, analysts have attempted to simplify economic decision-making. Thus, if plant type A is said to cost 4 ¢/kWh of generation, and plant type B appears to cost 3 ¢/kWh, then decision-makers logically choose B.

In its simplest form, the levelized approach requires only five assumptions: fixed charge rate, capital cost per kWe, capacity factor, fuel cost, and operating cost. For example, in the Rossin/Rieck Science article[1/], these assumptions are: 20% fixed charge rate, $692/kWe captial cost, 60% capacity factor, 7 mills/kWh fuel cost, and 2 mills/kWh operating cost. Nuclear power cost, then, is 3.5 ¢/kWh in 1977 dollars[2/].

A more complex and accurate single equation approach was originated by K. A. Gulbrand and P. Leung[3/]. It has been developed in greater detail by the California Energy Commission and others[4/].

It can be represented by Eqs. (1)-(4)

$$C = \frac{K*fcr*100}{8766*cf} + OM + FUEL + DEC \qquad (1)$$

$$fcr = crf + adm + ins + ptx + tax \qquad (2)$$

$$r = b*d + rc*c + rp*p \qquad (3)$$

$$tax = \frac{f}{1-f}\left[\left(\frac{r-db}{r}\right)(crf-sl) - (pwad*crf - sl) - ic\right] - ic \qquad (4)$$

In these four equations, a capital letter represents a cost (e.g., $/kWe or ¢/kWh) and lower case letters denote fractions, rates, or constants. Here, C is generating cost in constant real dollars (¢/kWh), K is capital cost in $/kWe, and fcr is the fixed charge rate applied to capital cost charge, again in ¢/kWh. Dollars are converted to cents by multiplying by 100, and the product of the capacity factor (cf) and 8766 hours per year gives kWh/kWe per year.

OM is annual operating and maintenance cost, FUEL is fuel charge, and DEC is decommissioning cost; each term is in ¢/kWh. (It is uncommon for the decommissioing cost term in Eq. (1) to be made explicit.)

In Eq. (2), the fixed charge rate (fcr) equals the sum of the capital. recovery factor (crf), administrative cost (adm), insurance (ins), property tax liability (ptx), and State and Federal income tax liability (tax)

The capital recovery factor is always $crf = r(1+r)^n/((1+r)^n-1)$ where r is the rate of return from Eq. (3) and n is project life. In other contexts, crf may be termed the annuity factor or the amortization factor. It is equal to the sum of the rate of return and the sinking fund factor.[5/].

Eq. (3) shows that the rate of return r equals the weighted average of the bond rate (b), the return to common stock (rc), and the return to preferred stock (rp). Each term is weighted by the proportion of capital provided by each source: d (debt), c (common stock), and p (preferred stock).

Finally, Eq. (4) shows how tax liability is presumed to be affected by the tax rate (f)[6/], the rate of return, the proportion of debt in capital for the new plant, the bond rate, capital recovery in excess of straight line depreciation (crf - sl), the present worth of accelerated depreciation deductions (pwad), the amortized value of these deductions in excess of straight line depreciation (pwad*crf - sl), and the amortized value of the investment tax credit (ic).

As given by these three relationships, the resulting levelized costs in cents per kWh is presumed to be the price which, if charged for each kWh over the operating life of the facility, would exactly pay allowed return to owners, taxes, and the various components of costs in Eqs. (1)-(4). Application of these relationships to different fuel types such as coal or nuclear power then allows these processes to be ranked according to apparent minimum cost to the utility and its customers.

Appendix A to this report gives the derivation of the Gulbrand-Leung method from basic accounting principles.

Parenthetically, I may note that the studies cited here have not considered the possibility of the tax liability in Eq. (4) being negative. The only acknowledgement of this possibility is in other work by this analyst for the California Energy Commission[7/].

1B. Pure Theory and Real Cost

A second approach to the definition of annual cost is based upon the theory of rate regulation. Investors should receive a return on their investment in utilities which is equal to the return which would have been realized by comparable investment in other activities of equivalent risk. For example: if investment in a utility has identical risk to investment in other large corporations, then the return should be identical. If normal investment provides a 13% annual rate of return on stock equity, then the return to utility investors in the sense of corporate net income should be at 13%. (The motivation for selecting 13% as an illustration is explained below.)

Suppose utility equity investment required $500 million this year and $500 million next year. If these amounts were invested in average corporations, the future accumlated amount at the end of the next 30 years (following the two years of investment) would be \$47.074 billion at this 13% return.

We may state the theoretical revenue requirement simply: what net revenue per kWh must be collected each year for 30 years to result in the same future amount of \$47.074 billion? In the context of this discussion, this price -- whatever it may be -- will provide a fair rate of return.

Let us further suppose that this equity investment is associated with a 600 MWe plant, and that loan funds have provided an additional and equal investment of \$500 million in each of two years. If the plant operates at 65% capacity, it will generate 3.42 billion kWh per year. Net revenue here means gross revenue less fuel cost, operating cost, tax payments, and interest payments. So, the levelized net revenue requirements will be \$160.6 million per year, or 47.0 mills per kWh. This net revenue -- \$160.6 million per year -- will, at 13% interest valuation, grow to an accumulated \$47.074 billion.

In application to this analysis, we take the actual equity investment in the construction period, V_t, and let it accumulate at the after-tax stockholders' equity rate of return (ser) throughout the construction, operation, and decommissioning periods. Therefore,

$$\Pi_n = \sum_{t=1}^{n} V_t(1 + ser)^{n-t} \qquad (5)$$

$_n$ represents the accumulated profit at the fair rate of return for investors for the actual equity investments V_t. (V_t is positive only during the construction period.)

This, in turn, must be related to specific assumptions about inflation, capacity utilization, fuel cycle costs, operating costs, debt cost, taxes, and decommissioning costs. A statement of this is

$$\Pi_n = \sum_{t=1}^{n} [P_{q1}(1+f_q)^{t-1}Q_t - \sum_{j=1}^{m} P_{xj1}(1+f_{xj})^{t-1}X_{jt} - I_t - T_t][(1+ser)^{n-t}] \qquad (6)$$

P_{qo} is original price for electricity, \$/kWh. Inflation in this price is at 100 f_q% per year, so the term $P_{qo}(1+f_q)t$ represents the assumed future price of electricity. Q_t is generation which may vary in each year. P_{xj1} is the first year's price for cost component X_j, and f_{xj} is the escalation rate. There are m cost categories which include construction costs, fuel costs, operating cost, and decommissioning and waste fuel costs. I_t represents interest expense, and T_t is income tax expense. The equity rate of return, ser, is calculated on the basis of capital structure and rates of return for common and preferred stock.

Eqs. (5) and (6), then, provide the basis for a simulated solution to the rate of return problem for a long time horizon, 45-50 years. It is dynamic, in the sense that comparisons can be made between cases having wide variations in time paths, magnitudes, and signs of particular assumptions. Each problem is solved for P_{q1}; this gives a price which, inflated at the general inflation rate, will generate actual after-tax profit equal to the fair rate of return. P_{q1}, then, is the theoretically correct real price of electricity for any particular set of assumptions.

The levelized cost method for C in Eqs. (1)-(4) is an approximation of the real cost P_{q1} in Eqs. (5) and (6).

1C. Regulatory Behavior

The actual principles of regulatory rate determination are quite different from the levelized cost or real cost methods described above. Rate setting allows for immediate recovery of expenses, and bases capital recovery on the rate of return applied to normally depreciated investment.

In the "pure theory" discussion, P_{q1} defined a real price, constant over the the operating period. With general inflation at 100 f_q% annually, nominal price was $P_{qt} = P_{q1}(1+f_q)^{t-1}$.
Now, in the rate base method, price is revenue per unit output:

$$P_{qt} = REV_t / Q_t \tag{7}$$

Revenue (REV) each year is the sum of a return to capital (CARR), annual operating, maintenance, administration, and insurance costs (OM), a fuel charge (FUEL), and a decommissioning charge (DEC):

$$REV_t = CARR_t + OM_t + FUEL_t + DEC_t \tag{8}$$

The return to capital in each year is based upon undepreciated capital, rates of return to debt and equity, and expected tax payments:[8]

$$CARR_t = CR_t + TF_t + TS_t + PTX_t \tag{9}$$

CR is capital recovery and TF and TS are expected Federal and State income taxes. PTX is expected property tax.

Capital recovery in each year is the sum of returns to debt, to preferred and common stock, and normal depreciation:

$$CR_t = b*RB_t*d + rc*RB_t*c + rp*RB_t*p + sl*RB_o \tag{10}$$

Included here are the bond rate b, the after-tax return to common and preferred equity (rc and rp), and the proportions of captial which are debt (d), common equity (c), and preferred equity (p). The straight line depreciation is sl.

The rate base (RB) may be mid-year values for returns to debt and equity, and beginning-of-year values for depreciation.

Note that the pure theory method of real price determination defines a regularly rising nominal cost per kWh, while the capital recovery component of actual rate setting is continuously declining. As shall be seen in later sections, this has significant tax implications.

Expected Federal and State taxes are defined by Eqs. (11) and (12).

$$TF_t = (CR_t - b*RB_t*d - FTXDP_t) * \frac{ftr}{1-ftr} \tag{11}$$

$$TS_t = (CR_t - b*RB_t*d - CTXDP_t + TF_t) * \frac{ctr}{1-ctr} \tag{12}$$

In Eq. (11), the new terms are FTXDP, depreciation for Federal tax purposes, and ftr, the Federal corporate income tax rate, now 46%. Both Federal and California tax depreciation permit the double declining balance method to be used in conjunction with artificial tax lives. For tax purposes, the minimum Federal life is 16 years for a nuclear project and the minimum California tax life is 20 years[9/].

In Eq. (12), CTXDP is California depreciation for tax purposes and ctr is the California tax rate, now 9%.

1D. Social Cost and Tax Subsidies

The preceding three sections have defined power cost as if cost to the utility were the only perspective of interest. While each of these three methods will give distinctly different versions of cost timing and amounts, each excludes economic costs which are incident upon other economic agents.

From a national perspective, cost of power production includes tax subsidies, pricing subsidies, the cost of public health and environmental impact of power generation, and the cost of displaced consumption and investment.

Social cost is the total cost society incurs in the production of a commodity; it is the utility's market cost of production as well as these non-market costs.

In this study, considerable attention is given to a single facet of the non-market costs of power production, this being tax subsidies. This does not mean the other non-market factors are considered to be unimportant, but they are beyond the scope of this work.

If the Federal government were to appropriate some amount of funds for the construction of a power plant by a utility, this would be termed a subsidy. We should hope that it meets the general definition: a grant of public monies to a private enterprise in order to promote some result which benefits the public welfare.

A tax subsidy is analogous in meaning: it is a reduction in tax payment granted in return for certain actions which are presumed to promote the public good. The Congressional Budget Act of 1974 uses this definition of a tax expenditure: "revenue losses attributable to provisions of the Federal tax laws which allow a special exclusion, exemption, or deduction from gross income, or which provide a special credit, a preferential rate of tax, or a deferral of tax liability"[10/]. Tax subsidy and tax expenditure are equivalent concepts.

In section 4, below, it will be shown that the tax subsidies flowing to nuclear power generation are of considerable magnitude.

Notes and References for Section 1.

1. A. D. Rossin and T. A. Rieck, "Economics of Nuclear Power," Science, 18 August 1978, 201: 582-589.

2. Decommissioning was estimated at two-tenths of a mill per kWh, and waste disposal at one-half mill per kWh.

3. K. A. Gulbrand and P. Leung, "Power System Economics," Journal of Engineeing for Power, October, 1975, pp. 465-472.

4. Ronald L. Knecht, Review and Critique of California Electricity Generation Methods Assessment Project, May 1, 1977, and TRW Energy Systems Management Division, California Electricity Generation Methods Assessment Project, January 30, 1977; both prepared for the California Energy Commission. See also Mitre Corporation, "Report on Levelized Busbar-Costing Workshop," Appendix to A Comparative Analysis of Energy Costing Methodologies, 1978.

5. The sinking fund factor is $sf = r/((1+r)^n - 1)$; $crf = r + sf$.

6. The income tax liability on corporate income is the result of the interaction of State and Federal rates. In California, $f = .09 + .46 (1-.09)$. The California tax is deductible from Federal taxable income.

7. Duane Chapman, "Taxation and Solar Energy," California Energy Commission, June, 1979 (available from the Commission's Publications Unit).

8. Equations (9) - (12) are adapted from Ron Knecht, "Fixed Charge Rate Model," CEC Memorandum, July, 1978, and 20 March 1979.

9. More precisely, the Federal rate is 17% of the first $25,000 of taxable income; 20% of the next $25,000; 30% of the next $25,000; and 46% of taxable income exceeding $100,000. The California rate is 9% but not less than $200. See Commerce Clearinghouse, Internal Revenue Code, 1978, Section 11(b), and California Franchise Tax Board," Corporation Tax Forms and Instructions," 1978, p. 4. Permissible tax lives are given in U.S. Internal Revenue Service, "Tax Information for Depreciation," Publication 534, 1979. Federal policy permits the lower limit lives, while California policy apparently sets the guideline period as the minimum life. The investment tax credit would be included in Equation (11); see Section 4, below.

10. See U.S. Office of Management and Budget, Special Analyses: Budget of the United States Government, Fiscal Year 1979, p. 148. This definition is included in the material appended to "Taxation and Solar Energy," op. cit. pp. A-40, 41.

SECTION 2. THE PLANT AND FUEL CYCLE MODEL

The model discussed here examines the major economic accounts and variables for a hypothetical nuclear power plant over a 47-year period. The basic purposes of the model are to investigate (1) the effect of Federal and State tax policy on nuclear power costs; (2) the significance of decommissioning cost assumptions for power cost and the interaction of decommissioning finance and tax policy; (3) the sensitivity of costs to variation in certain assumptions, particularly (a) type of regulation, (b) uranium availability, (c) nuclear waste disposal, and (d) fuel cost accounting; (4) the possible magnitude of future market cost with most likely assumptions as viewed by the author; and (5) social cost of nuclear power in the limited sense of market cost and tax subsidies. Each problem is examined in subsequent sections.

The model itself reports approximately 110 variables on an annual basis and 55 others which do not change over time. Each of the 165 variables is defined in Appendix B1, and the program and a single problem printout are Appendices B2 and B3. These three appendices are attached to this report.

Section 2 of the report describes the most important structural aspects and assumptions of the model and the hypothetical plant. Subsequent sections discuss the analysis and its implications.

The major characteristics of the assumed plant are that its net capacity is 1,000 MWe, it uses a pressurized water reactor with an equilibrium burnup rate of 32.6 MW days per kg of uranium, its maximum annual capacity factor is 65%, and it has a 30-year operating period.

The engineering assumptions are taken from Cady and Hui's "NUFUEL"[1/], while much of the cost and price assumptions are from Ronald Knecht's previous work for the California Energy Commission[2/].

2A. Plant Construction Costs

The Three Mile Island accident reduces the usefulness of existing capital cost estimates for nuclear power plants. It is premature to offer quantitative speculation about the accident's impact upon future costs.

In this study, I simply use the highest engineering estimate known to me, $1,047 per kWe[3/]. This estimate precedes the Three Mile Island accident. Other estimates are much lower but no longer seem relevant [4/]. It may be of interest to note that application of the Komanoff equation gives a statistical estimate of $1,070 per kWe[5/] in 1978 dollars.

Future inflation in nuclear power construction cost is assumed to be 14% per year from 1978 through 1987. This rate is equally divided between a general inflation rate of 7% per year and an additional escalation rate for nuclear plant of 7% per year.

In my opinion, 14% inflation in nuclear power costs in a current 10-year period will in the future be seen as erroneously low. CEC analysis has previously shown increases in nuclear plant costs in dollars per kWe to have increased 22% per year in the 1971-76 period[6/]. The CEC analysis, of course, predated the Three Mile Island accident which, in my opinion, necessarily imparts a positive force to nuclear power plant cost escalation.

A second force raising capital costs will be cost escalation in electricity and fossil fuel prices. Nuclear power plant fabrication is itself energy intensive, and cost escalation in other energy forms raises nuclear plant costs.

Table 1 shows basic construction cost data. Construction work in progress does not include AFUDC (allowance for funds used during construction) which is shown separately in the Table. AFUDC is compounded and applied to mid-year values. The AFUDC rate of 8% is believed to be representative of California utilities considering new facilities[7/].

The second column, based upon Comtois's work[8/], indicates the time distribution of investment expenditures over a 10-year period. The four-tenths of 1% value for 1978 suggests that the plant may be viewed as having entered the permit application phase in 1978 with major construction costs anticipated in 1983 and thereafter until construction is completed in 1987.

Columns 7-9 show borrowing and debt. One-half of the construction cost is borrowed each year, and interest payments at 9.5% are made on cumulative debt.

Cumulative cost with AFUDC is equivalent to the cost which will enter the rate base at the beginning of 1988, and has reached $3.112 billion at the end of 1987. This is $3,112 per kWe.

Table 2 shows basic financial parameters: common equity is 35% of investment, preferred equity is 15%, and debt is 50%. The costs of capital

Table 1. Representative Nuclear Power Plant Cost Data

(million dollars, except columns 1 and 2)

(1) Year	(2) Proportion of investment	(3) Actual investment expenditures	(4) Cumulative investment	(5) AFUDC	(6) Cumulative investment with AFUDC	(7) New borrowing	(8) Cumulative debt	(9) Interest payments
1978	0.004	4.188	4.188	0.168	4.356	2.094	2.094	0.199
1979	0.005	5.968	10.156	0.587	10.911	2.984	5.078	0.482
1980	0.010	13.607	23.763	1.417	25.934	6.803	11.881	1.129
1981	0.009	13.961	37.723	2.633	42.528	6.980	18.862	1.792
1982	0.019	33.598	71.322	4.746	80.873	16.799	35.661	3.388
1983	0.111	223.765	295.087	15.420	320.058	111.883	147.543	14.017
1984	0.240	551.551	846.637	47.667	919.276	275.775	423.319	40.215
1985	0.432	1131.782	1978.419	118.813	2169.871	565.891	989.209	93.975
1986	0.112	334.504	2312.923	186.970	2691.344	167.252	1156.461	109.864
1987	0.058	197.477	2510.400	223.207	3112.028	98.738	1255.200	119.244

Note: Actual investment expenditures equal \$1,047 million x 1.14^{k-1} x C_k, k being years from 1977 and C being the proportion of investment from column 1. \$1,047 is the cost per kWh in 1978 dollars. Column 4 sums column 3. AFUDC equals 8% of the sum of one-half of actual current expenditure (column 3) plus the cumulative investment with AFUDC (column 6).

New borrowing (column 7) is 50% of column 3. Cumulative debt (column 8) is the end-of-year sum of previous debt (column 8) and new borrowing (column 7). Interest payments (column 9) are 9.5% of cumulative debt.

Table 2. Basic Financial Assumptions

Type of capital	Cost or Rate of return	Proportion of capital
Common equity	14%	35%
Preferred equity	9.5%	15%
Combined equity	12.65%	50%
Debt	9.5%	50%
Combined rate of return	11.075%	100%
Allowance for funds used during construction	8%	--

for each equity component are, respectively, 14%, 9.5%, and 9.5%. Overall equity return is 12.65%[9], and each equity return is considered to be an after-tax goal for the utility and the regulatory commission.

Equity expenditures and debt each total $1.255 billion at the end of 1987. However, if the equity funds alone had been invested each year at the overall equity rate of return of 12.65%, the accumulated value would stand at $1.654 billion. This is equivalent to the "pure theory" return in Section 1B.

The tax implications of Table 1 are of considerable interest, but such discussion is deferred to Section 4. In this section, basic cost and engineering relationships in the model are summarized.

2B. The Nuclear Fuel Cycle: Quantities, Prices, Accounting

Fuel cycle requirements in Table 3 for the hypothetical facility are from Cady and Hui. Generally, price and inflation assumptions are from Knecht[10] and Commission work, and are shown in Table 4.

Since general inflation is currently 9% per year[11], the Table 4 inflation assumptions are hardly excessive. Considering the energy-intensive nature of fuel manufacture, energy-induced general inflation must certainly affect nuclear fuel costs.

In my opinion, the assumptions in Table 4 are more appropriately described as "conventional" as opposed to "realistic".

The reactor core operates on three loadings, one of which is replaced each year of normal operation. There are 32 batches. The first and thirty-second are used for one year each, the second and thirty-first for two years each, and the other batches (#3-#30) are each used for three years.

Uranium enrichment is assumed to take feed at 0.75% U^{235} and result in a product which has been enriched to 3.2% and tails with a concentration of 0.25%.

Table 5 shows the time distribution of assumed expenses in each stage of the fuel cycle. These are derived from the data in Tables 3 and 4 and the assumption of three batches, each utilized for 36 months, and annual fuel reloading. Except as otherwise noted in the sensitivity analysis, the values in Tables 3-5 are common to every analysis.

Three accounting methods are used to determine fuel expense. The simplest is actual expenditure, the last column in Table 5. It is the sum of the seven individual phases. In years in which fuel is being prepared for equilibrium operation, the annual expenditure rises from $75 million in 1988 to $571 million in 2014.

A second accounting method is amortization. Amortized fuel expense allocates to each of the 32 batches the uranium oxide, conversion, fresh fuel transportation, enrichment, fabrication, spent fuel transportation,

Table 3. Nuclear Fuel Cycle Equilibrium Annual Quantities and Lead and Lag Times

Fuel Cycle Component	Variable Name	Equilibrium Annual Quantities	Lead (+) or Lag (-) years from first use
uranium oxide	QUOX	456,133 lb U	+3
conversion	QCON	173,300 kg U	+3
enrichment	QNRICH	114,127 SWU	+2
fabrication	QFAB	27,143 kg U	+1
fresh fuel transportation	QFRTRN	27,143 kg U	+2
spent fuel transportation	QSPTRN	27,143 kg U	-3
waste disposal	QWASTE	27,143 kg U	-3

Source: Cady and Hui for quantities; "Comparative Cost Analysis Revised" for lead and lag times.

Table 4. Nuclear Fuel Price and Inflation Assumptions

Fuel Cycle Component	Variable Name	Original Price 1977	Inflation Assumption	Future Price 1989
uranium oxide	PUOX	$43/lb U a/	8%	$103.30/lb U
conversion	PCON	$3.71/kg U	6%	$7.46/kg U
enrichment	PNRICH	$98.30/kg SWU in 1979 b/	8%	$212.22/kg SWU
fabrication	PFAB	$100.70/kg U	6%	$202.63/kg U
fresh fuel transportation	PFRTRN	$16/kg U	6% for 7 years, then 4.5%	$29.98/kg U
spent fuel transportation	PSPTRN	$16/kg U	6% for 7 years, then 4.5%	$29.98/kg U
waste disposal	PWASTE	$106.50/kg U c/	8% for 7 years, then 6.5%	$250/kg U

Source:

a/ U.S. Department of Energy, Weekly Announcements, December 12, 1978, p. 4, reports average market prices of $43.65 for the first half of 1978.

b/ The U.S. Department of Energy has announced this charge applicable for 1979. Knecht had projected $96.99 for "requirements contracts". U.S. Department of Energy, Weekly Announcements, October 31, 1978, p. 2.

c/ The 1977 value of $106.50 is implied by assuming a $250 value in 1989.

Table 5. Assumed Costs of Nuclear Fuel (million dollars)

Year	Uranium oxide (CUOX)	Conversion (CCON)	Fresh fuel transport (CFRTRN)	Enrichment (CNRICH)	Fabrication (CFAB)	Waste fuel transport (CSPTRN)	Waste fuel disposal (CWASTE)	Total actual expenditures
1978–84	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1985	108.925	3.080	0.000	0.000	0.000	0.000	0.000	112.004
1986	39.213	1.088	2.139	57.681	0.000	0.000	0.000	100.121
1987	42.350	1.153	0.745	20.765	14.685	0.000	0.000	79.698
1988	45.738	1.223	0.779	22.426	5.189	0.000	0.000	75.354
1989	49.297	1.296	0.814	24.220	5.500	0.814	6.786	88.826
1990	53.349	1.374	0.850	26.158	5.830	0.850	7.227	95.638
1991	57.616	1.456	0.889	28.251	6.180	0.889	7.697	102.977
1992	62.226	1.544	0.929	30.511	6.551	0.929	8.197	110.885
1993	67.204	1.636	0.970	32.952	6.944	0.970	8.730	119.406
1994	72.580	1.734	1.014	35.588	7.360	1.014	9.297	128.588
1995	78.387	1.838	1.060	38.435	7.802	1.060	9.901	138.482
1996	84.657	1.949	1.107	41.510	8.270	1.107	10.545	149.145
1997	91.430	2.066	1.157	44.830	8.766	1.157	11.230	160.637
1998	98.744	2.190	1.209	48.417	9.292	1.209	11.960	173.022
1999	106.644	2.321	1.264	52.290	9.850	1.264	12.738	186.370
2000	115.176	2.460	1.321	56.473	10.441	1.321	13.566	200.756
2001	124.390	2.608	1.380	60.991	11.067	1.380	14.447	216.263
2002	134.341	2.764	1.442	65.870	11.731	1.442	15.387	232.977
2003	145.088	2.930	1.507	71.140	12.435	1.507	16.387	250.993
2004	156.695	3.106	1.575	76.831	13.181	1.575	17.452	270.414
2005	169.231	3.292	1.646	82.978	13.972	1.646	18.586	291.349
2006	182.769	3.490	1.720	89.616	14.810	1.720	19.794	313.918
2007	197.391	3.699	1.797	96.785	15.699	1.797	21.081	338.248
2008	213.182	3.921	1.878	104.528	16.641	1.878	22.451	364.478
2009	230.236	4.156	1.962	112.890	17.639	1.963	23.910	392.756
2010	248.655	4.406	2.051	121.921	18.697	2.051	25.465	423.245
2011	268.547	4.670	2.143	131.675	19.819	2.143	27.120	456.117
2012	290.031	4.950	2.239	142.209	21.008	2.240	28.882	491.560
2013	313.234	5.247	2.340	153.586	22.269	2.340	30.760	529.775
2014	338.292	5.562	2.445	165.873	23.605	2.446	32.759	570.981
2015	0.000	0.000	2.556	179.143	25.021	2.556	34.889	244.164
2016	0.000	0.000	0.000	0.000	26.522	2.671	37.156	66.349
2017	0.000	0.000	0.000	0.000	0.000	2.791	39.571	42.362
2018	0.000	0.000	0.000	0.000	0.000	8.750	126.431	135.180
2019–24	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000

and waste disposal costs associated with each batch. Each batch is amortized uniformly over the years it is in the reactor. Batches #1 and #32 are wholly amortized in a single year. Batches #2 and #31 are each 50% amortized in each of the two years they are in the reactor core. For batches in equilibrium operation, the relationship between batch cost and actual expenditure is shown by Eq. (13) with CBATCH (J) being the cost of batch J.

$$\begin{aligned} CBATCH(J) &= CUOX(J+5) + CCON(J+5) + CNRICH(J+6) \\ &\quad + CFRTRN(J+6) + CFAB(J+7) + CSPTRN(J+11) + CWASTE(J+11) \\ &\qquad J = \text{batches } 4,\ 30 \end{aligned} \tag{13}$$

Batch #3 is used for three years but shares acquisition costs with batches #1 and #2. similarly, batch #31 is used for three years but shares spent fuel and disposal costs with batches #32 and #33.

In equilibrium, fuel expenses are amortized as shown in Eq. (14).

$$AMFUEL(K) = (CBATCH(K-10) + CBATCH(K-9) + CBATCH(K-8))/3 \tag{14}$$

AMFUEL(K) is fuel cost as amortized in year k, shown as column 1 in Table 6.

In the illustrated case, no interest-type allowance is made for fuel inventory during the operating period. However, an AFUDC account for fuel is used during the construction period years 1985-87 to accumulate a rate base component of AFUDC for fuel. In the capital accounts analysis, the allowance for funds used during construction (AFUDC) was calculated at an 8% annual rate. The same 8% rate is used in determining the allowance for funds invested in fuel during the construction period.

This becomes "fuel rate base" in Table 6 at $39.4 million at the beginning of operations in 1988. It is uniformly depreciated at $1.3 million per year over 30 years and this is an allowable expense for rate setting.

The third method of accounting for fuel expense is that required by the IRS (Internal Revenue Service). Basically, the IRS follows a traditional cost of goods sold approach. Consequently, it does not recognize fuel AFUDC or its depreciation, nor does it permit spent fuel transportation and disposal costs to be claimed in years before they are actually incurred.

For tax purposes, then, batch costs must exclude the latter two components of Eq. (13). The tax equations analogous to Eqs. (13) and (14) are:

$$\begin{aligned} CCBAT(J) &= CUOX(J+5) + CCON(J+5) + CNRICH(J+6) \\ &\quad + CFRTRN(J+6) + CFAB(J+7) \qquad J = \text{batches } 4,\ 32 \end{aligned} \tag{15}$$

Table 6. Amortizing Fuel Cost, Fuel Rate Base, and Tax Deductions (million dollars)

Year	Amortized fuel expense (AMFUEL)	Fuel rate base (FUEL RB)	Tax deductible fuel expense (FUEL DED)
1978	0.000	0.000	0.000
1979	0.000	0.000	0.000
1980	0.000	0.000	0.000
1981	0.000	0.000	0.000
1982	0.000	0.000	0.000
1983	0.000	0.000	0.000
1984	0.000	0.000	0.000
1985	0.000	0.000	0.000
1986	0.000	4.480	0.000
1987	0.000	17.804	0.000
1988	120.470	39.386	113.978
1989	83.675	38.073	81.741
1990	76.094	36.760	75.203
1991	82.056	35.447	80.929
1992	88.295	34.135	87.097
1993	95.014	32.822	93.739
1994	102.250	31.509	100.894
1995	110.043	30.196	108.601
1996	118.436	28.883	116.902
1997	127.477	27.570	125.845
1998	137.215	26.257	135.480
1999	147.705	24.944	145.859
2000	159.005	23.632	157.041
2001	171.178	22.319	169.089
2002	184.292	21.006	182.070
2003	198.421	19.693	196.057
2004	213.644	18.380	211.129
2005	230.045	17.067	227.370
2006	247.718	15.754	244.872
2007	266.760	14.442	263.732
2008	287.279	13.129	284.058
2009	309.390	11.816	305.963
2010	333.219	10.503	329.573
2011	358.898	9.190	355.019
2012	386.573	7.877	382.445
2013	416.400	6.564	412.008
2014	448.546	5.251	443.873
2015	513.234	3.939	478.222
2016	642.436	2.626	600.552
2017	1078.805	1.313	1008.517
2018	0.000	0.000	135.180
2019	0.000	0.000	0.000
2020	0.000	0.000	0.000
2021	0.000	0.000	0.000
2022	0.000	0.000	0.000
2023	0.000	0.000	0.000
2024	0.000	0.000	0.000

$$\text{CAMFU(K)} = ((\text{CCBAT(K-10)} + \text{CCBAT(K-9)} + \text{CCBAT(K-3)})/3 + \text{CSPTRN(K)} + \text{CWASTE(K)} \quad (16)$$

In Eq. (15), CCBAT(J) is the tax cost of batch J. In Eq. (16), CAMFU(K) is the tax deductible amortization of fuel expense in year K. Equation (16) describes tax amortization of fuel expense for the years 1990-2019. CAMFU is appropriately defined for the other four years. The tax amortization of fuel expense deductions is the last column in Table 6.

2C. Capacity Utilization and Operating Expense

Ronald Knecht suggested that capacity utilization be assumed to begin at 55% in 1988, growing 2% per year until 65% is reached in 1993. This level is maintained for 10 years, and utilization declines at 1% per year for the remaining 15 years[12].

This may be compared to the capacity factors derived from Komanoff's analysis of PWR experience[13]. He finds that utilization is greater for reactors completed after 1973, that utilization increases with the age of the reactor, and declines with size. Komanoff's analysis would project a 1988 capacity factor of 45.9%, and a 1993 value of 63.3%. Utilization would continue to increase until an 82.7% factor was achieved in 2017, the last year of operation.

In my opinion, Knecht's judgement on declining utilization in the latter term of reactor life is more sensible than continuous improvement. As a plant ages, the assumption is that it will be displaced in base load operations by newer, more efficient plants. It should be noted that Komanoff's analysis contained no plants older than 10 years.

Assumed operating and maintenance (OM) costs reflect three terms. One factor is administrative and insurance cost, this being 1.5% of accumulated investment (including AFUDC) at the beginning of plant operations. A second factor is capacity-related OM, this being \$7 per kWe in 1977 dollars. A third OM factor is output-related, and is .3 mills per kWh (in 1977 dollars) of maximum generation. The latter two factors are escalated by specific inflation assumptions of 6% annually to 1984, then 4.5% thereafter. In summary:[14]

$$OM(k) = .015*RB_o + (.3*5.698 + 7)(1.06)^7(1.045)^k \quad (17)$$

$$k = 11, 40$$

The result is an annual administrative, insurance, operations, and maintenance cost (OM) which is \$62.3 million in 1988 and grows at 4.5% per year. RB_o in Eq. (17) is original rate base as above.

Table 7 gives the capacity utilization, generation, and operating cost assumptions which are employed in the analysis.

Table 7. Capacity Utilization, Generation, and Operating Costs

Year	Capacity utilization (%)	Generation (billion kWh)	Operating costs (million dollars)
1978	0	0.000	0.000
1979	0	0.000	0.000
1980	0	0.000	0.000
1981	0	0.000	0.000
1982	0	0.000	0.000
1983	0	0.000	0.000
1984	0	0.000	0.000
1985	0	0.000	0.000
1986	0	0.000	0.000
1987	0	0.000	0.000
1988	55	4.821	62.296
1989	57	4.997	65.099
1990	59	5.172	68.028
1991	61	5.347	71.089
1992	63	5.523	74.288
1993	65	5.698	77.631
1994	65	5.698	81.125
1995	65	5.698	84.775
1996	65	5.698	88.590
1997	65	5.698	92.576
1998	65	5.698	96.742
1999	65	5.698	101.096
2000	65	5.698	105.645
2001	65	5.698	110.399
2002	65	5.698	115.367
2003	64	5.610	120.558
2004	63	5.523	125.983
2005	62	5.435	131.652
2006	61	5.347	137.576
2007	60	5.260	143.767
2008	59	5.172	150.237
2009	58	5.084	156.997
2010	57	4.997	164.062
2011	56	4.909	171.445
2012	55	4.821	179.159
2013	54	4.734	187.222
2014	53	4.646	195.646
2015	52	4.558	204.450
2016	51	4.471	213.650
2017	50	4.383	223.264
2018	0	0.000	0.000
2019	0	0.000	0.000
2020	0	0.000	0.000
2021	0	0.000	0.000
2022	0	0.000	0.000

This section has described the main elements and assumptions of the engineering, economic, and accounting relationships employed in the plant and fuel cycle components of the study. Appendix B shows the full model, a sample printout, and gives definitions of all program variables and printout heading labels.

The following Section describes the algorithms by which prices are determined.

Notes and References for Section 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, Ward Laboratory of Nuclear Engineering, Ithaca, N.Y., August, 1978.

2. Several CEC publications and memoranda by Knecht and coauthors are utilized throughout this report. In addition to "Review and Critique" cited above, they are "A. B. 1852 Baseline Cost Data," preliminary draft, 1977; Ron Knecht, Robert Logan, Seymour Goldstein, David Morse, and Ezra Amir, "Comparative Cost Analysis," Supporting Document No. 33 for A. B. 1852, February, 1978; and, same authors, "Comparative Cost Analysis Revised," Supporting Document 9, spring, 1978; Knecht, the "Fixed Charge Rate Model," cited above; and 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.

3. By Ebasco, as quoted by Knecht, in "Testimony", Ex. 7-2.

4. For example, Lewis J. Perl, "Estimated Costs of Coal and Nuclear Power Generation," National Economics Research Associates, December 12, 1978; "Comparative Cost Analysis," op. cit.; Rossin and Rieck, op.cit.; C. L. Rudasill, "Coal and Nuclear Generating Costs," Electric Power Research Institute, April, 1977.

5. Charles Komanoff, "A comparison of Nuclear and Coal Costs," Testimony, New Jersey Board of Public Utilities, October 9, 1978. In the equation

$$C_N = \$98.4 * N^{.827} * MW^{-.155} * AE^{-.134} * 1.23^{Tower} * .86^{Dupe}$$

assume the plant is the one hundredth built (N = 100), capacity is 1,000 MW, it is the architect-engineer's twenty-fifth plant (AE = 25), that it has a cooling tower (Tower = 1), and is a duplicate (Dupe = 1). The result is C_N = \$823.66 in 1976 dollars. Inflation at 14% per year to 1978 would give \$1,070 per kWe.

The Komanoff analysis is based upon data in William E. Mooz, "Cost Analysis of Light Water Reactor Power Plants," Rand Corporation, June, 1978. Neither Komanoff nor Mooz appear to be clearly explicit about the treatment of AFUDC in their data. I assume both mean to report actual investment expenditures, excluding AFUDC.

6. "Cost Analysis Revised," Appendix E, Table 3.

7. For accounting purposes, AFUDC is separted into an income-type item for equity and an expense-type item which reduces interest expenses. Each of the two components increase net income, and both become part of the rate base. The 8% AFUDC rate, then, is the composite of the two components and gives the addition to future rate base as well as the addition to net income during the construction period.

8. Wilfrid Comtois, "Power Plant Construction Schedules, Escalation, and Interest During Construction," presented at the American Power Conference, April 21, 1976, p. 5.

9. The 13% rate of return on stockholder equity which was used in Section 1 is rounded off from 12.65%.

10. "Baseline Cost Data," op. cit.

11. For the GNP inflation index, first quarter of 1979. Survey of Current Business, April, 1979, p. 17.

12. Personal communication.

13. See Komanoff, op. cit., Section 3 in that analysis.

14. These assumptions are taken from "Baseline Cost Data" and Knecht's "Review".

SECTION 3. PRICE DETERMINATION AND REGULATION

It may be expected that the divergence in cost methodologies discussed in Section 1 interacts with the complex model described in Section 2 above (and in Section 5, below, on decommissioing) to create a major problem with respect to price determination. Which method is to be utilized to measure nuclear power costs?

The difficulty is compounded by the financial inseparability of decisions which we wish to separte for analysis. For example: suppose (in Section 5) we hypothesize a decommisssioning fund which is liable to taxation. The resulting decommissioning allowance includes such a tax provision. But, in its early years, total tax liability may still be negative because of accelerated depreciation. Consequently, the allowance for taxation on contributions to the decommissioning fund turns out to be a tax-exempt contribution.

A second example: suppose a regulatory commission successfully manages flow-through rate-making. When accelerated depreciation is exhausted, taxes are allowed in rate setting. But, if other new construction is taking place simultaneously, deductions and credits can be so great as to shelter income from the plant which was itself supposed to be liable for taxation.

These problems are addressed to some extent in succeeding sections, but this introduction is sufficient to point out the problem.

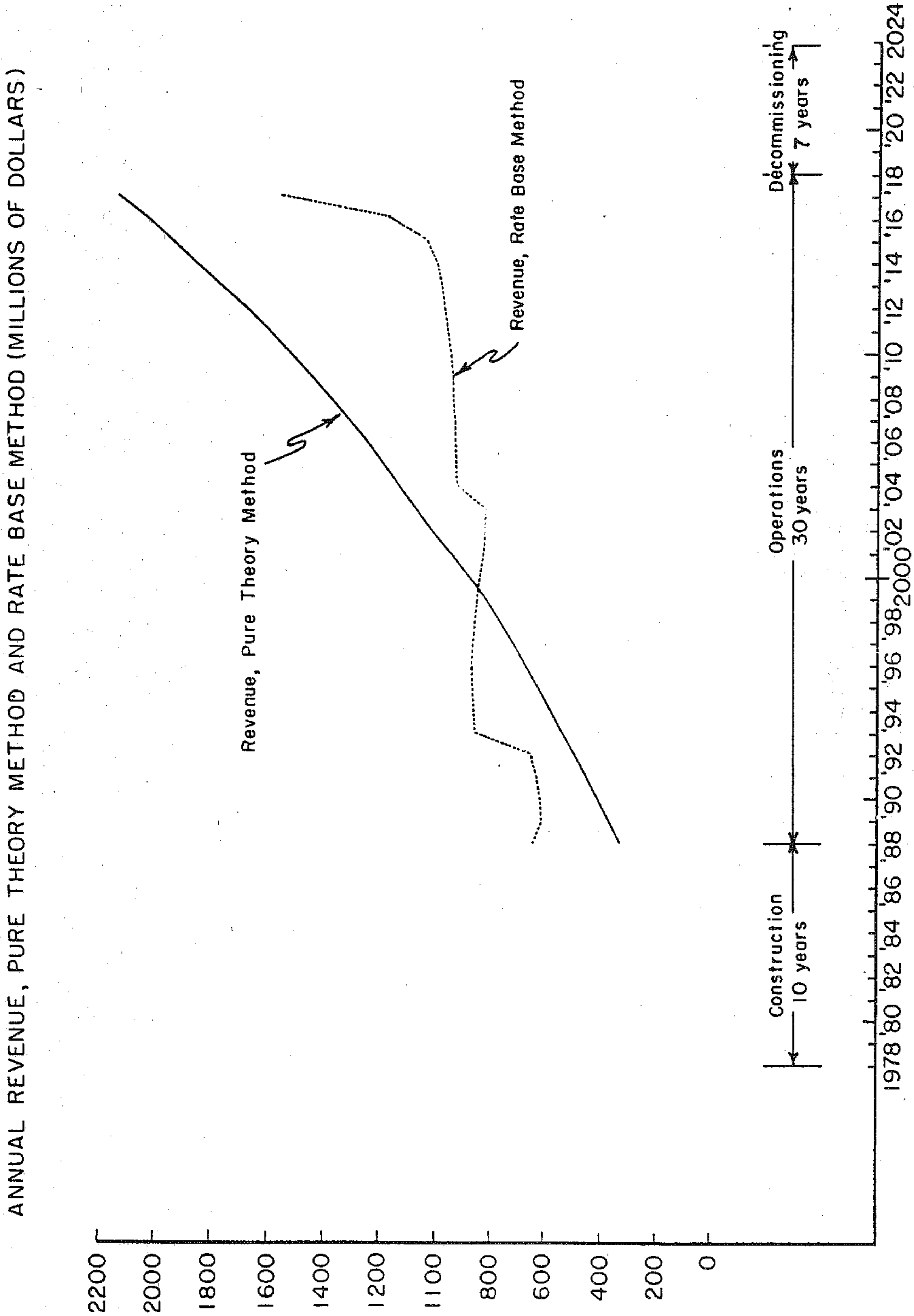
The specific problem of price determination is handled here by two approaches. First, the "pure theory" of Section 1B above is used to develop a computational algorithm. Second, actual regulatory methods are utilized to develop a second algorithm, and this is then compared to the first approach.

Eqs. (5) and (6) provide the computational basis for the theoretical calculation of appropriate prices. It will be recalled that the basic characteristics of this approach are (1) a return to stockholders' equity which is exactly equal to that allowed, and (2) a constant real price of electricity which increases at the same rate as general inflation.

Actual equity investment in plant totals $1.255 billion over the 10-year construction period. Equity investment in fuel inventory in the three-year period totals $145.9 million. At the assumed 12.65% equity return, these investments should grow to $149.4 billion by the end of 2024. This gives the objective for the pure theory method: the accumulated value of after-tax profit must reach $149.4 billion, and for this one must define a price path where price is constant in real terms, requiring nominal price to grow at 7% per year.

Such a price path appears in Figure 1. It begins at 6.9 ¢/kWh in 1988 and grows (at 7% annually) to 48.8 ¢/kWh in 2017. It is exactly sufficient to pay all debts and expenses, and provide a stream of after-

Figure 1.


ANNUAL REVENUE, PURE THEORY METHOD AND RATE BASE METHOD (MILLIONS OF DOLLARS)
Revenue, Rate Base Method
Revenue, Pure Theory Method
Construction
10 years
Operations
30 years
Decommissioning
7 years
1978 '80 '82 '84 '86 '88 '90 '92 '94 '96 '98 2000 '02 '04 '06 '08 '10 '12 '14 '16 '18 '20 '22 2024
2200
2000
1800
1600
1400
1200
1100
800
600
400
200
0

tax profits which grows to \$149.4 billion by the end of 2024. Included within the expenses is a decommissioning fund which accumulates \$724.6 million to pay decommmissioning costs which are incurred in the years 2018-2024. (This latter amount is explained in Section 5. Essentially, it is \$83 million in 1988 dollars, inflated at 7% per year.)

The second method of price determination is traditional rate of return on rate base, where benefits are flowed through to customers. It is based upon Eqs. (7)-(12). Table 8 shows the rate base components and annual depreciation expense in each component for the hypothetical plant. By reference to Eqs. (7)-(12), the printout Appendix, and Table 8, the reader may calculate necessary revenue requirements. The investment tax credit for rates is taken in the five years 1988-1993.

The result also appears in Figure 1. Price is 13.1 ¢/kWh in 1988; it declines to 11.7¢/kWh in 1992, and eventually reaches 36.0 ¢/kWh in 2017.

It is of interest to note that this regulatory (rate-base) approach causes a slight excess return: the profit account stands at \$178.3 billion at the end of 2024. This is equivalent to a 13.5% rate of return on equity after the construction period. (Recall the goal is 12.65% return on equity.) This is apparently because of the kind of problem noted in the beginning of this Section. The problem is so complex that an attempted analytical solution (the rate base method) may always allow higher prices and profit than an iterative solution which reaches the defined profit account goal (the pure theory method).

Note also the different time paths. The theoretical method for defining the real, constant dollar price gives a nominal price which rises at the general rate of inflation, 7% per year. Consequently, revenue shows the same smooth growth except for minor discontinuities caused by changes in capacity utilization.

However, the rate base method shows several discontinuities within a nearly uniform revenue curve. First, the uniformity in most of the period arises from the near-equivalence of two factors which are moving in opposite directions. Fuel and operating costs experience growing inflation. However, this is offset for much of the period by declining capital payments: rate base declines over the period.

Second, for the rate base method, revenue requiements increase after the five year period of investment tax credit benefit capture[1/], and again increase after 2003, with the exhaustion of depreciation deductions for Federal tax purposes. The last few years show major growth in revenue: fuel cost inflation and amortization of the last two batches (which are used for one and two years each) cause major increases in revenue requirements.

Notes and References for Section 3.

1. The value of the investment tax credit is compounded and amortized; see Section 4A.

Table 8. Rate Base Components of the Hypothetical Nuclear Power Plant original values in 1988 (million dollars)

	First year's rate base	Annual depreciation, 1988 - 2017
Plant investment	$ 3,112.0	$ 103.7
Fuel AFUDC	39.4	1.3
Decommissioning	724.6	24.2
Total rate base	$ 3,876.0	$ 129.2

Note: The rate base values here are identical to those assumed relevant for income and balance sheet statements. See printout Appendix B2, pp. 2, 4, 7, and 10, and later sections in text.

SECTION 4. TAXATION

Utility operations are subject to a variety of tax forms which apply to income earned from nuclear power generation.

This study addresses only the Federal and State income tax provisions applicable to utility profit. Property taxes are represented but not analyzed (see Section 4B, below).

In general, California corporate income taxation is similar to Federal policy. The major differences are the rates, and the guidelines for arbitrary tax lives.

In the following discussion the focus continues to be upon the manner in which tax provisions affect nuclear power costs. Relevant provisions are summarized. However, the reader is cautioned that this summary is not prepared by a tax accountant or attorney, but rather by an economist concerned with problems of resource use and pricing. Hence this summary is not exhaustive and may err in particulars. The description of the tax provisions themselves, then, should be seen as introductory, and perhaps a precursor to an investigation which will be of sufficient scale to address the complexity of the issues involved.

A utility will keep at least six sets of books or accounts on these items, and the entries for the same physical item or actual expense or income will appear differently in different sets of books or accounts. Simply put, net profit for stockholders, cash flow for management, rate base for Public Utilities Commission, property tax assessment, Federal depreciation and tax liability, and California depreciation and tax liability each require different accounts for the same actions.

4A. Federal Taxation

In this study attention has been given to those aspects of Federal income taxation pertaining to the exclusion of AFUDC income, interest deductions, State tax deductions, the investment tax credit, accelerated depreciation, tax lives, decommissioning expenses and funds, the repair allowance, non-taxable dividend payments, the conflict of interest in the stock ownership contributions of the investment tax credit, and the rate base capitalization of tax-deductible expenses.

Decommissioning finance and taxation are discussed separately in Section 5. The last four provisions are discussed here, below, but are not included within the model.

The other items have been explicitly included, both here and in the model.

AFUDC income

As noted previously, 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[1/].

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 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.

In the model used here, the 8% AFUDC rate is applied plant expenditures and to nuclear fuel inventory acquired during the three-year period preceding operations. It is applied to mid-year values and compounded. By the end of 1987, AFUDC has added $601.6 million to the plant rate base and $39.4 million to the fuel rate base[2/]. 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 forms of capital contribution -- common and preferred stock -- 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.

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

In this analysis, interest payments are planned to maximize tax deductions. Interest expense is paid each year during the construction period on plant and fuel inventory. During the period of plant operations, bond payments amortize debt with more than 90% of the payment going to interest in the early years[3/].

investment tax credit

The investment tax credit is a direct reduction in tax liability. At the mamimum rate, it is equal to 11 1/2% of qualified investment. Qualified investment is essentially construction cost exlcuding land and structures. AFUDC is not included. Qualified investment is thus approximately 95% of construction cost[4/]. The maximum effective rate, then, is 10.925% of actual construction cost.

This is a significant tax subsidy, its value being $349 million at the beginning of plant operations. With flow-through accounting and amortization of the credit in five years, customer costs are reduced by \$94.7 million each year in the period 1988-92[5].

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: here, from 3 1/3% to 6 2/3%. This percent is applied to the undepreciated basis at the beginning of each year, and the result is current depreciation expense 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 nomal 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[6].

In the model, the nuclear facility is depreciated at the maximum possible rate for Federal tax purposes. Since AFUDC is excluded from the depreciable basis, the 1988 value of the plant is \$2.510 billion for Federal tax purposes. This amount is the sum of actual construction expenditures. Depreciation expense is \$313.8 million in 1988, declines to \$123.2 million in 1995, and then switches over to the straight line method for the remaining eight years at \$107.8 million per year. The plant is wholly depreciated by 2003, and no further depreciation expense deductions can be applied to taxable income for the Federal corporate income tax. (See Table 9, below[7].)

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[8]. California utilities frequently select the percentage allowance because it exceeds actual expense.

The repair allowance rate for a nuclear power plant is 3% of cost, giving an allowance of $75.3 million in 1988.

In the model, repairs are included in the annual operations, maintenance, administration, and insurance cost estimate. This begins at $62.3 million in 1988 and stands at $223.3 million in 2017[9/]. Therefore, within the model, actual OM repair expenses are deducted, and no use is made of the repair allowance percentage.

non-taxable dividends

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

Suppose a company normally has positive and significant net income and net cash receipts: it then is in a position to make dividend payments and will normally elect 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 100 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.

No attempt has been made to represent this tax provision in the model. However, it can be noted that this provision increases the value fo tax subsidies pertaining to new construction by creating deductions which can be passed along to shareholders. I do not know how this affects California utilities. 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 $274 million[10/]. Of this amount, $35.7 million is contributed to the stock ownership plan[11/]. 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 disporportionate 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[12/].

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

capitalization of expenses

The Internal Revenue Code and regulatory commissions often differ in definitions of capital and current expense. No attempt has been made to consider this relationship within the model utilized here.

4B. California Taxation

The California tax rate on corporate income follows the Federal tax in most important respects. There are three significant differences. The most important, of course, is the rate applied to taxable income, being 46% for the Federal tax and 9% for the California tax.

Second, depreciation in California must be based upon median IRS tax lives rather than the minimum. For a nuclear plant, this is a 20-year tax life, rather than the 16-year life permitted in Federal tax depreciation.

Third, the California tax is a deduction with respect to calculating the Federal tax.

California property tax is apparently restricted to 1% of depreciated value, with an inflation adjustment restricted to 2% per year[13/].
Given the above observation on capitalization and expenses for Federal tax purposes, it would be logical for utilities to report the maximum possible amount for property tax liability. Since AFUDC is also excluded from the property tax basis, I would expect that the first year's property tax basis is 60.5% of the rate base basis. However, this possibility is not represented in the model, and property tax basis in 1988 is assumed (in the model) to be equal to the Federal and State income tax basis. No attempt has been made to represent property tax liability during construction.

The differences in valuation of the same investment are shown in Table 9. It may be observed that revenue-earning rate base valuation allows the least depreciation, while the account with the greatest potential tax liability -- the Federal income tax -- permits the greatest depreciation in early years.

Generally, a company will report its plant assets in a manner similar to its rate base valuation.

It should be recalled that Table 9 shows only the plant investment component of rate base; the total rate base is given in Section 3, Table 8.

4C. The Magnitude and Timing of Tax Subsidies

It was noted in Section 3 that a closely regulated utility would, by the pure theory method of real price determination, have a negative present value for the negative and positive tax liabilities associated with a new nuclear facility.

The rate base method of rate setting is less exact, and allows an overall rate of return on equity after the construction period of 13.5% rather than the intended 12.65%. There is small positive tax liability.

It is of considerable interest to determine what the after-tax cost of nuclear power would be if there were no tax subsidies. Assuming no tax subsidies, and recalling the discussion in the preceding Subsections 4A and 4B: California unsubsidized deductions might be simply straight line depreciation in plant and fuel, property tax, operating expense, and decommissioning cost when incurred. Gross income in each case would be revenue less fuel cost.

Federal deductions would now equal California deductions increased by the California tax.

The Federal tax would not be reduced by the investment tax credit.

Table 10 summarizes these points.

When the conventional case is simulated by the thoretical method to determine constant cost, the result is a 1988 price of 6.86 ¢/kWh. (Recall that 6.86 ¢/kWh, inflated at 7% per year, will give an exact return to equity of 12.65% while paying all future costs, taxes, and expenses required.)

However, when the no-subsidy case is simulated, the result is a 1988 price of 10.65 ¢/kWh. In other words, the tax subsidies discussed here are equivalent to 3.79 ¢/kWh, or approximately $206 million per year. Table 11 summarizes this situation. (And recall: several subsidies are not represented in the model.)

Fully 35% of the conventional cost of nuclear power is apparently paid in tax subsidies. With the approximate annual subsidy of $200

Table 9. Differences in Depreciation Reporting: Rate Base Valuation, Federal and California Income Tax Basis, and Property Tax Liability

Hypothetical Nuclear Plant, Five-Year Intervals (million dollars)

	Rate Base		Federal Tax		California Tax		Property Tax	
Year	basis	current depreciation	basis	current depreciation	basis	current depreciation	basis	current depreciation
1988	3,112.0	103.7	2,510.4	313.8	2,510.4	251.0	2,510.4	35.1
1993	2,593.4	103.7	1,287.6	161.0	1,482.4	148.2	2,309.7	45.3
1998	2,074.7	103.7	646.9	107.8	875.3	87.5	2,040.1	60.0
2003	1,556.0	103.7	107.8	107.8	437.7	87.5	1,689.3	81.1
2008	1,037.3	103.7	0	0	0	0	1,243.4	101.9
2013	518.7	103.7	0	0	0	0	686.4	126.3
2018	0	0	0	0	0	0	0	0

Source: Printout, Appendix C, p.2. Actual values used in analysis. Does not include expensing of capital items as discussed in the text.

Table 10. Deductions and Credits in the Conventional Case and Without Subsidies

Item	Tax Treatment: Conventional case	Tax Treatment: No tax subsidies
1. California tax		
A. Depreciation in plant	Accelerated depreciation, 20 year tax life	Normal depreciation, 30 year tax life
B. Interest payments	Deductible	No deduction
2. Federal tax		
A. Depreciation in plant	Accelerated depreciation, 18 year tax life	Normal depreciation, 30 year tax life
B. Interest payments	Deductible	No deduction
C. Investment tax credit	Allowed as costs incurred	No credit

In each case, California and Federal tax deductions are allowed for property taxes, operating costs, decommissioning expenses as incurred, amortization of fuel acquisition cost, and deduction of current waste fuel transportation and disposal cost. The California tax is a Federal deduction in each case.

Depreciation deductions in plant, fuel, and decommissioning rate base are not allowed.

Table 11. Nuclear Economics and Taxation

1,000MWe Pressurized Water Reactor

62% average capacity utilization

5.44 billion kWh/year

	Annual Cost 1988 dollars (in millions)	Cost (¢/kWh)	Cost per Unit 1988
Capital cost	417	7.67	$3,112/kW
Average property tax	13	0.24	
Operations, maintenance, administration, and insurance	62	1.14	$62 million/year
Fuel			
U_3O_8 ore	46	0.84	$100/lb
Conversion, UF_6	1	.02	7/kg U
Enrichment	22	.41	197/SWU
Fuel fabrication	5	.10	192/kg U
Transportation of fuel	1	.01	29/kg U
Transportation of waste	1	.01	29/kg U
Waste disposal	7	.13	250/kg U
	83	1.52	
Decommissioning	4	0.08	$83 million
- Tax subsidy	-206	-3.79	
Total after-tax cost to utility	373	6.86	
Total cost to economy	579	10.65	

million in 1988 dollars, 100 nuclear power plants of an average size of 1,000 MWe would require an annual subsidy of around $20 billion.

This must be termed one of the most important results of this analysis, and is probably the explanation for the continuing absence of current income tax liability for electirc utilities with large construction programs. California electric utilities report negative current income tax payments seven times in the last four years[14/].

The timing of tax subsidies, liabilities, and utility profit creates additional incentives for the construction of nuclear power plants. The following Figure 2 shows these accounts over the full 47-year period for a representative plant.

After-tax profit is positive throughout the construction period. This occurs for two reasons. First, the tax subsidies arising from the construction of a plant lower the utility's tax liability on income from other facilities. Second, the AFUDC allowance is a non-taxable component of net income. As a result, the hypothetical plant has accumulated a net profit of approximately $825 million by the end of the construction period and before actual generation begins. About $600 million of this arises from tax subsidies.

After-tax profit generally declines over the operating period. The cause, of course, is that revenue is based upon rate base, and rate base declines over the operating period.

The peculiar positive profit in the first year of decommissioning arises from tax and net income accounting differences in the treatment of waste fuel disposal. For net income corporate accounting, waste fuel cost from the last fuel batches has been amortized during the last years of operation. Consequently, for net income purposes, there is no waste fuel expense after operations cease. However, for tax purposes, the waste fuel expense is deductible only as incurred. In the first year of decommissioning, the tax reduction arising from the waste fuel expense deduction is sufficient to give a positive effect on after-tax net income. (Recall, again, that for net income accounting, this waste fuel expense had been previously charged to earlier years' operations.)

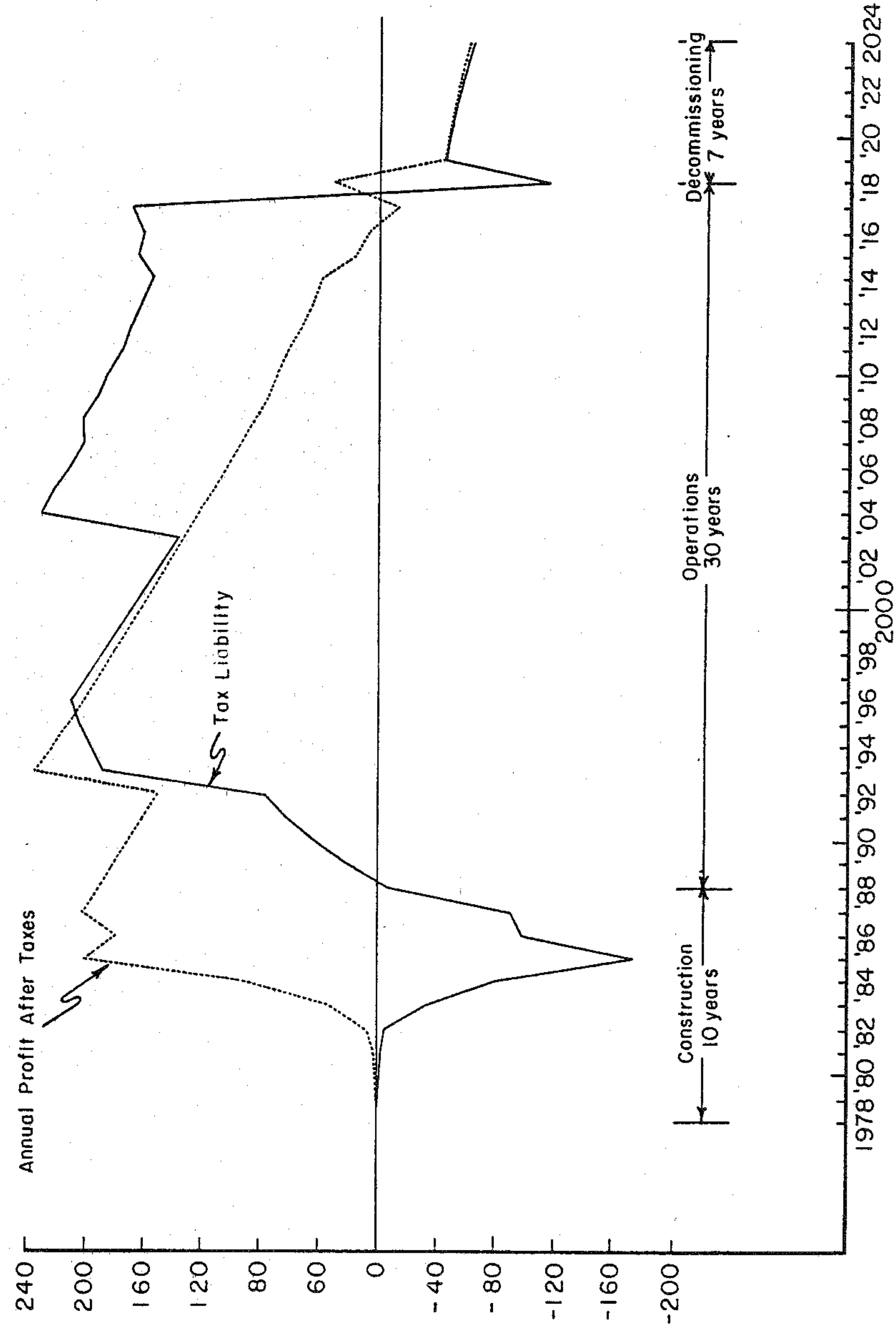
Tax liability follows an entirely different path. It is negative in the construction period, low in the first years of operation because of accelerated depreciation, and highest during the latter half of the operating period. The high positive tax in this latter period arises because, as noted above, accelerated depreciation has been wholly exhausted by depreciation deductions in 16 years for Federal taxation and in 20 years for California taxation. In this latter period, tax liability is approximately three and a half times greater than the profit level.

Figure 2 shows these contrasting time paths.

The net result is a disturbing pattern whereby tax incentives encourage premature construction of new plants and simultaneously encourage premature retirement of existing plants.

Figure 2.

ANNUAL TAX LIABILITY AND AFTER-TAX PROFIT, RATE BASE METHOD (MILLIONS OF DOLLARS)



There is a growing belief that tax subsidies are of such importance that the Federal budget should include them as explicit items[16/]. If such becomes the case, it is apparent that nuclear power would be shown to be a major beneficiary of such tax expenditures.

This study does not attempt to compare energy technologies or capital and labor-intensive activities according to the relative contribution which tax subsidies make to market prices, or to higher tax burdens on other public revenue sources. My opinion is that the utility industry is the most capital-intensive sector in the economy[17/], and that nuclear power is the most capital-intensive kind of generating technology. Consequently, it would be logical to expect that nuclear power receives tax subsidies which exceed in magnitude those received by any other kind of technology.

Notes and References for Section 4.

1. "Total income" here means total income before interest charges.

2. See printout, Appendix B2, pp. 1 and 8.

3. Ibid., pp. 1, 2, and 8.

4. Personal communications, U.S. Treasury Department, state regulatory staff, and utility personnel.

5. This is the rate base method; the credit is accumulated for 10 years at the overall rate of return (11.75%), and then amortized in five years. See printout, p. 1.

6. U.S. Internal Revenue Service, "Tax Information of Depreciation," Publication 534, 1979, p. 35.

7. Also see printout, p. 2.

8. See Michael Galvin, "Report on the Reasonableness of the Income Tax Allowance for Pacific Gas and Electric Company," California Public Utilities Commission, February 11, 1977, pp. 2-4.

9. See Section 2C, above.

10. See printout, p. 1.

11. Qualifying expenditures, recall, are 95% of total. $2.510 billion * .95 * .015 = $35.7 million.

12. Personal communications.

13. Commerce Clearinghouse, Guidebook to California Taxes, 1979, pp. 421-2.

14. In the four years 1975-78, the Pacific Gas and Electric Company paid positive amounts in 1977 and 1978, the San Diego Gas and Electric Company paid a positive amount in 1976, and Southern California Edison made positive payments in 1975 and 1976. In other words, in 7 of 12 instances, no payment was made or refunds from earlier years were received. Sources for this information are the companies' annual reports.

15. In this calculation, after-tax profit and negative (or positive) tax liability are valued at the after-tax rate of return of 12.65%. The $825 and $600 million figures are accumulated, compounded values at the end of the construction period.

16. See Seymour Fiekowsky, "Accounting for Tax Subsidies," U.S. Treasury Department, Office of Tax Analysis Paper 27, May, 1979.

17. A nuclear power plant with a cost of $3 billion and 200 permanent operating employees will have $15 million investment per employee. On an average basis for 1978, the three California utilities had $326,000 in total assets per employee. The comparable statistic for the country's 500 largest industrial corporations is $57,000 per employee.

Sources: California utility Annual Reports; Fortune, May 9, 1975, p. 269.

SECTION 5. DECOMMISSIONING

5A. State Policies

The U.S. Nuclear Regulatory Commission (NRC) has continued Atomic Energy Commission regulations which

> ...require applicants for power reactor operating licenses to furnish the Commission with sufficient information to demonstrate that they can obtain the funds needed to meet both operating costs as well as the estimated costs of permanently shutting down the facility and maintaining it in a safe condition.[1/]

However, in July, 1977, the Public Interest Research Group petitioned the Commission to require utilities to establish escrow bonds to cover costs of future decommissioning[2/].

In response to this petition, the NRC surveyed each state's regulatory authority to determine (1) whether the agency believed that decommissioning costs should be included in the utility rate base, and (2) the agency's views on the petition. The responses are summarized in Table 12, according to the status of nuclear power in each state[3/]. Thirty-eight states and Puerto Rico had licensed, ordered, or planned reactors as of September 30, 1978. Twenty-one of these thirty-nine did not reply to the survey. Nineteen did reply, including West Virginia which has no present or planned nuclear capacity.

In total, the responses can be divided into two groups. Ten states indicated a preference for the "negative salvage method", in which future costs are included within the rate base at the beginning of plant operations. Ten states indicated they had no policy or had not reached a decision. In this latter group, two states (Arkansas and Pennsylvania) indicated they were giving the problem considerable attention at the time of the survey.

In other words, at the beginning of 1978, 29 of 39 states (including Puerto Rico for this purpose) with licensed, ordered, or planned nuclear capacity did not or could not indicate their policy with respect to decommissiong finance.

The reason underlying the negative salvage method is of interest. Michigan reported that

> This method has the advantage of providing an increasing cash flow to the utilities ... for the funding of current construction programs.[4/]

The New York Commission offered a similar observation, stating that the negative salvage method generated funds based upon a decommissioning allowance in the rate base, and these funds may be "invested in the utility's own assets", which are presumably new construction programs[5/].

Table 12. State Responses to NRC Decommissioning Survey and Nuclear Power Capacity

	Nuclear Power Capacity, 9/30/78				Response to decommissioning survey, and status of plants, 1/1/78		
	Licensed		Ordered or planned 3/		No response	Apparently negative salvage method	No apparent method or decision
	# plants	MWe	# plants	MWe			
Alabama	4	4024	3	3299		x	
Arizona	0	0	5	8350	x		
Arkansas 1/	2	1762	0	0			x
California	3	1418	7	7970		x	
Colorado	1	330	0	0	x		
Connecticut	3	2065	1	1159		x	
Delaware	0	0	1	1200	x		
Florida	3	3013	1	842		x	
Georgia	2	1581	2	2200			x
Illinois	7	5446	10	13214	x		
Indiana	0	0	3	2920			x
Iowa	1	538	1	1270		x	
Kansas	0	0	1	1150	x		
Louisiana	0	0	3	3033	x		
Maine	1	790	0	0			x
Maryland	2	1690	1	1146	x		
Massachusetts	2	830	3	3480	x		
Michigan	4	5446	5	4833		x	
Minnesota	3	1605	0	0		x	
Missouri	0	0	2	2300	x		
Mississippi	0	0	4	5070	x		
Nebraska	2	1235	0	0	x		
New Hampshire	0	0	2	2388	x		
New Jersey	2	1740	8	8919	x		
New York	6	3285	10	11754		x	
North Carolina	2	1642	11	12160		x	
Ohio	1	906	7	7552			x
Oklahoma	0	0	2	2300	x		
Oregon	1	1030	2	2520	x		
Pennsylvania 1/	6	4797	7	9536			x
Rhode Island	0	0	2	2388	x		
South Carolina	4	3361	6	7030	x		
Tennessee 2/	0	0	11	1220		x	
Texas	0	0	5	6013	x		
Vermont	1	514	0	0	x		
Virginia	3	2551	5	5021	x		
Washington	1	850	7	8675			x
West Virginia	0	0	0	0			x
Wisconsin	4	1379	3	2950	x		
Puerto Rico	0	0	1	583			x

Sources: U.S. Nuclear Regulatory Commission: Annaul Report, 1978, and Docket PRM 50-22.

1. Planning major studies of decommissioning at time of survey.
2. The Tennessee Commission lacks jurisdiction over TVA facilities.
3. This table shows capacity data as of September 30, 1978, and does not reflect plants which are inoperable, nor orders or plans which have been cancelled.

The recognized difficulty with this approach, of course, is that a decommissioning fund invested in other utility construction is unavailable for decommissioning. Again, from the New York Commission:

> This vehicle accomplishes everything that a cash sinking fund or the posting of bonds in escrow would, except for the segregation of cash which the utility actually receives for decommissioning.[6/]

The material summarized here indicates a surprising lack of attention to the decommissioning problem as of early 1978, by the NRC as well as by the states. Substantial change in State policies has probably occurred since the survey, but this is not evident in recent NRC documents[7/].

In a Battelle report prepared for the NRC, the authors give no indication that the NRC survey was in response to the public interest group's petition[8/]. In fact, the text and footnotes suggest that public interest groups reacted to an NRC initiative.

The report notes:

> A recent NRC survey of public utility commissions found that the preferred approach was to treat the anticipated decommissioning costs as a negative salvage value for purposes of calculating depreciation on the nuclear power station.[9/]

and

> The funds are invested in new capital facilities in the utility system until needed for decommissioning....The total cost to the consumer is reduced since the utility does not have to pay servicing costs on borrowed money to build the new facilities.[10/]

5B. Cost Estimates

At this date the largest reactor to be fully decommissioned was the 58 MWt Elk River reactor in Minnesota; this reactor was used commercially for four years. No publication available to me gives capacity utilization or actual power generation over this period. If we suppose 33% net conversion efficiency and 62.5% capacity utilization[11/], the Elk River Reactor could be supposed to have had 48 MWe years of generating experience. A 1,000 MWe hypothetical facility with an average capacity utilization of 62% for 30 years will have had 18,600 MWe years of operation.

Given the rather dramatic differnce in scale, the Elk River Reactor would seem to be a poor guide to future decommissioning costs. There would seem to be little basis for understanding problems relating to long-lived radioactive isotopes of plutonium, nickel, and niobium, because the accumulation of such radioactive materials is directly related to length of operations.

In addition, the Elk River Reactor did not experience major problems comparable to the West Valley reprocessing facility or the Three Mile Island reactor.

Given the absence of relevant experience, cost estimates vary widely, and preferred modes of decommissioning show little similarity. I simply assume that, at present, full dismantlement over a seven year period is the preferred policy. Such an approach has been preferred by Smith et al at Battelle (on economic grounds) in their recent report, by the NRC (my interpretation of personal communications), and by California Energy Commission staff (again, a conclusion based upon personal communications). Similar views have been expressed by other technical analysts[12/].

As decommissioning cost estimates rise, however, we may expect that storage or entombment may become more popular in the future.

Table 13 shows some relevant estimates of dismantlement decommissioning costs.

The inexorable arithmetic of inflation at large exponential growth rates adds orders of magnitude to curent dollar estimates. The last row in Table 13 shows the effect of 14% inflation from 1988 through 2024. Decommissioning costs, valued in the future dollars of the years 21082024, range from $6 billion to $196 billion.

The bases for four sources of assumptions are shown in the first row of Table 13. The Battelle analysis of a 1175 MWe plant gives a cost of $42.1 million in 1978, Seven percent inflation gives $83 million in 1988.

CEC staff has asked that 10% of actual construction expenditure be used in this study as the decommissiong expense estimate. Ten percent of the $2.510 billion actual expenditures for the hypothetical plant is $251 million in 1988.

Skinner's study of the Elk River and Sodium Reactor Experiment decommissioning efforts led him to conclude that 24% of original cost was logical[13/]. For this analysis, the result is $602 million in 1988 dollars, $5.7 billion in future costs at 7% inflation, and $47 billion at 14% inflation.

Discussion with CEC staff and others raises the possibility that the Three Mile Island plant is so heavily contaminated that dismantlement may exceed original cost. The concrete inner walls are said to be coated with radioactive materials. Radioactive levels at the entrance way but outside containment are significant, and entry is not presently possible.

At present, the only future home for the Three Mile Island debris would seem to be New Mexico or Washington state.

Needless to say, the location of this degree of contamination on an island in the Susquehanna River -- up river from Baltimore and Washington -- impart a certain urgency to the problem.

Decommissioning cost at Three Mile Island had been estimated to be $95 million in 1977[14/].

Decommissioning cost at original cost is the fourth column in Table 13.

Table 13. Dismantlement Decommissioning Cost Estimates

Source:	Battelle 1978	CEC Staff 1979	Skinner 1977	hypothetical: Three Mile Island
Basis	$42.1 million in 1978; 1175 MWe PWR	10% of investment cost	24% of investment cost	100% of investment cost
Assume $2.510 billion plant, 1988 dollars	$83 million	$251 million	$602 million	$2.510 billion
Future cost, 2018-2024:				
7% inflation	$725 million	$2.362 billion	$5.670 billion	$23.625 billion
14% inflation	$6.014 billion	$19.606 billion	$47.056 billion	$196.066 billion

Interpretation of Table 13 is as much a matter of philosophy as of economics or engineering. I may note that nuclear power construction costs have experienced three-fold increases from pre-construction estimates to completed cost[15/]. The Alaskan oil pipeline was originally expected to cost $900 million before approval; following completion, later estimates give a cost of $9 billion, a ten-fold increase[16/].

The impending economic collapse of the Concorde[17/], the Skylab and atomic airplane projects -- these are technological failures on a massive scale. These observations find specific support in a recent RAND Corportion analysis which concludes that significant underestimation of future costs is a general rule for new technologies[16/].

On the basis of this apparent systematic understatement of engineering cost estimates of complex technological systems, I conclude the Battelle study is inadequate. I would consider Skinner's position to be a better guide to the future for normally operated plants, and I would expect column 4 to be a reasonable guide for damaged reactors with serious contamination problems.

However, I shall consider the sensibilities of readers preferring convention, and I shall focus on columns 1 and 2 as the primary basis for studying financial mechanisms for decommissioning expense.

5C. Taxation and Finance: Results

Five financial approaches to the problem of decommissioning are discussed here. They are:

A. Decommissioning cost is paid when incurred. No special provisions are made for this expense.

B. A special fund is created. Utility contributions are constant in real terms, meaning they grow at the assumed inflation rate. The contributions to the fund would be exempt from State and Federal income taxation, and fund earnings would be exempt. The Department of the Treasury has not approved such proposals.

C. A special fund is created and, under present-day law, neither contributions nor interest would be exempt.

D. Expected future decommissioning cost is included in the rate base. From Table 13, the 10% decommissioning cost assumption leads to a future cost of $2.4 billion, and this is placed in the rate base. No special fund is created.

E. The discounted present value of expected future decommissioning is placed in the rate base. The future cost of $2.4 billion would have a present value of $107 million in 1988.

Obviously these five approaches do not exhaust all possible solutions. The model as presently structured includes policy options whereby either fund contributions or interest are tax exempt but not both; and a fund grows through contributions which are constant in real terms (B and C above), or constant in actual nominal value payments over the operating period.

The model employed here has a potential 7,128 differnt analyses without further development[18]. Each would give differing estimates of decommissioning finance and its impact on total costs.

In addition, several other methods have been proposed which are neither contained within the model nor analyzed here. Two such methods are (1) escrow funding with the full amount of future decommissioning placed with some second party, and (2) a rate base method whereby expected decommissioning cost is included in year k's rate base in year k dollars, and is each year revised according to cost escalation as experienced for year k.

Policies A-E above have been selected for discussion because they appear to embody the major dimensions of interest. Future work may consider expanding the scope of analysis.

Tables 14 and 15 show five cases where total electricity cost is determined by the rate base method (Table 14) and the theoretically correct method of real price determination (Table 15). (The reader may wish to turn briefly to Figure 1 in Section 3 to examine the shape of revenue curves over the life of the facility. Prices follow paths which are almost identical in form to the revenue curves.)

Parts 1 and 2 in Table 14 show results differentiated by the two low-cost assumptions taken from Table 13.

Table 14 suggests answers to several current issues in decommissioning. First, including the future sum of decommissioning costs in the rate base (policy D) gives an excessive return to investors. The desired rate of return is 12.7%, and policy D exceeds this.

Second, there is little variation in total price as a result of variations in finance. With decommissioning cost assumed to be 10% of original cost ($251 million), 1988 total cost is between 9.4 ¢/kWh and 10.0 ¢/kWh for policies A, B, C, and E. In 2003 or 2017 the variation is no greater.

Third, the two cost assumptions make little difference on future costs. For example, the taxable fund for the $2.4 billion decommissioning future requires a 13.3¢/kWh price in 2003 (case 1C), while the taxable fund for the $725 million decommissioning future requires a 12.8 ¢kWh price in 2003 (case 2C)[19].

Table 15 examines the decommissioning cost question with the theoretical method of constant real price determination. Two conclusions from Table 14 are repeated in Table 15: there is little variation in total electricity cost to customers from either variations in decommissioning finance or in cost assumptions.

Table 14. Total Electricity Price and Decommissioning Cost: the Rate Base Method

	Total Future Price 1988 (¢/kWh)	Total Future Price 2003 (¢/kWh)	Total Future Price 2017 (¢/kWh)	Stockholder Return 1988-2024 (%)	Annual Tax 1978-2024 ($ million)
1. Decommissioning cost at $251 million in 1988 dollars, 7% inflation to 2024					
A. Decommissioning cost is paid when incurred	9.4	12.6	34.8	11.6	-$11.2
B. Fund is tax exempt	9.5	12.8	35.3	12.5	- 11.2
C. Fund is not tax exempt	9.7	13.3	37.0	12.5	- 5.9
D. Decommissioning in rate base, future sum	21.3	19.0	38.6	14.6	+ 59.9
E. Decommissioning in rate base, present value	10.0	12.9	35.0	12.4	- 8.0
2. Decommissioning cost at $83 million in 1988 dollars, 7% inflation to 2024					
A. Decommissioning cost is paid when incurred	9.4	12.6	34.8	12.3	- 10.7
B. Fund is tax exempt	9.5	12.7	35.0	12.4	- 10.7
C. Fund is not tax exempt	9.5	12.8	35.5	12.4	- 9.0
D. Decommissioning in rate base, future sum	13.1	14.6	36.0	13.2	+ 11.2
E. Decommissioning in rate base, present value	9.6	12.7	34.9	12.4	- 9.7

Note: Total price includes capital, fuel, and operating cost as well as decommissioning cost. The intended rate of return for stockholders is 12.65%; this is rounded to 12.7% in the text.

Table 15. Total Electricity Price and Decommissioning Cost: the Theoretical Method of Real Price Determination

	Constant Real Price 1988 Dollars (¢/kWh)	Annual Tax 1978-2024 ($ million)
1. Decommissioning cost at $251 million in 1988 dollars, 7% inflation to 2024		
A. Decommissioning cost is paid when incurred	6.9	-$2.9
B. Fund is tax exempt	6.7	- 6.9
C. Fund is not tax exempt	6.8	- 2.9
D, E. Rate base methods not applicable	---	---
2. Decommissioning cost at $83 million in 1988 dollars, 7% inflation to 2024		
A. Decommissioning cost is paid when incurred	6.9	- 2.9
B. Fund is tax exempt	6.8	- 4.2
C. Fund is not tax exempt	6.9	- 2.9
D, E. Rate Base methods not applicable	---	---

Note: In this method of price determination, a future price for a year k beyond 1988 is always $(1 + inf)^k \times P_{qo}$ where inf is the inflation rate and P_{qo} is the real price in 1988 dollars. Stockholder return is always the intended 12.65% (i.e., 12.7% to two decimal places).

The explanation for the absence of significant variation in total power cost as a consequence of variation in funding assumptions lies in the relationship of total revenues to decommissioning fund revenues. Table 16 shows the major components of total revenue requirements for case 1C, Table 14; (this is the case with the $2.4 billion future decommissioning cost, a taxable decommissioning fund, and the rate base method of price determination). Decommissioning fund revenues approximate only 3% to 8% of total revenues.

The fund mechanism for this particular case appears in Table 17. Note that tax requirements grow to nearly equal total fund contrubutions by the last years of operations; this is because taxes must be paid on the fund's interest earnings as well as on the income paid into the fund.

Note also that the fund balance equals $1.054 billion at the beginning of 2018, considerably less than the expected cost of $2.4 billion. In the ensuing seven years, the fund receives $1.086 billion in captured tax benefits; Decommissioning costs are deductible and the tax reduction is placed in the fund. In addition, the fund earns $0.226 billion in interest in these seven years 2018-2024. The negative interest in 2024 represents the cost of borrowed money used until the tax benefit is available.

Table 16. Components of Total Revenue Requirements: Decommissioning Fund, Revenue Requirement for Plant Capital Recovery, Fuel, and Operating Cost; Rate Base Method of Price Determination (million dollars)

Year	Revenue Requirement for Decommissioning Fund (DEC REV)	Revenue Requirement for Plant Capital Recovery (ANNUAL REV REQMT)	Amortized Fuel Expense (AMFUEL)	Administrative, Insurance, Operations, and Maintenance Expense (O&M)	Total Revenue Requirement (REVENUE)
1978-87	0.000	0.000	0.000	0.000	0.000
1988	13.586	272.279	120.470	62.296	468.630
1989	14.537	292.618	83.675	65.099	455.929
1990	15.555	308.094	76.094	68.028	467.771
1991	16.644	319.307	82.056	71.089	489.096
1992	17.809	326.778	88.295	74.288	507.171
1993	19.055	523.695	95.014	77.631	715.396
1994	20.389	525.003	102.250	81.125	728.767
1995	21.817	523.783	110.043	84.775	740.417
1996	23.344	520.340	118.436	88.590	750.510
1997	24.978	502.330	127.477	92.576	747.361
1998	26.726	484.181	137.215	96.742	744.864
1999	28.597	465.037	147.705	101.096	742.434
2000	30.599	445.860	159.005	105.645	741.108
2001	32.741	426.650	171.178	110.399	740.967
2002	35.033	407.403	184.292	115.367	742.094
2003	37.485	388.119	198.421	120.558	744.583
2004	40.109	469.732	213.644	125.983	849.467
2005	42.916	450.371	230.045	131.652	854.985
2006	45.921	430.970	247.718	137.576	862.184
2007	49.135	411.527	266.760	143.767	871.189
2008	52.574	400.698	287.279	150.237	890.788
2009	56.255	381.167	309.390	156.997	903.810
2010	60.192	361.591	333.219	164.062	919.064
2011	64.406	341.968	358.898	171.445	936.716
2012	68.914	322.296	386.573	179.159	956.943
2013	73.738	302.574	416.400	187.222	979.933
2014	78.900	282.800	448.546	195.646	1005.893
2015	84.423	262.973	513.234	204.450	1065.080
2016	90.332	243.091	642.436	213.650	1189.510
2017	96.656	223.153	1078.805	223.264	1621.878
2018-24	0.000	0.000	0.000	0.000	0.000

Note: This is case 1C, Table 14. The abbreviated headings are those used in the printout in Appendix B. (Appendix B itself uses case 2C.) (See also Figures 1 and 2 which show revenue, profit, and tax liability for case 2D.)

Table 17. Taxable Decommissioning Fund with Future Decommissioning Cost Assumed to be $2.4 Billion

Year	Actual Decommissioning Expenditures (DEC EXP)	After-tax Contribution to Fund (ANN PMT)	Interest Earned (DF INT)	Fund Balance (FUND)	California Tax Deductions (CAL DED)	California Taxable Income (CAL TAX INC)	Assumed California Tax (CAL TAX)
1978-87	0.000	0.000	0.000	0.000	0.000	0.000	0.000
1988	0.000	6.676	0.000	0.000	0.000	13.586	1.223
1989	0.000	6.821	0.634	6.676	0.000	15.172	1.365
1990	0.000	6.961	1.343	14.132	0.000	16.897	1.521
1991	0.000	7.095	2.131	22.435	0.000	18.775	1.690
1992	0.000	7.222	3.008	31.661	0.000	20.817	1.873
1993	0.000	7.340	3.980	41.890	0.000	23.035	2.073
1994	0.000	7.448	5.055	53.210	0.000	25.444	2.290
1995	0.000	7.546	6.243	65.713	0.000	28.059	2.525
1996	0.000	7.630	7.553	79.502	0.000	30.896	2.781
1997	0.000	7.699	8.995	94.684	0.000	33.973	3.058
1998	0.000	7.752	10.581	111.378	0.000	37.307	3.358
1999	0.000	7.785	12.323	129.711	0.000	40.920	3.683
2000	0.000	7.798	14.233	149.819	0.000	44.832	4.035
2001	0.000	7.786	16.326	171.849	0.000	49.066	4.416
2002	0.000	7.747	18.616	195.961	0.000	53.649	4.828
2003	0.000	7.678	21.121	222.324	0.000	58.606	5.275
2004	0.000	7.576	23.857	251.122	0.000	63.965	5.757
2005	0.000	7.437	26.843	282.555	0.000	69.759	6.278
2006	0.000	7.257	30.099	316.834	0.000	76.020	6.842
2007	0.000	7.032	33.648	354.190	0.000	82.783	7.450
2008	0.000	6.756	37.513	394.869	0.000	90.087	8.108
2009	0.000	6.426	41.718	439.138	0.000	97.973	8.818
2010	0.000	6.035	46.292	487.281	0.000	106.484	9.584
2011	0.000	5.577	51.263	539.608	0.000	115.669	10.410
2012	0.000	5.046	56.662	596.447	0.000	125.577	11.302
2013	0.000	4.435	62.525	658.155	0.000	136.263	12.264
2014	0.000	3.736	68.886	725.115	0.000	147.786	13.301
2015	0.000	2.941	75.785	797.736	0.000	160.208	14.419
2016	0.000	2.041	83.264	876.462	0.000	173.596	15.624
2017	0.000	1.027	91.368	961.768	0.000	188.024	16.922
2018	272.995	101.101	74.211	1054.162	272.995	-198.784	-17.891
2019	292.104	116.463	63.116	956.480	292.104	-228.989	-20.609
2020	312.551	133.288	50.483	843.955	312.551	-262.068	-23.586
2021	334.430	151.694	36.171	715.174	334.430	-298.259	-26.843
2022	357.840	171.813	20.023	568.609	357.840	-337.817	-30.403
2023	382.889	193.784	1.873	402.606	382.889	-381.015	-34.291
2024	409.691	217.757	-18.460	215.374	409.691	-428.151	-38.534

Table 17. (continued)

Year	Federal Tax Deductions (FED DED)	Federal Taxable Income (FED TX INC)	Assumed Federal Tax (FED TAX)	Total Assumed Tax (TAX EFFECT)	Revenue Required for Decommissioning Fund (DEC REV)
1978-87	0.000	0.000	0.000	0.000	0.000
1988	1.223	12.364	5.687	6.910	13.586
1989	1.365	13.806	6.351	7.716	14.537
1990	1.521	15.377	7.073	8.594	15.555
1991	1.690	17.085	7.859	9.549	16.644
1992	1.873	18.943	8.714	10.587	17.809
1993	2.073	20.962	9.642	11.716	19.055
1994	2.290	23.154	10.651	12.941	20.389
1995	2.525	25.534	11.746	14.271	21.817
1996	2.781	28.116	12.933	15.714	23.344
1997	3.058	30.915	14.221	17.279	24.978
1998	3.358	33.950	15.617	18.974	26.726
1999	3.683	37.237	17.129	20.812	28.597
2000	4.035	40.797	18.767	22.801	30.599
2001	4.416	44.650	20.539	24.955	32.741
2002	4.828	48.820	22.457	27.286	35.033
2003	5.275	53.331	24.532	29.807	37.485
2004	5.757	58.209	26.776	32.533	40.109
2005	6.278	63.481	29.201	35.479	42.916
2006	6.842	69.178	31.822	38.664	45.921
2007	7.450	75.333	34.653	42.103	49.135
2008	8.108	81.979	37.710	45.818	52.574
2009	8.818	89.155	41.011	49.829	56.255
2010	9.584	96.901	44.574	54.158	60.192
2011	10.410	105.258	48.419	58.829	64.406
2012	11.302	114.275	52.566	63.868	68.914
2013	12.264	123.999	57.040	69.303	73.738
2014	13.301	134.485	61.863	75.164	78.900
2015	14.419	145.789	67.063	81.482	84.423
2016	15.624	157.973	72.667	88.291	90.332
2017	16.922	171.102	78.707	95.629	96.656
2018	255.104	-180.893	-83.211	-101.101	0.000
2019	271.495	-208.379	-95.855	-116.463	0.000
2020	288.965	-238.482	-109.702	-133.288	0.000
2021	307.586	-271.416	-124.851	-151.694	0.000
2022	327.436	-307.413	-141.410	-171.813	0.000
2023	348.597	-346.724	-159.493	-193.784	0.000
2024	371.157	-389.617	-179.224	-217.757	0.000

Note on Table 17.

Decommissioning expenditures equal 0.1 * $2,510 million * 1.07^{k-1} with k here being years since opeations began. After-tax contribution to the fund equals revenue less tax effect. Interest earned equals 9.5% of beginning-of-year fund balance. California deductions equal actual decommissioning cost in 2018-2024. California taxable income equals interest plus revenue less deductions. Assumed California tax is 9% of California taxable income.

Federal figures are calculated analogously, except deductions include California tax, and the rate is 46%. Total tax is the sum of Federal and California taxes.

Revenue is that amount which, when increased 7% per year during the operating period 1988-2017, will create a fund which will terminate at the beginning of 2019 with a final balance smaller than ± $5 million. It is found by iterative solution.

The abbreviated headings are those used in the printout, Appendix B.

The policies for decommissioning finance can also be examined for their effects on stockholders and on tax revenues. In Table 14, it is evident that the fund methods used in conjunction with rate base price determination will give an equity return very close to the intended 12.7% rate. (In Table 15, the pure theory method always finds a price solution by iteration so return is 12.7%, and of course the fund policies (1B, 1C, and 2B, 2C) have the required 12.7% return.)

The last columns in Tables 14 and 15 show the amortized tax liability which the facility imposes on the company's economic structure over a 47-year period of construction, operations, and decommissioning[20/]. Except for cases 1D and 2D, tax liability is always negative in every case in both tables. Since policy D has already been rejected, it is evident that the method of decommissioning finance has little effect on overall tax subsidies.

My conclusion here is to clearly favor the funding mechanism. It offers the greatest assurance of future fund availability, it has little effect on total electricity cost, and little effect on stockholder return or on the magnitude of tax subsidies.

I should add that I consider funding as discussed here to be synonymous with some form of guarantee. Possible types of funding guarantees include bonding, deposits, and escrow accounts.

It is of interest to compare this conclusion to those of Wood and Collins[21/]. Wood's analysis is institutional in the sense that it focuses upon the basic NRC requirements cited at the beginning of this section. Wood wishes to know how various financial mechanisms meet criteria for assurance, cost equity, unexpected changes, and complex jurisdictional responsibilities for decommissioning.

He concludes that funding is to be preferred, and that particular funding policies are not particularly important as long as one of these policies is actually used. He explicitly rejects methods without actual funds (e.g., policies A, D, and E in this analysis).

Preston Collins' perspective leads him to rather different conclusions. He favors eliminating tax liability on funds, basing the choice of mechanisms on minimum cost to the utility, and excluding the NRC and utility commissions from decision-making responsibilities in this area.

The major difference between the present study and those addressed solely to the decommissioning quetion is one of context. Wood, Collins, and others view decommissioning in isolation from other aspects of nuclear economics. This analysis imbeds decommissioning within the overall planning horizon of plant construction, operation, and decommissioning. The result, as already noted, is to place in perspective the decommissioning question. It has been shown that, with present conventional cost assumptions, choice of financial mechanism has little or no economic significance.

My work here is in considerable contrast to Wood's analysis. This approach is unrelentingly quantitative, and sets the decommissioning question in an overall framework of tax liability and subsidies, fuel and operating cost, and plant cost. Nevertheless, our conclusions are very similar.

However, a most important caveat is in order. The preceding discussion is based upon the low-cost entries in Table 13. With 14% inflation applied to the two high-cost estimates in Table 13, the real cost of electricity reaches 7.9 ¢/kWh (the 24% Skinner case) and 11.3 ¢/kWh (the 100 % Three Mile Island case). Tax subsidies remain operative, and the increased total cost is wholly attributable to higher decommissioning costs.

The conclusion to Section 5B above noted that low-cost assumptions would be used in deference to convention and credibility rather than because of the author's agreement. Yet the magnitude of cost differences noted directly above raises important new issues. If decommissioning costs should in fact be measured in tens or hundreds of billions of dollars, then financial mechanisms will be rather moot. An economic problem of this magnitude -- involving perhaps 75 to 100 power reactors -- would be clearly beyond the capabilities of utilities to manage. Two kinds of consequences are clear. One, obviously, is that decommissioning costs of very large magnitude mean, simply, the abandonment of nuclear power as a viable technology. Second, the technical and economic problems would, in the extreme, require emergency national mobilization.

It becomes evident that actual experience is of pressing urgency. Commissioner Varanini has recommended that the Humboldt Bay plant be dismantled to acquire immediate actual experience[22/]. My own conclusion, arising out of my investigation here, is to urge such a course with considerable urgency.

Notes and References for Section 5.

1. U.S. Nuclear Regulatory Commission, Plan for Reevaluation of NRC Policy on Decommissioning Nuclear Facilities, NUREG-0436, Revision 1, December, 1978, p. i.

2. Eleven other public interest groups have joined in sponsoring the petition.

3. The source for this information on state policies in U.S. Nuclear Regulatory Commission, Docket PRM 50-22.

4. Michigan Public Service Commission, letter to NRC, December 14, 1977.

5. New York Public Service Commission, letter to NRC, January 9, 1978.

6. Ibid.

7. U.S. Nuclear Regulatory Commission, "NRC Issues Response to Petition on Decommissioning of Nuclear Power Plants," June 22, 1979; Plan for Reevaluation of NRC Policy, op. cit.

8. R. I. Smith, G. J. Konzek, and W. E. Kennedy, Jr., Technology, Safety, and Costs of Decommissioning a Reference Pressurized Water Reactor Power Station, prepared for the U.S. Nuclear Regulatory Commission by the Battelle Pacific Northwest Laboratory, NUREG/CR-0130, vol. 1, June, 1978, p. 6-1.

9. Ibid.

10. Idem. p. 6-3

11. This reactor operated for 2.5 full power years in a four-year period, implying a 62.5% average capacity utilization. See Smith, p. 7-16.

12. John S. Ferguson, Middle West Service Company, "A Case for Funding Nuclear Plant Decommissioning Cost," Power Engineering, December, 1978, p. 53, and Joseph A. Sefcik, "Decommissioning Commercial Nuclear Reactors," Technology Review, June/July, 1979.

13. Peter N. Skinner, Professional Engineer, New York State Attorney General's Office, Testimony, New York Public Service Commission, Case 26974, "Comparative Economics," December 2, 1977.

14. W. A. Verrochi, Pennsylvania Electric Company, Statement, Pennsylvania Public Utilities Commission, May 20, 1977.

15. Ron Knecht, et al., "Comparative Cost Analysis (Revised), "California Energy Commission, spring, 1978.

16. Ed Merrow, A Review of Cost Estimation in New Technologies: Implications for Energy Process Plants, Rand Corporation, R-2481, July, 1979.

17. New York Times, August 11, 1979, p. 1.

18. The combinations in decommissioning total 44. Waste fuel cost is analyzed with a future cost of $250/kg vs. $2500. Fuel expense is treated in any of three accounting methods, and each of three accounting entities (the regulatory commission, the IRS, the company) may select any of the three methods.

There are three pricing methods of analysis: pure theory, rate base, and social cost. As a result, 44 * 2 * 3 * 3 = 7,128. Not included in this total are additional variations in plant, fuel, or decommissioning costs, general inflation, or specific changes in California or Federal tax policy.

19. Recall from Table 13 that $251 million at 7% inflation gives a future cost of $2.4 billion, while $83 million at the same inflation gives a future cost of $725 million.

20. It may recalled that Table 11 in Section 4 amortized tax liability over the 30-year operating period.

21. Robert S. Wood, U.S. Nuclear Regulatory Commission, "Assuring the Availability of Funds for Decommissioning Nuclear Facilities," July, 1979; Preston Collins, Gilbert Associates, "Financing and Accounting Alternatives for Decommissioning Nuclear Plants," September, 1978.

22. See correspondence, Commissioner Emilio E. Varanini III, to then-Secretary of Energy James Schlesingerand to then-Commissioner and President Robert Batinovich, California Public Utilities Commission, both letters November 17, 1977.

SECTION 6. SOCIAL COST AND SENSITIVITY ANALYSIS

The major results of the preceding sections are that (1) the present value of tax liability on revenue from a new nuclear plant is negative, and that (2) with present conventional assumptions of future decommissioning cost, a decommisssioning fund -- with or without tax liability -- has little additional effect on total power cost.

In this section the model is used to explore the consequences of variations in assumptions. Obviously, all 7,128 solutions for differing original assumptions have not been examined. If one variation in each of 35-40 original assumptions were to be examined, the possible number of solutions becomes very large. Rather than such a headlong plunge into random sensitivitiy analysis, I have selected eight cases which involve areas where I believe future costs may be considerably higher than those conventional assumptions employed elsewhere in this study.

The method of price determination in this section is always the real cost method, which, by iterative solution, always defines a stockholder's return exactly equal to 12.65% over the 47-year period. For the base case, a decommissioning fund is used, and its contributions and interest are liable to taxation. Decommissioning cost is 10% of original cost, and inflation in this is 7% per year (see Table 13). Current Federal and State income tax provisions are applied. As noted previously, this gives a real price in 1988 dollars of 6.82 ¢/kWh. Tax liability on an amortized, levelized basis is -$2.9 million per year over the 47-year period [1/]. These values are the first case in Table 18.

6A. Uranium Availability

In previous years the question of uranium availability has been of considerable interest. It was the subject of a separate report in this research project[2/]. The conclusion reached there was that a rapidly expanding nuclear power industry would require either the discovery of new domestic sources or significant use of imported uranium. Estimates of the potential for discovery differ widely.

The Three Mile Island accident has reduced growth in nuclear power capacity because licensure of new plants has been delayed. Declining electricity demand also has caused utilities to delay new construction. In addition, nuclear power cost on an after-tax basis (i.e., including tax subsidies) has lost much of its advantage over coal power. These factors interact to reduce demand for uranium. Nevertheless, it appears unlikely that present proven domestic reserves of uranium are sufficient to supply the nuclear capacity which is presently planned. The analysis here assumes 228 tons of U_3O_8 are required each year for a 1,000 MWe facility[3/].

In early 1978, the Department of Energy estimated proven U.S. reserves in the "forward cost" category of \$30/lb U_3O_8 to be 690,000 tons. Sullivan describes forward cost as being development cost.

Table 18. Sensitivity Analysis: Real Total Electricity Cost with Less Conservative Assumptions (1988 dollars)

Case Number	Description	Total Real Cost 1988 dollars (¢/kWh)	Annual Tax 1978-2024 ($ million)
1.	Conventional assumptions	6.82	-2.9
2.	Uranium ore costs $155/lb in 1989	7.37	-1.2
3.	Capital cost is $2,094/kWe, 1978 dollars	11.45	-12.0
4.	Fuel is expensed on a cash flow basis	8.01	+16.7
5.	Fuel is amortized on a cost of goods sold basis	6.71	-2.4
6.	Waste fuel disposal cost is $2500/kg in 1989	8.23	+3.2
7.	Future decommissioning inflation is 14%	7.32	-2.9
8.	No tax subsidies	10.61	+105.9
9.	Ultimate case a. No tax subsidies b. Uranium ore costs $155/lb in 1989 c. Capital cost is $2,094/kWe, 1978 dollars d. Waste fuel disposal cost is $2500/kg in 1989 e. Future decommissioning cost is 10% of original cost, with 14% inflation	21.68	+208.6

Note: Uranium ore cost and waste fuel disposal cost are 1989 prices in 1989 dollars. See Table 4 for specific inflation assumptions.

Market price will include this as well as exploration cost and profit. Sullivan reports market prices to be 50-100% higher than forward cost[4/]. Using the lower figure, a forward cost of $30/lb gives a market cost of $45/lb.

Notwithstanding the considerable uncertainty in this data, it is a rough approximation to note that, in 1978, there were believed to be 690,000 tons of uranium ore which would be produced and sold at a market price of $45/lb in 1978 dollars.

We can assume, then, that the 690,000 tons of proven reserves at $45/ton would supply 3,026 1,000 MWe years of operation.

If reactor capacity were to be limited to the 148.4 GWe (gigawatt electric) which were operating in early 1978, there would be sufficient presently proven domestic reserves until 2001. If more extensive development occurred, as in the plan held by the U.S. Department of Energy in 1978, capacity would be 389 GWe in 2000 and continue to grow. At this rate, the cited reserves would be exhausted in 1997[5/].

In terms of a higer price than that used in the study here, I shall use a 50% higher price (i.e., $155/lb in 1989, rather than $103.30) as representative of future price possibilities.

The result appears as case 2 in Table 18. Total cost rises by 5.5 mills to 7.37 ¢/kWh in 1988 dollars. A 50% increase in ore cost has raised total after-tax electricity cost by 8%.

6B. Capital Cost and Other Factors

The effect of changes in capital cost is greater. Higher capital costs also increase decommissioning costs and interest and AFUDC charges. In case 3, the original cost per kWe has been doubled from $1,047 to $2,094. The result: electricity cost is 11.45 ¢/kWh, and tax liability is made negative.

R. R. Bennett (from Ebasco) had attributed 83% of capital cost increases to changing regulatory requirements, this being for the period 1969-1977[6/]. I am certain that this will continue into the future.

Cases 4 and 5 examine the effect of fuel accounting on customer cost. Recall the conventional case attaches actual fuel acquisition and disposal cost to each fuel batch, and amortizes this cost as the fuel is used during the operating period. This has been shown earlier as the first column in Table 6, Section 2B[7/]. Now, for case 4, simply suppose that the utility and the Public Utilities Commission charge expenses as incurred -- the last column in Table 5. The result is higher customer costs; 8.01 ¢/kWh. Presumably the higher customer cost arises because fuel acquisition costs in the 1985-87 period reduce nominal profit in this case, requiring higher rates in the operating period.

Case 5 shows another accounting treatment of fuel cost. It is the IRS method, the cost of goods sold basis, column 3 in Table 6.

Since spent fuel transportation and disposal cost are not charged to expenses until actually incurred, nominal profit is increased. Consequently, slightly lower rates may be charged to give the same rate of return.

The next case in Table 18 addresses waste fuel disposal costs. In my opinion, the basic problems of technological optimism which were discussed in the context of decommissioning cost (Section 5B) are equally applicable to waste fuel disposal. My view is that a ten-fold increase in future cost is likely. In other words, the model has used a $250/kg charge in 1989[8/], but I think $2500/kg is equally likely.

In support of this higher figure, two points can be made. First, the MHB analysis (still an engineering study without actual experience) concluded that a $650 charge is a better reference estimate, and also gives a high estimate of $1542/kg[9/]. This latter figure involves a 1978 present value cost of $94 billion. Second, in the year and a half following the publication of the U.S. Department of Energy's Draft Nuclear Waste Management Report[10/], no progress is evident, and waste fuel continues to accumulate at operating reactors.

The possibility now exists that there will be no Federal solution to the waste problem, or, that by the time enough is known to make a decision, each State and utility will have had to deal with the mounting problem by developing its own policies on waste disposal.

The result of the $2500/kg U waste charge gives a total real cost of electricity of 8.23 ¢/kWh. A ten-fold increase, then, raises total cost 21%.

Case 7 examines additional variations in decommissioning assumptions. In case 7, inflation for decommissioning is now 14% rather than 7%, so future costs are $19.6 billion instead of $2.4 billion[11/]. The expensing method is utilized to reduce the impact of choice of financial method on real levelized cost. The result: 7.32 ¢/kWh cost.

Tax subsidies are eliminated in case 8, and the cost of electricity is similar to Table 11. Total generating cost is 10.61 ¢/kWh on a real cost basis in 1988 dollars.

The ultimate high-cost case with respect to total cost may assume that each assumption discussed here has, in the conventional analyses, been seriously deficient in realism. In addition, no tax subsidies are allowed.

The major elements in this high-cost case, in contrast to case 1, are as follows:
(1) No tax subsidies;
(2) Capital cost doubles to $2,094/kWe in 1978 dollars;
(3) Waste fuel disposal cost increases ten-fold to $2500/kg U in 1989;
(4) Future decommissioning cost is 10% of investment cost, inflation in this cost is 14% annually, and the future cost is $39 billion.

This case comes closest to being a subjective interpretation of social cost, and the total cost of electricity from the hypothetical plant is 21.68 ¢/kWh.

In a sense, this "ultimate" case represents a cascading of collapsing assumptions. The quantitative result is of such a magnitude that it would represent a qualitatively different environment for nuclear power. A cost of production of this magnitude would represent the inter-action of problems of increasing difficulty, and a recognition of the significance of tax subsidies. It would probably be associated with a discontinuation of nulcear power.

The conclusions and recommendations which I derive from this study are placed at the end of the Introduction and Summary, pages 4 to 5.

Notes and References for Section 6.

1. Recall that Table 11 shows tax subsidy rather than tax liability, and amortizes this over the 30-year operating period rather than a 47-year period.

2. Stephen J. Sullivan, "Uranium Availability," prepared for the California Energy Commission, October 31, 1978.

3. See Table 3 in Section 2B above; this 228 tons estimate, recall, is from the Cady/Hui study. Other estimates differ slightly. Sullivan assumes 210 tons; Knecht's Wisconsin analysis (op. cit., p. 4, Ex. 6) assumes 211 tons.

4. Sullivan, pp. 7-9.

5. These data are from U.S. Department of Energy, Report of Task Force for Review of Nuclear Waste Management, Draft, February, 1978, p. 108. The method used here is illustrated for the high growth case.

From 1977 to 1985, X (capacity in GW) is $49.9e^{.1167t}$. From 1985 thereafter, $X_k = 126.9e^{.0731k}$, and k is years from 1985. G_t (cumulative generation) is $427.6(e^{.1167t} - 1)$ from 1977 to 1985, and $G_k = 1{,}736.0(e^{.0731k} - 1)$ from 1985. Cumulative consumption of ore is 228 tons/GWe per year * G_k.

6. "Comparative Analysis (Revised)," p. 28.

7. Also, a small amount -- $1.4 million per year -- is collected from customers from the AFUDC allowance for pre-operations fuel acquisition. See column 2, Table 6.

8. See Table 4, Section 2B.

9. MHB Technical Associates, Spent Fuel Disposal Costs, prepared for the Natural Resources Defense Council, August 31, 1978.

10. Nuclear Waste Mangement, op. cit.

11. See Table 13, Section 5B.

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APPENDIX A. THE GULBRAND-LEUNG COST ANALYSIS METHOD: DERIVATION AND DISCUSSION

The Gulbrand-Leung method of levelized or annual equivalent costs has become widely used. In their original article[1/], the authors offered this formulation:

$$FCR = R + SF + ADM + INS + AVT + TAX \tag{1}$$

FCR = fixed charge rate
R = cost of capital
SF = sinking fund depreciation rate
ADM = administrative and general costs
INS = insurance
AVT = ad valorem tax
TAX = income tax

For example, a fixed charge rate of 16.23% per year consisted of a cost of capital of 8%, a sinking fund depreciation rate of 0.58% (8% interest, 30-year life), 1.25% administrative cost, 0.10% insurance, 2.25% ad valorem taxation, and a 4.05% income tax liability. (The notation here differs from that used in the body of the report and is intended to be similar to that used in the original Gulbrand-Leung discussion.)

Income tax liability was expressed through these equations:

$$T_1 = \left(\frac{t}{1-t}\right) \left(\frac{r-Db}{r}\right) (r + d_1 - d_2) \tag{2}$$

T_1 = revenue requirement for income tax
t = effective total income tax rate
r = cost of capital
D = proportion of investment which is debt
b = bond rate
d_1 = sinking fund depreciation rate
d_2 = straight line depreciation

The effect of accelerated depreciation was expressed in this way:

$$\text{Adjustment} = \left(\frac{t}{1-t}\right) ((\text{PW of Depr})(r + d_1) - d_2) \tag{3}$$

$$T_2 = T_1 - \text{Adjustment} \tag{4}$$

T_2 = revenue requirement for income tax allowing for accelerated depreciation
Adjustment = the adjustment for accelerated depreciation
PW of Depr = present worth of the accelerated depreciation expense deduction

The Gulbrand-Leung formulation was revised in work for the Commission by TRW[2] and Knecht[3] who incorporated the tax effect of the investment tax credit:

$$T = \frac{t}{1-t}\left[\left(\frac{r-Db}{r}\right)(r+d_1-d_2) - ((PW\ of\ Depr)(r+d_1) - d_2) - IC\right] - IC \quad (5)$$

T still represents the revenue requirement for income tax liability, and IC represents the impact of the investment tax credit on tax liability.

Parathentically, we may note that the possibility of T being negative -- of a negative income tax liability -- is not considered. T always takes positive values in these studies.

None of these studies shows the logical derivation of the basic form of Equation (5). However, by developing its theoretical basis we can begin to speculate why it is so misleading in practice.

Begin by defining operating income available for distribution to equity and debt as the remainder after normal straight line depreciation and income tax payments have been deducted from net revenue. Net revenue, in turn, means operating revenue less fuel, OM, property, and other taxes.

$$OI = NR - SL - TAX \quad (6)$$

with OI being operating income, NR = net revenue, SL = straight line depreciation, and TAX = income tax liability.

$$TAX = TR(NR - SL - DED) - CRED \quad (7)$$

Here the tax equals the tax rate (TR) times taxable income, and taxable income is net revenue less normal straight line depreciation less deductions (DED). Credits (CRED) are deducted from the preceding amount to determine total tax liability. It should be noted that deductions are those in excess of SL depreciation since SL is explicitly part of Equation (7).

Substituting Equation (7) into Equation (6),

$$OI = NR(1-TR) - SL(1-TR) + TR(DED) + CRED \quad (8)$$

These terms may be rearranged to show net revenue's relationship to them:

$$NR = \frac{OI - TR(DED) - CRED}{1 - TR} + SL \quad (9)$$

This, in turn, is put back into Equation (7), so,

$$TAX = \frac{TR}{1-TR}(OI - DED - CRED) - CRED \quad (10)$$

It turns out that this is equivalent to the Gulbrand-Leung Equation (5). T is of course TAX, and t and TR are tax rate. However, it helps to rearrange Equation (5) somewhat to show its relationship to the logic in the derivation of Equation (10). First, we note that the capital recovery factor -- the amortization rate which will pay interest and retire the principal on a loan -- is equal to the interest rate plus the sinking fund depreciation rate. So CRF = $r + d_1$, CRF being capital recovery factor:

$$\mathrm{CRF} = \frac{r(1+r)^n}{(1+r)^n - 1} = r + d_1 = r + \frac{r}{(1+r)^n - 1} \tag{11}$$

Use DEP to represent (PW of Depr) times $(r + d_1)$; DEP is the amortized present value of acclerated depreciation deductions. SL is the same as d_2, so Equation (5) becomes

$$T = \frac{t}{1-t}\left[(\mathrm{CRF} - \mathrm{SL}) - \frac{Db}{r}(\mathrm{CRF} - \mathrm{SL}) - (\mathrm{DEP} - \mathrm{SL}) - \mathrm{IC}\right] - \mathrm{IC} \tag{12}$$

Equations (12) and (10) are now very similar. CRED repesents credits, the investment credit of IC in Equation (12). Deductions (DED) have two components in Equation (12). One deduction is (Db/r) times (CRF-SL); this represents that part of operating income which goes to debt payment and is non-taxable. The second deduction in Equation (12) is DEP - SL; this is the amortized (or levelized) value of acclerated depreciation in excess of straight line depreciation. Finally, the fist appearance of CRF - SL in Equation (12) represents OI, operating income before deductions and credits.

So it appears that Equations (6)-(10) can offer a respectable logical basis for the Gulbrand-Leung approach. Why, then, does it appear to err? My present conclusion is that Equation (12) fails in two ways. first, the investment tax credit is usually viewed as being distributed over one or more operating years in engineering studies. However, if payments are made for construction as it is in progress, then the investment tax credit may be claimed during the construction period. The difference in timing may increase the financial value of the credit by 50%.

The second error of Equation (12) is the assumption that Db/r is the same each year of plant operations. In fact, bonds would normally be arranged so that the interest payments are very large in early years and then decline. While this permits the utility to make the same annual loan payment each year, it also permits interest deductions to be far larger in early years. Therefore, for both reasons, I conclude that Equation (12) -- even with T = OI -- overstates income tax liability.

Notes and References for Appendix A.

1. K. A. Gulbrand and P. Leung, "Power System Economics: A Sensitivity Analysis of Annual Fixed Charges," Journal of Engineering for Power, October, 1975, pp. 465-472. Notation in the appendix here for Equations (1)-(5) follows that of Gulbrand and Leung in their original article.

2. TRW Energy Systems Management Division, California Electricity Generation Methods Assessment Project, January 30, 1977, prepared for CEC.

3. Ronald L. Knecht, Review and Critique of California Electricity Generation Methods Assessment Project Final Report, May 1, 1977, prepared for CEC.

APPENDIX B. THE PLANT AND FUEL CYCLE MODEL

B1. Variable Accounts and Definitions

B2. Printout (available separately)

B3. Program (available separately)

Note: The printout and program (Apependices B2 and B3) may be obtained by writing to the author.

Appendix B1. Variable Accounts and Definitions

Policy planning variables select the policy options: rate base pricing or the theoretical method; decommissioning cost; etc.

Exogenous variables take values as assumed, and are never altered within an analysis. Examples: capital cost, \$/kWh; interest rate on debt; etc.

Endogenous variables have values that are determined within an analysis. Single-valued variables are the capital recovery factor, the present value of future decommissioning expense, etc.

Dimensional variables generally take different values in each year.

Optimizing variables are used in the theoretical method of price or revenue determination or decommissioning fund estimation. These variables are used in arriving at iterative solutions to the stated problems.

A. Policy Planning Variables

IFUEL -- determines whether fuel cost is amortized with an AFUDC allowance (IFUEL = 1), or treated as an expense when cost is incurred (IFUEL = 2).

IPR -- determines whether revenue and price are determined by the rate base method (IPR = 1), or by the theoretical method of constant real price (IPR = 2).

MANN -- for the decommissioning fund, the annual contribution is the same dollar amount in each year (MANN = 1), or a constant real dollar amount which, in nominal dollars, grows at the general inflation rate (MANN = 2).

MCON -- for the decommissioning fund, contributions are assumed to be exempt (MCON = 1), or taxable (MCON = 2).

MCOST -- decommissioning cost in 1988 dollars is either 10% of construction expenditures (MCOST = 1), or \$83 million (MCOST = 2).

MDINF -- inflation in decommissioning cost from 1988 to the decommissioning period is either 7% (MDINF = 1), or 14% (MDINF = 2).

MEXP -- decommissioning costs may be either expensed as incurred (MEXP = 1), or either the fund or rate base methods may be used (MEXP = 2).

MINT -- interest earnings on the decommissioning fund may be assumed to be tax-exempt (MINT = 1), or taxable (MINT = 2).

MRB -- for decommisssioning costs, either the rate base method may be used (MRB = 1), or some other method (i.e., simple expensing, funding) may be used (MRB = 2).

MTIM -- when the rate base method is used for decommissioning costs, either the present value (MTIM = 1), or the actual future sum (MTIM = 2) is included in the rate base.

B. Exogenous Variables

AOMINF = .045 -- annual inflation rate in annual operations, maintenance, insurance, and administrative cost.

C(k),k = 1,10 -- Comtois' estimate of the proportion of constant, real dollar expenditures which take place in each year of a 10-year construction period. See Table 1.

CER = .14 -- common equity rate of return.

CONINF = .06 -- annual inflation rate in price of conversion of U_3O_8 to UF_6.

CPKW = 1047 -- capital cost, 1978 dollars; $/kW.

CTR = .09 -- California tax rate on corporate taxable income.

DECINF = .07 or .14 -- assumed annual inflation rate in cost of decommissioning.

DISINF = .065 -- assumed annual inflation rate in waste fuel disposal cost.

ENRINF = .08 -- assumed annual inflation rate in enrichment charge.

FABINF = .06 -- assumed annual inflation rate in fuel fabrication cost.

FFTINF = .045 -- assumed annual inflation rate in charge for fresh fuel transport.

FTR = .46 -- Federal tax rate on corporate taxable income.

PRINF = .07 -- in the pure theory method of determining constant real price, this is the assumed overall annual inflation rate at which the total cost of electricity grows.

PTXINF = .02 -- allowed annual adjustment for inflation for property tax evaluation.

RADC = .08 -- annual rate for AFUDC for plant and fuel acquisition.

RINT = .095 -- rate of interest charged on debt for new plant and fuel acquisition; also rate of interest earned by decommissioning fund.

SPTINF = .045 -- annual inflation rate for cost of transporting spent fuel.

TCR = .10925 -- actual rate for the investment tax credit; the product of the nominal rate (11.5%) and proportion of expenditures which qualify (95%).

UOXINF = .08 -- annual inflation rate in cost of uranium ore.

ZNPINF = .14 -- annual inflation rate in capital cost of new plant.

C. Endogenous Single-value Variables

AF -- amortization factor

AITC -- amortized value of investment tax credit; $ million/year.

AMTS -- amortized tax liability over 47 years; $ million/year.

AVEST -- actual sum of investment expenditures; $ million.

CCFB -- for tax treatment of fuel cost, the cost of each of the first three batches; $ million/year.

CFBAT -- for net income purposes, the cost of acquisition of the first three fuel batches; $ million/year.

CRF -- capital recovery factor.

CWDL -- cost of waste disposal and spent fuel transport for each of the last two batches; $ million/year.

ETR -- effective tax rate; effect of California and Federal tax rates.

EVEST -- sum of equity investment expenditures on new plant; $ million/year.

FES -- value of equity investment in fuel acquisition at the end of the construction period; $ million.

FESAT -- future value of equity investment in plant if earning a rate of return equal to the overall equity rate of return; $ million.

FESAT2-- future value of equity investments in plant and fuel acquisition if they earn a rate of return equal to the overall equity rate of return; $ million.

FEST -- sum of equity investments in fuel acquistion; $ million.

FPMT -- annual payment to retire debt on fuel acquisition; $ million/year.

PER -- preferred stock equity rate of return, equal to rate of interest on debt.

PMT -- annual payment necessary to retire debt on plant investment; $ million/year.

PVD -- present value (at the beginning of plant operations) of future decommissioning costs; $ million.

PVTS -- present value (at the beginning of the 47-year period) of tax liability; $ million.

R -- always equal to ROR, the overall rate of return on investment.

ROR -- rate of return on investment, the weighted average of returns to debt and to common and preferred equity.

SD -- sum of decommissioning expenditures; $ million.

SER -- stockholder equity rate of return; the weighted average of returns to common and preferred equity.

SFUEL -- sum of actual expenditures on fuel acquisition; $ million.

T -- real number value of years since first years of operations.

Z -- used to represent RINT.

D. Endogenous Dimensional Variables

A(k) -- in the main program, A(k) adds California deductions which have been calculated in the decommissioning subroutine to those arising in the main program; $ million/year.

ADCOM(k) -- annual payments into decommissioning fund; $ million/year.

AFUDC(k) -- allowance for funds used during construction of the plant; $ million/year.

AFUEL(k) -- actual annual nuclear fuel expenditure; $ million/year.

AMFUEL(k) -- amortization of fuel expense on an annual net income basis; $ million/year.

ANBOR(k) -- annual borrowing for new plant investment; $ million/year.

ANPROF(k) -- annual after-tax profit, i.e., net income; \$ million/year.

AOM(k) -- annual operations, maintenance, insurance, and administrative expense; \$ million/year.

BASCTX(k) -- undepreciated basis for California tax depreciation expense; \$ million.

BASFTX(k) -- undepreciated basis for Federal tax depreciation expense; \$ million.

BASRAT(k) -- plant rate base, beginning of year; \$ million.

CAMFU(k) -- amortized annual fuel cost on tax basis: cost of goods sold; \$ million/year.

CARR(k) -- in rate base method of price determination, the annual revenue requirement for capital; \$ million/year.

CBATCH(j) -- the cost of a fuel batch; \$ million.

CCBAT(k) -- amortized annual cost of a fuel batch for tax purposes; \$ million/year.

CCON(k) -- annual cost of conversion of U_3O_8 to UF_6; \$ million/year.

CDED(k) -- California tax deductions; \$ million/year.

CESAMT(k) -- cumulative value of equity investment in plant when valued at overall rate of return; \$ million.

CEXP(k) -- total annual cash expenditures; \$ million/year.

CF(k) -- capacity utilization factor.

CFAB(k) -- annual cost of fuel fabrication; \$ million/year.

CFRTRN(k) -- annual cost of fresh fuel transportation; \$ million/year.

CGI(k) -- California gross income; \$ million/year.

CINC(k) -- actual cash monies received, including borrowed funds and decommissioning fund interest; \$ million/year.

CITC(k) -- cumulative value of the investment tax credit; \$ million.

CNRICH(k) -- annual cost of enrichment; \$ million/year.

CR(k) -- annual capital recovery in rate base method; \$ million/year.

CSPTRN(k) -- annual cost of spent fuel transportation; $ million/year.

CTI(k) -- California taxable income; $ million/year.

CTX(k) -- California income tax liability; $ million/year.

CTXDEP(k) -- California tax depreciation; $ million/year.

CUOX(k) -- annual cost of uranium oxide ore; $ million/year.

CVEST(k) -- cumulative sum of investment in plant; $ million.

CWASTE(k) -- waste fuel disposal cost; $ million/year.

DCEXP( ) -- name of decommissioning cost and finance subroutine.

DDEP(k) -- depreciation in decommissioning rate base; $ million/year.

DEBT(k) -- debt on investment in plant; $ million.

DECOM(k) -- decommissioning expenditures; $ million/year.

DFINT(k) -- interest earned on decommissioning fund; $ million/year.

DFUND(k) -- decommissioning fund balance, beginning of year; $ million.

DRB(k) -- decommisssioning rate base, beginning of year; $ million.

DREV(k) -- revenues collected for decommissioning fund; $ million/year.

ESAMT(k) -- equity investment in new plant expenditures; $ million/year.

FADC(k) -- allowance for funds used during construction period for fuel acquisition; $ million/year.

FBOR(k) -- annual amount borrowed for construction period fuel acquisition; $ million/year.

FCAP(k) -- portion of payment on fuel debt which reduces principal; $ million/year.

FDEBT(k) -- debt on funds borrowed for fuel acquisition; $ million.

FDED(k) -- Federal tax deductions; $ million/year.

FGI(k) -- Federal gross income; $ million/year.

FINT(k) -- interest on fuel debt; $ million/year.

FTI(k) -- Federal taxable income; \$ million/year.

FTX(k) -- Federal income tax liability; \$ million/year.

FTXDEP(k) -- depreciation in plant for Federal tax purposes; \$ million/year.

FUDEP(k) -- depreciation in fuel rate base; \$ million/year.

FUEL(k) -- fuel expense to be included in net income expense, either cash basis (AFUEL), or amortized (AMFUEL); \$ million/year.

FURB(k) -- nuclear fuel component of rate base; \$ million.

GEN(k) -- generation; billion kWh/year.

NYEAR(k) -- year.

PCON(k) -- price of converting U_3O_8 to UF_6; \$/kg U.

PFAB(k) -- price of nuclear fuel fabrication; \$/kg U.

PFRTRN(k) -- price of fresh fuel transportation; \$/kg U.

PMTCAP(k) -- payment on principal for debt on plant investment; \$ million/year.

PMTINT(k) -- interest payment on debt for plant investment; \$ million/year.

PNRICH(k) -- price of enrichment services; \$/kg SWU.

PRICE(k) -- price or cost of electricity generated by facility; mills/kWh.

PROFAT(k) -- cumulative value of net income when valued at overall equity rate of return; \$ million.

PSPTRN(k) -- price of spent fuel transportation; \$/kg U.

PTX(k) -- property tax payment; \$ million/year.

PTXBAS(k) -- basis for determining property tax liability; \$ million.

PUOX(k) -- price of uranium oxide ore; \$/lb.

PWASTE(k) -- assumed price or charge for waste fuel disposal; \$/kg U.

QCON(k) -- annual quantity of ore converted to UF_6; kg U/year.

QFAB(k) -- annual quantity of fabricated nuclear fuel; kg U/year.

QFRTRN(k) -- annual quantity of transported fresh fuel; kg U/year.

QNRICH(k) -- annual quantity of enriched fuel; SWU/year.

QSPTRN(k) -- annual quantity of transported spent fuel; kg U/year.

QUOX(k) -- annual quantity of uranium ore; lb U/year.

QWASTE(k) -- annual quantity of waste fuel disposal; kg U/year.

RATDEP(k) -- rate base depreciation; $ million/year.

RC(k) -- annual return to common equity in rate base method of price determination; $ million/year.

RD(k) -- annual return to debt in rate base method of price determination; $ million/year.

REV(k) -- annual revenue; $ million/year.

RP(k) -- annual return to preferred stock equity; $ million/year.

SEXP(k) -- income statement expenses; $ million/year.

SINC(k) -- income, consisting of revenue, allowance for funds used during construction on plant and on fuel acquisition, and interest earned on decommissioning fund; $ million/year.

TAXAT(k) -- cumulative value of tax liability when valued at overall return to stockholders' equity; $ million.

TAXEF(k) -- annual total California and Federal income tax liability; $ million/year.

TAXLI(k) -- annual reduction in total California and Federal income tax liability caused by deductibility of interest payments during construction period; $ million/year.

TF(k) -- in rate base method, the assumed Federal income tax liability; $ million/year.

TFTXDP(k) -- depreciation expense of plant investment for Federal income tax purposes; $ million/year.

TRBDP(k) -- total annual rate base depreciation in plant, fuel, and decommissioning; $ million/year.

TRTBAS(k) -- total rate base: plant, fuel (if used), and decommissioning (if used); $ million.

TS(k) -- in rate base method, assumed California state income tax liability; $ million/year.

TSTXDP(k) -- in rate base method, assumed depreciation expense in plant and fuel in California income tax liability determination; $ million/year.

VADC(k) -- cumulative value of construction expenditures and allowance for plant funds used during construction; $ million.

VEST(k) -- actual annual construction expenditures on plant; $ million/year.

ZCASH(k) -- net funds (cash) earned; $ million/year.

ZINT(k) -- interest payment on debt during construction period; $ million/year.

ZITC(k) -- actual amount of investment tax credit; $ million/year.

ZMDRTB(k) -- in rate base method, mid-year value of total rate base; $ million/ year.

E. Optimizing Variables

YDCOM -- used to determine the correct revenue to collect for a decommissioning fund; $ million/ year.

YY -- equal to the balance of a decommissioning fund at the end of 2024; $ million.

ZPRIC -- used in the pure theory method of price determination; mills/kWh.

ZREV -- used to determine the constant dollar revenue requirement necessary to pay debt and taxes on plant and give required after-tax return to equity; $ million/year.

ZZ -- used to compare the difference between intended and actual accumulated net income; $ million.