EFFECTS OF ACCOUNTING RULES ON UTILITY CHOICES OF ENERGY TECHNOLOGIES IN THE UNITED STATES

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PREFACE

Comparison of the costs of power systems is important: additional money spent by the consumer because he does not use the least expensive system is money that cannot be spent elsewhere. Recognizing this, the IIASA Energy Systems Program has developed scenarios that have, to some extent, matched supply to demand using energy technologies in the order of their economic potential: cheapest ones first. The estimates that have been used for nuclear energy indicate that this method is relatively economic, and therefore should be deployed at an early stage.

However, the cost of nuclear power is a controversial subject. Many estimates of the cost of nuclear power in the United States have been published to demonstrate that this technique is not economic. Since the United States is a major energy consumer, it is necessary to examine the issues more closely.

Costing ground rules that are accepted by both the advocates of nuclear power and their opponents in the United States lead to an apparent dominance of capital charges over fuel-cycle costs. The high capital cost of nuclear systems is therefore the chief reason for claims that they are not economic. Yet, over the lifetime of a nuclear reactor, fuel-cycle expenditures will generally be larger than the capital cost. The cause of this discrepancy seems at first to be inflation, since inflation increases capital charge rates. However, standard methods of accounting take this effect into consideration; in particular, inflationary changes in capital charge rates are matched by equivalent increases in properly inflated and levelized fueling and operating costs for all types of systems.

The source of much of the confusion that appears in comparisons of the cost of nuclear and other power systems, particularly in the United States, must therefore lie in the accounting systems that have been adopted. The effects of inconsistent accounting are examined in this paper.

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SUMMARY

Monetary inflation does not change the values of commodities relative to each other, only the value of money relative to commodities. Therefore, it would be expected that a comparison of the cost of technological options would not be inflation-dependent. This is borne out by the fact that when systems are compared using three different methods: (a) reducing all costs to their present worth; (b) reducing all costs to constant-value currency and applying inflation-free discount rates; and (c) levelizing future costs at prevalent discount rates; the same relative cost figures are obtained.

These three methods are used to compare five systems that supply electrical power:

- Light-water reactors (LWR)
- Liquid-metal fast-breeder reactors (LMFBR)
- Coal plants, with scrubbers, burning low-sulfur or processed high-sulfur coal (CS)
- Coal plants, with fluidized-bed combustion of high-sulfur coal (CFB)
- Solar power plants with sufficient storage for base-load use (SS)

Light-water reactors and coal plants with scrubbers are the systems presently in operation, and their "typical" costs can be estimated. Nevertheless, the costs quoted should be considered only as illustrations, since both of these types of plant seem to be subject to potential escalation of capital costs, even in constant dollars. Target costs after development were taken as estimates for the other three systems. Using these data, the cost comparison shows that:

- LWR has a decisive cost advantage over coal
- If target costs are met, LMFBR would be the cheapest system
- If target costs are met, SS is almost competitive with the nuclear systems, and is much cheaper than coal

These conclusions are heretical by currently accepted standards. Spokesmen for US utilities, using cost data similar to those taken here for illustrative purposes, are almost unanimous in their view that coal and nuclear power are closely competitive with each other, and that solar energy is a lost cause even if reasonable cost targets are met. In examining the reasons behind this statement, two major points must be considered. The first is that taxes must be included when comparing prices. Most of these taxes are income taxes, which, because of the capital structure of the utility industry, are effectively capital-cost taxes. This severely penalizes solar power, but does not significantly affect the comparison between nuclear power and coal. The second is that it is common to compare systems using fully inflated capital charge rates, but with operating costs levelized over only a fraction of plant life. This "mixed-mode" accounting does not take the later economic value of the plant into consideration. This economic value depends largely on the recurrent costs, being much higher for plants for which the recurrent costs are low, i.e., nuclear, and especially solar, installations. When uncertainty is considered as a planning factor, however, it is precisely the systems with high recurrent costs that have the greatest likelihood of cost escalation, in an absolute sense. The bias introduced by ignoring the future economic value of the plant is therefore in the wrong direction to counteract the factor of uncertainty.

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1 INTRODUCTION

Engineering economics is the art of determining the cost of a manufactured product. To the extent that this determination is correct, the art might also claim to be a science. However, the definition of a "correct" cost has many subjective elements. Even when a plant has been bought for a known sum of money, operating costs are available, and resource inputs can be obtained from a fully developed market, a determination of the overall cost is dependent on future expectations. This arises because capital costs are recovered out of future earnings, and future operating and resource costs affect the expected market for, and value of, the product. The art, therefore, may be described as judicious forecasting of future events, while the science is the use of these forecasts to draw conclusions.

In a period of inflation, the standard forecast is that the cost of purchased goods and services will increase at a constant relative rate in current dollars (i.e., in dollars of account at the time of purchase). For example, if an inflation rate of 6% per year is forecast, steel or wood or bread or wages which cost \$1.00 today will cost \$1.06 one year from now and \$1.79 (1.06^{10}) ten years hence. However, future costs are subject to a discount; the value of a dollar used productively today will increase with time. Inflation is a factor in this discounting, and the contribution of inflation to the discount rate exactly cancels the contribution of inflation to future costs. The result of this procedure is to make the *present worth* of future costs insensitive to inflation; they can effectively be calculated in uninflated, constant dollars. This is both a logical and a conceptually satisfying result, since it eliminates the consequences of a forecast containing an extrinsic factor (the value of money) and essentially puts currency on a "goods and services" basis.

Since the present worth of future expenses can be calculated in a robust fashion, it seems at first glance that the cost of a process can be obtained simply by adding this value to the capital expenses which have been accrued up to the time of plant operation. Capital costs plus present worth of future costs must be covered out of future income. Regardless of how this income is to be realized, the process which has the smallest amount to recover is the cheapest; and other things (e.g., external costs) being equal, the cheapest system is the one to adopt.

However, things are not always as simple as they seem, as we shall see. To understand the reasons for this, it is necessary to recapitulate some of the standard practices in engineering economics.

2 REAL INTEREST

Both classical and Keynesian economics predict that the actual interest rates charged, minus the prevailing rate of inflation, will tend toward a constant value. However, a number of authors have pointed out that changes in the distribution of income, especially between wage-earners and entrepreneurs, can affect the value of this constant. Since distributional changes are functions of the social structure, only long-term trends may be expected to produce a real effect. Dramatic events such as wars, great economic depressions, and very severe inflation would probably cause fluctuations in this value, but secular changes of the basic interest rate might have time constants of the order of 20–30 years: one human generation.

No dramatic events occurred in the economy of the United States between the years 1952 and 1972, i.e., roughly the period between the Korean war and the oil crisis. The end of the period, however, includes the Viet Nam war, which seems to have been financed largely by post-1970 inflation. Figure 1 exhibits the excess of utility bond yields over the rate of inflation in the previous year [taken as the rate of increase of the Consumer Price Index (CPI)] over this period, reduced to "real interest" as a percentage. These data are consistent with the value of 2.75% used by many utility economists to estimate real return on bond offerings. Moreover, the data are also consistent with rates used by both the utilities and the federal government in the 1930s, the only period in the last fifty years during which the CPI remained constant.

Thus, in the rest of this report, the "real" (inflation-free) interest rate will be assigned a value of 2.75% per year, and denoted by I_0.

3 CAPITAL RETURN AND FINANCING CHARGES

Utilities are financed both by borrowing capital at interest, as with bonds, and by selling shares to investors, as with common stock. Since investment carries a risk, the returns made to the stockholders are normally expected to be larger than those made to the bondholders. In the same way that I_0, the inflation-free interest rate, is fixed at 2.75% per year, utility economists tend to use a value of 4% for R_0, the annual stockholder return in the absence of inflation. The difference between I_0 and R_0 is relatively small, as utility investment is considered to be low in risk. A utility is buffered to a certain extent against excessive losses

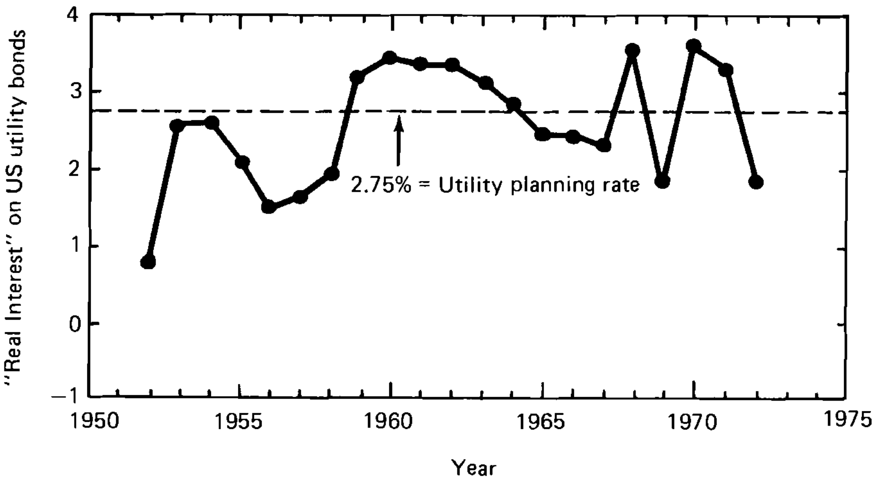

FIGURE 1 Percentage excess of utility bond yields over the rate of inflation in the previous year (as measured by the rate of increase of the Consumer Price Index) for the period 1950–1975 (Statistical Abstract of the United States 1976).

by the monopoly that it enjoys, and prevented from making excessive gains by the compensating regulation of the prices that it can charge.

State regulations, for a variety of reasons, require utilities to raise equity and float bonds at a fixed ratio. While the ratio varies from state to state, it tends to be about 55% stock to 45% bonds. This ratio produces an intermediate value of financial return on capital charges. In the absence of inflation, we can calculate, for $I_0 = 2.75\%$, $R_0 = 4\%$, and an equity : debt ratio of 55:45, the value of the annual financial return, $F_0 = 3.4375\%$.

For planning purposes, then, a utility will consider three factors in estimating costs:

$$\text{Interest rate } I = I_0 + L \tag{1a}$$

$$\text{Investor's return rate } R = R_0 + L \tag{1b}$$

$$\text{Capital finance rate } F = F_0 + L \tag{1c}$$

where L is the expected rate of inflation and I, R, F, L, I_0, R_0, and F_0 are all expressed as a fraction (rather than a percentage) per year. As formulated in Eqs. (1), all rates are taken to be continuously charged.

4 AMORTIZATION

Different plants may have different amortizations, i.e., expected useful periods of service. Amortization cost is computed assuming regular, equal payments to the lender over the period of useful service, i.e., like a mortgage. The yearly payment, under continuous (for example, computed daily) finance charges and payouts is

$$P = DF/[1 - \exp(-FT)] \tag{2}$$

where D is the original capital cost of the plant (e.g., in dollars), F is the finance rate (expressed as a fraction per year), T is the amortization time (years) and P is the payout rate (dollars per year). The present worth of the plant after $t' < T$ years is computed by discounting the payments to be made between t' and T at the finance rate charged. This becomes

$$\begin{aligned} W(t',T) &= \int_{t'}^{T} P \exp(-Ft)\mathrm{d}t \\ &= D[\exp(-Ft') - \exp(-FT)]/[1 - \exp(-FT)] \end{aligned} \tag{3}$$

where $W(t',T)$ is the present worth of an existing plant.

The value of $W(t',T)$ depends on F, the finance rate, which is inflation-dependent. This is not very satisfactory. If F_0 rather than F were used, this external dependence would disappear. Employing Eq. (1c), which relates F, F_0, and the inflation rate, L, and an equation for the present worth of a plant in the absence of inflation, W_0,

$$W_0(t',T) = D[\exp(-F_0t') - \exp(-F_0T)]/[1 - \exp(-F_0T)] \tag{4}$$

the payout rate can be shown to be

$$P' = DF_0 \exp(Lt')/[1 - \exp(-F_0T)] \tag{5}$$

where P' is the payout rate under these altered conditions. In times of inflation, an " inflation-free" mortgage requires that the yearly payments be the same in terms of constant dollars. The factor $\exp(Lt')$ simply corrects for the shrinking value of the currency of the future.

A mortgage contract that requires payment in equal installments of constant dollars, rather than current dollars, is rare; but this type of arrangement is very useful in dealing with high, and particularly with fluctuating, inflation. A first approximation to such a mortgage is beginning to appear on the home real-estate market: escalating payments are geared to the estimated future income of the mortgagee, a parameter that generally follows inflation quite well. Another, closer approximation to this ideal is the periodic reappraisal by non-regulated industries of their capital assets; capital returns are then based on these reappraised assets (replacement cost accounting).

Under this reasoning, $W_0(t',T)$ as given in Eq. (4) is the correct basis for calculating amortization. Amortization is paid as the difference between the actual regular payments and those that would be made if T were infinite. The rate at which capital is charged for amortization can then be specified, in the absence of inflation, as

$$A_0 = F_0/[\exp(F_0 T) - 1] \tag{6}$$

For $T = 35$ years and $F_0 = 0.034375 \text{ year}^{-1}$, the amortization rate, A_0, is $0.01475 \text{ year}^{-1}$, which is equivalent to 1.475%.

During inflation, the use of sinking-fund amortization based on the payment of equal installments in current dollars leads to an underestimate of the real rate of depreciation in the (financially) important early years of plant operation. To compensate for this effect, a fictitious amortization time, T', given ideally by

$$T' \doteq \frac{F_0}{F_0 + L} T \tag{7}$$

is sometimes allowed for income tax purposes. The equity of this adjustment has been the subject of much discussion.

5 CAPITAL PAYMENT RATIO

Without any amortization adjustment, the ratio of capital payment with inflation, P', to that without inflation, P_0, is

$$\frac{P'}{P_0} = \frac{F_0 + L}{F_0} \left[\frac{\exp(F_0 T) - 1}{\exp(F_0 T) - \exp(-LT)} \right] \equiv C \tag{8}$$

Table 1 gives the values of the constant C for $F_0 = 3.4375\%$ and various inflation rates, L.

6 LEVELIZED COSTS

In the preceding section it was shown (Eq. 8) that capital charge payments in an inflationary regime are a factor C higher than those in a noninflationary situation. It shall now be shown that the same ratio is also valid for apparent future costs.

In a noninflating economy, recurring expenses costing one unit today will cost one unit tomorrow and so on. In an inflationary economy, these costs increase as $\exp(Lt)$ in current dollars. To evaluate these costs at a constant rate in current dollars, the concept of levelizing is used. In effect, a banking institution acts as the buffer. When the costs are less than the constant amount allocated, the extra money is put into the bank to accumulate interest; when the costs are greater than this allocation, the savings are withdrawn or, if necessary, some money is borrowed. At the end of the period of levelizing, there should be no net credit or debit if the levelized costs have been computed correctly.

TABLE 1 Dependence of the ratio of capital payment with inflation to that without inflation (C) on the annual rate of inflation (L).[a]

L(%)	$C(= P'/P_0)$
0	1.00
2	1.30
4	1.64
6	1.99
8	2.37
10	2.76

[a] F_0 is assumed to be 3.4375% (see Eq. 8).

The present worth of future payments of recurring costs, per unit annual cost, is given by

$$W_1(T) = \int_0^T \exp(Lt)\exp(-F_0 t - Lt)\mathrm{d}t$$
$$= [1 - \exp(-F_0 T)]/F_0 \tag{9}$$

This is the integral of the annual costs, $\exp(Lt)$, multiplied by the discount factor, $\exp(-F_0 t - Lt)$, evaluated over the operating time T. Note that $W_1(T)$ is independent of L.

To levelize future recurring costs, payments must be made at a constant rate in current dollars, such that the present worth is correctly described. We shall call this rate of payment C, for reasons which will become obvious. C can be found from the identity

$$C\int_0^T \exp(-F_0 t - Lt)\mathrm{d}t = W_1(T) \tag{10}$$

Solving for C, the result is Eq. (8). In other words, the ratio of payments made at a constant rate in current dollars to payments made at a constant rate in constant dollars is, for future recurring costs, the same as the ratio of capital payments with and without inflation. Levelizing future costs is therefore a consistent method of current-dollar accounting.

7 PROPER AND IMPROPER ACCOUNTING

Three internally consistent accounting schemes can be used to calculate the cost of making a product. These are:

- *Present Worth.* The properly inflated and discounted costs of future purchases of material and services are combined with the initial capital cost to give the present worth of the entire operation. This method has the advantage that costing can be carried out in either constant or current dollars.

- *Constant Dollar.* This involves simply reducing all payments over time to constant-value currency, and then computing costs according to deflated discount rates. The method has the advantage of requiring no adjustments, but the disadvantage that constant dollars are more often confused with current dollars than vice versa.
- *Levelized Cost.* This is an internally consistent method of accounting in current dollars. It has the advantage that one always knows how many dollars-of-today are to be paid or set aside; the disadvantage is that it creates a somewhat false impression of cost as a function of time.

All three methods will give the same answer to the question "How does the cost of one system compare with that of another?" That is to say, the ratio of the costs of various systems will be the same whichever accounting method is used. The author happens to prefer constant-dollar accounting, for the simple reason that the effects of inflation must be considered at the beginning of the calculation, but this is only a matter of taste.

Constant-dollar and levelized-cost accounting must *not* be mixed, however, since these methods do not express costs in the same units. In fact, levelized costs are not really current-dollar costs, but current-dollar-equivalent costs; the time factor affecting cost is obscured by the levelizing technique. Nevertheless, in inflationary times, one can say that levelized costs are related to constant-dollar costs by the factor C of Eq. (8). In particular, if the capital costs are calculated in current dollars (i.e., with the effects of inflation included in the discount rate), but future costs are put on a constant-dollar (i.e., first-year-cost) basis, the contribution of future costs to the economics of the system is being grossly underestimated. However, this specific misrepresentation is so common in comparing energy systems that it can almost be described as orthodox.

8 ILLUSTRATIVE EXAMPLES

The cost figures for a variety of types of electrical power plant provide a frame of reference for further discussion. It is hoped that the numbers quoted are "realistic," though only in the sense of being typical of expected costs at the time of commissioning. The following systems will be examined:

- Light-water nuclear reactor (LWR)
- Liquid-metal fast-breeder nuclear reactor (LMFBR)
- Coal plants, with scrubbers, burning low-sulfur or processed high-sulfur coal (CS)
- Coal plants, with fluidized-bed combustion of high-sulfur coal (CFB)
- Solar power plants with tower-type collector installation and thermal heat storage (SS)

TABLE 2 Capital costs (1978 $ per kW electric) and economic lifetimes (years) of electrical power plants.

Plant type	Cost	Plant lifetime
LWR	815	35
LMFBR	975	35
CS	550	35
CFB	650	35
SS	2,500 (1923)[a]	70 [35]

[a]Cost less residual value after 35 years, that value discounted to present worth at a rate of 3.4375% per year.

Capital costs for each of these five types of plant are set out in Table 2. In each case, the assumed value is the cost which might be reached *after* full development has taken place. Practically, this means that only the costs for the LWR nuclear and the coal-with-scrubbers (CS) plants are based on working experience. (However, the costs of both coal and nuclear power plants may still be escalating in constant dollars, though in both cases there is scope for technical improvements – and hoped-for improved costs – in what are still immature technologies.) In each case, a plant is to be placed in service in 1978, and the capital cost is expressed in 1978 dollars. All plants have a base-load capacity factor of 65%, although their costs are expressed in terms of nameplate rating. Economic plant lifetimes are also listed in Table 2.

The LWR data of Table 2 are based on midrange values from estimates of LWR costs prepared for the CONAES study of the National Research Council (in press). This procedure led to a basic figure of $675/kW; $150/kW was added to this figure for the cost of the critical reactor core, and $10/kW subtracted for the present worth of residual core value at the end of plant life. The LMFBR cost quoted is, in contrast, a target value. A common target for the capital cost of a developed LMFBR is 1.25 times the cost of an LWR. This leads to a basic figure of $845/kW, to which was added $150/kW for the critical reactor core, and from which was subtracted $20/kW for the present worth of residual core value at the end of plant life.

The CONAES LWR midrange cost is again the reference case for the coal plants, the cost being adjusted on the assumption that coal plants with scrubbers cost 0–20% less than LWRs, the core charges being excluded. This type of plant is therefore costed at 80% of the basic price of an LWR, rounded upward to the nearest $50/kW. For the fluidized-bed plant, however, the value is entirely arbitrary. Many estimates of the cost of developed coal fluidized-bed (CFB) plants predict that the capital costs will be lower than those of coal plants with scrubbers (CS). If this is so, then there is no point in considering coal with scrubbers any further, for, as shown below, the recurring costs of the CFB plant would also be lower.

An estimate of the developed cost of a large solar power installation can only be a guess, but costs of the order of \$2,500/*peak* kW have been put forward for desert stations which can be adapted to intermediate load service. This number has been used as it stands, on the basis that the cost of providing thermal storage for conversion of peak capacity to base-load capacity will take up any further economies in plant construction. The number in parentheses is the capital cost corrected for the present worth of plant value after 35 years.

All these plants are large, and large plants tend to be kept in serviceable condition for longer than their conventional write-off time. The estimated life of the solar plant, 70 years, is long enough to be compatible with the idea that it would be superseded only when newer designs requiring less maintenance appear on the market.

Estimates of operating and maintenance (O + M) and fueling (F) costs are listed in Table 3. For the nuclear plants, the fuel costs are those of a fuel cycle with reprocessing, so that LWR and LMFBR can be compared on an equal basis. All steps, including waste management, should be covered under fuel costs. In the case of the two coal plants, however, waste management, including disposal of sludge, is covered under the cost of operating and maintenance.

Again, the costs of operation and maintenance are referenced to the CONAES input numbers for LWR. LMFBR is charged at 10% higher than LWR because of increased plant complexity, CS at 25% higher than LWR due to sludge handling, and CFB (with high-sulfur coal) is strongly penalized for its sulfur-handling needs and consequent high sludge rate. The operating and maintenance cost of solar installations is taken to be half that of LWR plants in view of the smaller work force required.

Light-water reactor fuel cycle costs were calculated using the following data: UO_2 at \$100/kg (marginal price); fabricated UO_2 fuel at \$100/kg; \$100/kg-SWU*; UO_2 reprocessed at \$200/kg; waste management fee of \$125 per kilogram reprocessed; sales credit at \$24/g of plutonium. Advance (or deferred) payments were inflated (or discounted) at 6% per year. Inventory charges are covered under capital costs and are not included here. The use of a 6% discount rate implies constant (1978) dollar accounting within the fuel cycle. The costs are supposed to be those of a fully developed industry.

LMFBR fuel cycle costs were calculated using the following data: fabricated fuel at \$800/kg; UO_2 reprocessed at \$350/kg; waste management fee of \$125 per kilogram reprocessed; sales credit at \$24/g of plutonium; and 6% per year escalation or discount rate on payments. Inventory charges are covered under capital costs and are not included here.

The fuel costs of the coal plants are taken to be the costs of coal delivered to the utility, taken here to be in the Midwest of the United States. This is a region of median transportation charges. Typical values are: high-sulfur coal, \$1.10 per million Btu (about \$30/ton); low-sulfur coal, \$1.75 per million Btu

*SWU stands for Separative Work Unit.

TABLE 3 Assumed operating and maintenance (O + M) and fueling (F) costs (1978 mills[a]/kWh) of electrical power plants.

Plant type	Costs O + M	F	O + M + F
LWR	2.1	6.0	8.1
LMFBR	2.3	2.2	4.5
CS	2.6	17.5	20.1
CFB	5.0	11	16
SS	1.0	0	1

[a]One mill is a thousandth part of a US dollar.

(about \$50/ton); plant heat rate, 10,000 Btu/kWh. These numbers have been adjusted for inflation from data presented by Corey (1977) in 1976 dollars, and are marginal costs (i.e., expected costs of new contracts). They are consistent with the data presented by SRI International (1977).

To make the case of solar power comparable to the others, it is necessary to subtract the present worth of the solar plant 35 years from now from the initial capital cost.

The second column of Table 4 lists the sum of present worth of future expenses, plus sunk capital costs, for all the plants considered. A correction for residual assets after 35 years has been subtracted from the present worth of the solar plant. Table 4 therefore shows the total present worth of all payments to be made throughout the lifetime of the installation. As previously noted, all plants are operated at 65% capacity. This amounts to 5,700 hours per year, or 5,700 kWh per year (kW of capacity). The "present worth" column in Table 4 is derived by multiplying the last column of Table 3 by 5.7 to obtain the annual cost (in constant-value dollars) of operating, maintaining, and fueling per kilowatt of electrical plant. This is then converted to the present worth of total expenses over 35 years of operation by multiplying by the factor

$$f = [1 - \exp(-35F_0)]/F_0 \tag{11}$$

and adding the corrected capital costs. The appropriate discount factor is $F_0 = 0.034375$ since the recurring costs have been calculated in constant dollars.

The third column of Table 4 makes the same comparison using the constant-dollar method rather than the present-worth method. Capital charges are taken at $F_0 + A_0$ on the capital costs of Table 2, dividing by 5.7 to convert \$/kWh per year to mills/kWh, and adding the recurring costs listed in the last column of Table 3. The resulting figures are power costs in constant-value dollars. Finally, the fourth column of Table 4 uses the levelized-cost method, assumes

TABLE 4 Comparison of the cost of various types of electrical power plant using three different accounting methods (common financing of capital and recurring costs).

	Present worth of capital and future costs	Power costs	
Plant type	Present-worth method (1978 $/kW)	Constant-dollar method (1978 mills/kWh)	Levelized-cost method – 6% inflation (mills/kWh)
LWR	1,977	15.12	30.15
LMFBR	1,497	12.90	25.73
CS	2,882	24.83	49.52
CFB	2,506	21.60	43.08
SS	2,039	17.57	35.04

6% inflation, a 12.7-year levelizing period, and presents levelized power costs. Note that the ratio of the costs given in the fourth column to those in the third column of Table 4 is numerically 1.99, as given by Table 1 and Eq. (8).

A number of surprising things can be deduced from Table 4. First of all, a comparison of Tables 2 and 4 shows that the present worth of future expenditure exceeds the capital cost of the plant for LWR and both types of coal plant. Secondly, if the solar plant, with storage, were to achieve its objective of an original capital cost of $2,500/kW, it would be competitive with coal, although not with nuclear power. Finally, the cost effectiveness of the breeder reactor looks extremely hard to beat *if its cost objectives are met.*

It must be stressed that this example is strictly illustrative: that is, the input data are purely arbitrary. Another possibility can be examined, as follows:

Retain the light-water reactor as a reference system, but assume that depletion of supplies forces the price of uranium concentrates (in constant-value dollars) to $200/kg, all other cycle costs remaining constant. The fueling cost of the LWR will then rise to 9.1 mills/kWh. Under what circumstances would the other plants be competitive? The capital costs of both types of coal plant are the values given in Table 2; it is then necessary to calculate the price of coal (low-sulfur for the scrubber system, high-sulfur for the fluidized-bed method) that would lead to a cost-based parity between LWR and coal plants. The operating, maintenance, and fueling costs of LMFBR and solar plants are retained at the values given in Table 3; the capital cost required for the systems to be competitive with LWR must then be calculated. The results of these calculations are given in Table 5. It should be noted that this hypothetical case uses a reference price for uranium which is more likely to be representative of the 21st than the 20th century. It is only possible to guess at which of these targets is most likely to be met at that time.

9 INCONSISTENT ACCOUNTING

The results of Tables 4 and 5 are heretical by current standards; yet the same basic data can be manipulated to produce electricity costs that are much more familiar. All that is necessary is to apply the capital charge rate (15–20% per year) used today by the utility industry. Assuming, for illustration, that the capital charge rate is 16% per year, and continuing to use 5,700 kWh per year capacity, the cost of power can be calculated according to the assumptions of Tables 2 and 3. The capital cost (second column, Table 2) must be multiplied by 0.02807 and the result added to the sum of operating and maintenance (O + M) and fueling (F) charges in the fourth column of Table 3. The power costs calculated in this way are given in Table 6. The results of a utility presentation (Corey 1977) for the two cases of available technology are included in Table 6 for comparison.

TABLE 5 Conditions under which various types of plant would be competitive with an LWR fueled with uranium costing $200 per kg (common financing of capital and recurring costs).

Plant type	Variable parameter[a]	Break-even value (1978 $)
LMFBR	Capital cost	1,592 per kW
CS	Delivered cost of low-sulfur coal	31 per ton
CFB	Delivered cost of high-sulfur coal	21 per ton
SS	Capital cost	2,598 per kW

[a]The other parameters remain at the values given in Tables 2 and 3.

TABLE 6 Power costs (1978 mills/kWh) calculated assuming a 16% capital charge rate and present-day fueling costs.

	Power costs			
Plant type	Capital	Recurring	Total	Utility estimate[a]
LWR	22.87	8.1	31.0	28
LMFBR	27.36	4.5	31.9	
CS	15.44	20.1	35.5	40
CFB	18.25	16	34.3	
SS	53.98	1	55	

[a]From Corey (1977).

An examination of Table 6 would lead to the following conclusions:

- The LMFBR has to achieve slightly better values than the targets stated to compete with the LWR
- Coal could compete against uranium at current prices if the delivered price of coal were somewhat reduced
- Solar power is hopelessly expensive

These are, in fact, the general impressions that recur in common small talk, both among people associated with utilities and elsewhere. Is there a fallacy here? And if so, where?

If a fallacy exists, it must be connected with the capital charge rate of 16%. There are, in fact, two fallacies present:

- Confusion of cost with price
- Inconsistent treatment of inflation

The question of price and cost, which involves the differential effects of taxation, will be considered in the next section. In this part of the discussion, however, it is necessary to note that high capital charge rates are always associated with high basic finance rates, and that these high values arise from including inflation in the rates. In other words, they imply that I, R, and F are being used rather than I_0, R_0, and F_0. If actual initial-year operating, maintenance, and fueling costs are being employed, constant-dollar evaluation is necessary. Under these circumstances, inflation should be subtracted from the capital charge rate, i.e., work with I_0, R_0, and F_0. This would greatly reduce the capital charges given in Table 6. Conversely, if capital charges including inflation are used (essentially, current-dollar accounting), then recurrent costs must be levelized. In an inflationary situation, this causes a considerable increase in first-year costs. To summarize, the data of Table 6 are the products of an inconsistent evaluation: one which includes inflation in the capital charge structure, but which also assumes that recurring costs will *not* inflate. It would be an unusual recurring cost that did not inflate with the general economy; indeed, lack of inflation would represent continuing improvements in resource availability and technical economy. Since costs are being estimated on the basis of fully developed technologies, there is no reason to expect that recurring costs would be free from inflation; decisions made only on the basis of short-term charges are thus intrinsically unsound. Table 4 therefore provides a correct reflection of the situation, while the image produced by Table 6 is fundamentally distorted.

10 COST AND PRICE

The customer pays for more than simply the cost of doing business. "Profit" has already been incorporated into the financing factors, F and F_0, but utility income is also heavily taxed, and this tax is added to the price. It is therefore a transfer payment, rather than a simple cost. It is conventional to estimate that taxes are equivalent to the basic return on equity capital, i.e., that taxes represent half of the gross income from equities. Although there are taxes on both property and income, the latter in fact constitute the major share of the tax bill.

No profit is made on amortization. Since recurrent costs are often financed exclusively by debt, they also tend not to be taxed. In fact, under these circumstances the present worths of future operating costs given in the second and last columns of Table 4 have been slightly overdiscounted; Table 7 shows these costs corrected under the assumption of debt-only financing.

The customer contributes to the taxes paid by the corporation in that the prices charged include the effects of this taxation. That the decision is a social one is exemplified by the fact that consumer-owned utilities pay little, or no, tax. Although consumer ownership may be preferred to investor ownership on

TABLE 7 Comparison of the present worth of future expenses and levelized power costs (6% inflation) of electrical power plants – recurring charges financed by debt.

Plant type	Present worth (1978 $/kW)	Levelized power costs (mills/kWh)
LWR	1,853	32.3
LMFBR	1,551	27.9
CS	3,125	51.9
CFB	2,700	45.4
SS	2,051	38.9

purely ideological grounds, it is nevertheless true that taxes are ultimately a payment to society as a whole for the general services provided to the citizenry. These services are also available to corporate bodies, public and private, and it would therefore seem fair that consumer-owned utilities should also pay taxes. This just serves to illustrate the arbitrary nature of the way in which taxes are levied. Moreover, the appropriate returns from taxes raised from utilities are the identifiable social (external) costs of generating the power, plus the unidentified services which should be allocated to the quantity of power generated. In other words, a combination of excise and value taxes would seem to be more appropriate to the electricity-generating industry than the present taxes on distributed corporate earnings (which are further taxed at the level of the investor's income).

The philosophy of taxation could be discussed indefinitely. Recognizing that taxes are not costs, taxation is not initially considered in the internal planning of the utility. In effect, the utility takes the position that it is merely a collection agent, transferring taxes paid by the consumer to the taxing authority. But at a higher level of corporate planning, taxes must be considered; for the *price* of electricity, which includes taxation, is one of the major factors determining system growth. System growth, in turn, is one of the most important aims of the utility, as this growth tends to make the equity associated with the industry more valuable (i.e., increases the value of stock, *ceteris paribus*), diverting profit for investors into less-taxed capital gains and permitting more self-financing of further investment.

The concern of the utility with prices also cancels out quite effectively any incentive to adopt technologies with high capital costs and correspondingly large investor profit (recalling that profit is made only on capital investment). Since the profit per unit investment is regulated, consideration of the effect of taxes on prices leads to a preference for low-capital technologies.

It may therefore be concluded that planning of utilities is based on the price paid by the consumer, and that the technology with the lowest price will be

TABLE 8 Components of the prices charged by utilities, under constant-dollar and levelized-cost accounting.

Component	Constant dollar	Levelized for 6% inflation	Description
Capital cost	$F_0 = 3.4375\%$	$F_0 + L = 9.4375\%$	Discount rate for capital expenses
Interest	$I_0 = 2.75\%$	$I_0 + L = 8.75\%$	Discount rate for recurring expenses
Amortization	$A_0 = 1.475\%$	$A = 0.3602\%$	
Taxes	$0.55R_0 = 2.2\%$	$0.55(R_0 + L) = 5.5\%$	
Capital + Amortization + Taxes	7.1125%	15.2977%	Capital charge rate against price

TABLE 9 The price of power obtained from different types of plant compared using constant-dollar and levelized-cost accounting. (The cost assumptions are those given in Tables 2 and 3.)

	Constant-dollar price (1978 mills/kWh)			Price levelized for 6% inflation (mills/kWh)		
Plant type	Capital	Recurring	Total	Capital	Recurring	Total
LWR	10.17	8.1	18.3	21.87	16.71	38.6
LMFBR	12.17	4.5	16.7	26.16	9.28	35.4
CS	6.86	20.1	27.0	14.76	41.46	56.2
CFB	8.11	16	24.1	17.44	33.01	50.5
SS	24.00	1	25.0	51.61	2.06	53.7

chosen. Table 8 presents the components of the price calculated using the constant-dollar and levelized-cost methods. Table 9 compares the price of power obtained from different plants under the cost assumptions of Tables 2 and 3, using the same self-consistent accounting techniques as in Table 8. A comparison of Tables 7 and 9 shows that the effect of levying taxes on capital alone is most important for the solar plant. In this case the very high capital cost of the plant makes the taxation burden unusually severe.

11 IMPACT OF UNCERTAINTIES

An argument frequently used in defense of short-term planning horizons is that the future is uncertain. Therefore, it is argued, sunk costs should be recovered as quickly as possible, since the net effect of future uncertainty is to increase investor risk, and this risk has a price. This argument contains some truth, and is the strongest point in favor of the adoption of current-dollar, levelized-cost accounting by utilities. Using this method, capital is actually recovered in the first few years, since the present worth of payments to be made in the distant future is very small.

However, uncertainty of inflation also has its price. If inflation stops, the market value of existing utility bonds increases. If inflation accelerates, the old bonds decrease in value. Utilities can cushion the impact of these changes to a certain extent by refinancing (usually with penalties), while large-scale investors can achieve the same effect using tax allowances. Nevertheless, there is still a financial risk, and the higher the inflation rate, the greater is the risk. The situation with regard to equity is similar, with inflation certainly adding risk to the equity (stock) market.

The investor must respond to this increased risk, and there are some signs that he does so. Figure 1 could be interpreted as an indication that the excess of bond rate over inflation rate rises slightly in a period of high inflation; the "real interest" rate clustered around 2% in the low-inflation 1950s and around 3% in the early and late 1960s when the rate of inflation was higher. However, this tendency is not excessively marked. At most, the real interest rate might have increased by 0.1–0.2% per year for each increase of 1% per year in the inflation rate; however this inference is not statistically strong, and the tendencies noted might have had other causes. The most sound conclusion is that the financial risk associated with fluctuating inflation rates has only a slight influence on financing charges, and that the effects are most probably similar to those produced by increasing the discount rate and the capital charge rate by the same amount.

Any change in the discount rate should also affect future operating costs. The usual estimate of the rate of increase of the recurring costs remains unchanged, however, and to this extent uncertainty *does* require some incremental discounting of future expenses.

The preceding analysis considers only the effects of inflation. What about other uncertainties? It is clear that the estimation of future operating or recurrent costs is more uncertain than that of capital charges and costs. In addition to the fundamental uncertainty of inflation, there are likely to be changes in technology, resource availability, demand, and input-values (e.g., the intrinsic value of labor) which will affect future costs. Predicting these changes is a matter of considerable uncertainty, the uncertainty increasing as the range of the forecast increases.

A qualitative feature of this type of uncertainty is that it tends to be asymmetric. There are always more reasons for increasing real costs than for decreasing them – at least, for operating costs associated with large capital investments. The (Bayesian) curve giving the probability of the recurrent cost being correctly predicted, as a function of the predicted cost, becomes more and more skewed as time goes by (see Figure 2): while the mode tends to remain fixed at a

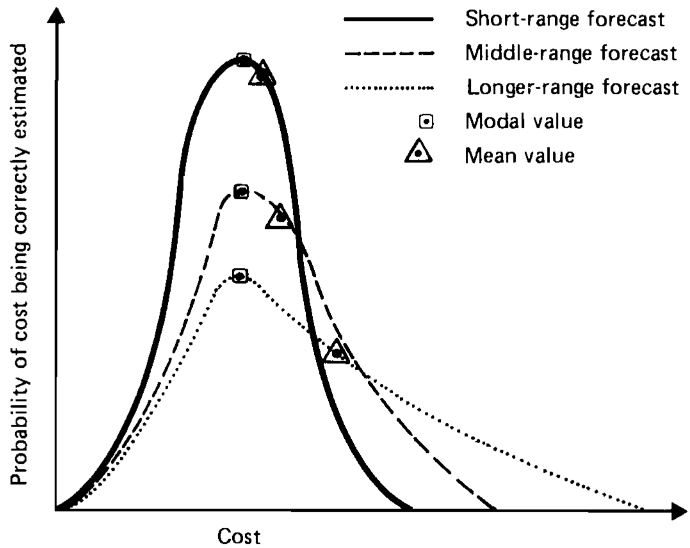

FIGURE 2 Schematic representation of the Bayesian curves showing the probability of the recurrent cost being correctly estimated, as a function of predicted cost, for three different forecast intervals.

constant-value cost equal to the present cost, the mean creeps outward. And it is the mean – the "expected value" – that a realistic estimator must use.

This leads to the qualitative conclusion that uncertainty in forecasting leads to an escalation of expected cost with time, as well as an increased discount rate, i.e., future payments are likely to be larger than they are now, for various reasons unknown.

Summarizing, higher inflation leads to a higher investment risk which is reflected in the charge rate on capital. This is characterized by an elasticity factor, λ; for an inflation rate L, the investor will demand an increased real rate of return λL. The value of λ is not likely to be greater than 0.2. The augmented rate of return produced by this elasticity will also be reflected in the discount rate applicable to future recurrent costs.

Uncertainty in non-monetary conditions affecting the change in costs over time tends to increase the expected values of future expenditure. The rate of escalation is highly dependent on the specific expenses being examined, but could well be higher than the increase in the discount rate caused by uncertainties related to inflation. This is the scenario-dependent escalation rate, σ.

Mathematically, this model can be compared with the previous one by setting up a table similar to Table 8. An inflation rate of 6% and levelized-cost accounting are assumed. A value of the elasticity factor $\lambda = 0.2$ is adopted to test the impact of a large uncertainty in the rate of inflation. Table 10 gives the discount and charge rates obtained.

TABLE 10 Components of the prices charged by utilities, taking into account the uncertainty due to inflation. (35-year amortization with 6% inflation, $\lambda = 0.2$.)

Component	Levelized for 6% inflation	Description
Capital cost	$F_0 + L + \lambda L = 10.6375\%$	Discount rate for capital expenses
Interest	$I_0 + L + \lambda L = 9.95\%$	Discount rate for recurring expenses
Amortization	$A = 0.2633\%$	
Taxes	$0.55(F_0 + L + \lambda L) = 6.16\%$	
Capital + Amortization + Taxes	17.0608%	Capital charge rate against price

TABLE 11 Comparison of the prices charged by various utilities, allowing for the uncertainty due to inflation, and using different values for the scenario-induced escalation of recurrent costs (σ). All values in mills/kWh. (35-year levelizing, 9.95% discount – see Table 10.)

		$\sigma = 0\%$ per year		$\sigma = 1\%$ per year		$\sigma = 2\%$ per year		$\sigma = 3\%$ per year	
Plant type	Capital charge on price	Recurrent cost	Total price	Recurrent cost	Total price	Recurrent cost	Total price	Recurrent cost	Total price
LWR	24.4	17.5	41.9	20.3	44.7	23.7	48.1	28.1	52.5
LMFBR	29.2	9.7	38.9	11.3	40.5	13.2	42.4	15.6	44.8
CS	16.5	43.4	59.9	50.3	66.8	58.9	75.4	69.7	86.2
CFB	19.5	34.5	54.0	40.1	59.6	46.9	66.4	55.5	75.0
SS	57.6	2.1	59.7	2.5	60.1	2.9	60.5	3.4	61.0

Table 11 shows prices calculated from the data of Table 10. Levelized accounting over 35 years is assumed. The scenario-induced rate of escalation of recurrent costs is varied in the range 0–3%. Assuming 6% inflation, this means that recurrent costs increase at a rate between 6 and 9%, with a discount rate of 9.95%.

Comparing Table 11 with Table 9, it can be seen that at low "scenario escalation" rates, (0–1% per year) the qualitative assessment of the various technologies remains essentially unchanged. At "scenario escalation" rates of 2%, and even more at 3%, technologies with low recurrent costs, LMFBR and solar, improve their relative economic ranking. By and large, however, the results of the model confirm the more naive conclusions given in Table 9.

There is one other way of dealing with uncertainty: shorten the levelizing period. This is often done simplistically. The amortization charge is varied while retaining the rest of the capital charge structure of Table 10. For example, if a 15-year amortization period is taken, the amortization charge of Table 10 is increased to 2.7058%, and the total capital charge rate against price rises to 19.5033%. The levelizing period for recurrent expenses is also reduced to 15 years.

There are many ways of tackling this problem, and the results of a number of approaches are presented in Table 12. The first column of levelized costs refers to the capital charges of Table 10, adjusted as above but with no scenario escalation. In the next column, the present worth of the plant after 15 years, computed from Eq. (3), is subtracted from the original capital cost and the calculation repeated. After 15 years, the present worth of a 35-year (real) amortizing plant is 18% of its original value. The third column of levelized costs carries out the same calculation using Eq. (4), and under these conditions the present worth of the plant after 15 years is shown to be 42% of its original value. Finally, the last two columns list the levelized recurrent costs of the subsequent 20 years of operation, expressed both in dollars of the year of commissioning (1978) and in dollars current at the end of 15 years (1993).

How are these numbers to be interpreted? The data in the first column of costs can be dismissed as being exceptionally naive. They are the result of taking a tax adjustment (the use of a fictitious amortization time) literally, and assuming that the plant has no capital value thereafter. Note that this is the only column which places the price of coal-derived electricity within 20% of that of nuclear power, under the cost figures used in these examples. The method used to obtain the figures in the next column has the virtue of recognizing that this short write-off period does not take into account the value of the plant at the end of that period. However, for reasons discussed previously, the use of a high discount rate underestimates this value, i.e., the sale value of a 15-year-old plant 15 years from now will probably be more than 35% of the original capital cost in constant-value dollars, a number consistent with a present worth of 18%. The data in the third column of levelized costs have been corrected to give the plant a significantly higher present worth 15 years in the future, but may indeed have overcompensated, in spite of the arguments used above. A sale price 82% of the original capital cost, in constant dollars, is predicted 15 years in the future.

The best values to use for the levelized cost after 15 years are likely to lie between the values in these two columns, and could only be evaluated more precisely by estimating future values in detail. Finally, the last two columns also refer to the future value of the plants: the lower the recurring costs over years 15–35, the greater will be the incentive to use the plant. These figures demonstrate the great advantages of nuclear power, in particular the breeder reactor, and the great potential of solar power.

The fourth column of Table 11 (total price, 35-year levelizing, no scenario escalation) can be obtained by multiplying the second column of Table 12 (15-year write-off, no capital value thereafter) by 0.875 and adding to this the fifth column of Table 12 (levelized recurring cost over years 15–35 in 1978 dollars) multiplied by 0.511. These coefficients indicate that the operating costs of the system over years 15–35 are not insignificant in determining the long-term value of the plant.

TABLE 12 Levelized costs calculated after 15 years under various assumptions, and levelized recurrent costs over years 15–35.

Plant type	Levelized costs after 15 years: 15-year write-off	Corrected for plant value using F	Corrected for plant value using F_0	Levelized recurrent costs over years 15–35: 1978 \$	(6% inflation) 1993 \$
LWR	40.3	37.5	33.8	13.0	31.2
LMFBR	40.2	36.9	32.8	7.2	17.4
CS	49.6	47.7	45.2	32.4	77.5
CFB	46.7	44.5	41.5	25.8	61.7
SS	67.3	60.8	52.1	1.6	3.9

12 DISCUSSION

This research was originally motivated by the discrepancy between two cost ratios: the ratio of present worth of future expenses to capital costs; and the ratio of operating and fueling expenses to capital charges, as presented in many discussions on the cost of electrical power. It quickly became clear that all consistent, standard accounting methods (of which the present-worth technique is one) would give the same answers when comparing the costs of various plants. However, systems that combine capital charge rates measured in current dollars with the expenses accrued over the first year or first few years grossly underestimate the contribution of recurring costs to the actual cost during an inflationary period. The effect of this "mixed-mode" accounting is still felt, albeit at a lower level, when prices, rather than costs, are compared.

The recurring costs of fuel and labor are a much larger proportion of the cost of providing electrical power than one is often led to believe. For fossil fuels, *including coal*, these costs are so high that it would take a major collapse of their price structure, or a drastic increase in the relative cost of nuclear plants to make coal-fired systems competitive with nuclear power, i.e., with LWRs as they exist today. Further, looking ahead to future developments, those systems which minimize recurring costs will have a significant advantage over the others. If a breeder reactor (LMFBR) could be provided at twice or three times the cost of a coal-fired plant, and if its target costs for fuel cycle operations are achieved, the breeder reactor immediately becomes the reference (cheapest) source of electrical power. If a solar-electric plant with sufficient energy storage for base-load use could be built at a cost only about four times that of a coal-fired plant, it would be competitive. These capital cost targets are much less forbidding than the goals often cited: factors of 1.25 for LMFBR over LWR, 3 or less for solar power over coal. Indeed, many would argue that a capital cost target for LMFBR twice that of LWR is already within our grasp. (However, it is possible that even the relatively low target suggested here for solar power may not be achieved.)

The same reasoning also suggests that other nuclear electrical-energy generating systems might be more economical than LWRs. One example is the CANDU reactor, which is now being used in Canada. The capital costs of this system are probably less than 50% higher than those of LWRs, when first cores (more expensive for the LWR reactor) and heavy water (for the CANDU reactor) are included in the capital cost. The recurring costs of the CANDU reactor, which requires less uranium, little or no enrichment, and less expensive fuel fabrication, could well be less than half those of an LWR. If these rough estimates can be verified by more careful engineering evaluations, the CANDU reactor could be a suitable power system for the United States today.

In an attempt to reduce the effect of uncertainties, evaluations are sometimes based on projections of the cost for the first few years of operation only. This is an approximation to mixed-mode accounting, particularly when levelized costs in current dollars are being projected. Heuristically, this method can be criticized for ignoring the physical and economic value of the plant beyond the levelizing period. It favors technologies with high recurrent costs even though it is precisely these technologies whose long-term costs are the most uncertain.

In a time of high and uncertain inflation, a utility finds it reassuring to use current-dollar accounting to recover capital investments. Since the present worth of each year's payment decreases rapidly with time, the capital is recovered quickly. However, this does not relieve the planner of his obligation to estimate recurrent costs over the entire plant lifetime. Indeed, the very fact that when the costs of a number of systems are compared after long and short levelizing periods the results are different, shows that great care must be taken in assessing the economic values of the plants at various stages in their lifetimes.

One conceptual flaw in utilizing current-dollar accounting during a period of inflation is the question of discontinuity. Both current-dollar capital payments and levelized recurrent payments generate excess income early in system operation and, in terms of constant-value dollars, the long-term future is subsidized by this excess. Existing plants in a utility system then *seem* to be producing power much more cheaply than is possible for any new plant. The introduction of a new plant is then always seen by the consumer as a diseconomy. This accounting method requires that each application for a new plant be accompanied by an application for a rate increase. Constant-dollar accounting avoids this unpopular measure.

It is sometimes alleged that fuel escalation pass-through allowances (i.e., letting the price paid by the consumer rise to cover the inflating price of fuel) are a prime reason for utilities to prefer high-recurrent-cost fossil-fuel technologies. However, this does not seem to be tenable within the logic of the industry. While pass-through allowances protect the utility against out-of-pocket losses, they also increase the consumer price and inhibit the use and growth of the utility system. The practice of giving pass-through allowances serves to consolidate the position of mixed-mode accounting in the power-generating industry, and any effect this may have on utility planning is a function of the method of accounting employed.

The methods of accounting presented in this report are not new, and have only been presented to illustrate that the basic principles of elementary engineering economics seem to have been violated routinely in utility planning. Neither are the detailed results particularly new. Stauffer *et al.* (1975a,b) have examined the case for the breeder reactor using the accounting methods discussed above (including full levelizing of recurrent costs over 30 years) and came to the same conclusions reached here with regard to economic targets. They also found the comparative costs of coal plants to be high. It is interesting that, despite the intervening period of inflation, these papers, presented in 1975, using quite different input numbers – essentially the cost of plants, fuels, and fuel cycle operations prevalent in 1974 – reached the same conclusions found today. The present report goes further in that it includes solar power in the comparisons, updates the input, and examines the discrepancy between consistent planning results and operational decisions.

Two factors have been omitted from this discussion, and should be explicitly included in any detailed planning operation:

1. It has not been normal practice to collect capital costs in constant-value dollars as these costs are accrued, nor to inflate past expenditure (anti-discount) to dollars of the commissioning year. Adhering to correct practice, could, under present inflationary conditions, add of the order of 20% to the *real* capital cost of most of the plants examined. Plants with high capital costs will therefore suffer in comparison with plants whose capital costs are lower.
2. Any planning operation must include a projection for the capacity of each plant considered. Because of their high operating costs, fossil-fueled plants will be run at a lower level as they grow older. This penalizes them in comparison with other types of plant. It seems almost mandatory that "discounted" capacity factors be calculated in constant-dollar formulations, for the reason discussed with regard to amortization. Otherwise, as with mixed-mode accounting, the long-term economic value is lost. Again, proper accounting improves the comparative rating of systems with low recurrent costs.

The logic behind the regulatory control of utilities has been touched on only superficially. This control includes not only the regulation of prices, but also the socio-economic controls implicit in taxation, licencing, financing requirements and rules, and the granting of franchises. These are regarded as external to the planning of the utility, and will be discussed in a later paper, which will consider social profit and loss.

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