1-1-1988

Economic analysis of the trench liquid metal fast reactor

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by

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A Thesis Submitted to the

Graduate Faculty in Partial Fulfillment of the

Requirements for the Degree of

MASTER OF SCIENCE

Major: Nuclear Engineering

Iowa State University
Ames, Iowa

1988

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ABSTRACT

This research is about a conceptual design of an unconventional liquid metal fast reactor, TRENCH reactor. The purpose is to estimate the power generation costs of the TRENCH reactor, which are composed of capital investment costs, operation and maintenance costs, fuel costs, and decommissioning costs.

A detailed discussion of the methodology adopted for use, annual revenue requirements and levelization cost method through the economic analysis period, is presented. The computer codes for the economic analysis calculations are obtained from Oak Ridge National Laboratory and being modified for the project's needs. Since most of the power generation costs are from capital investment costs, a mainframe computer code, CONCEPT-5 code, is used for the detailed capital cost calculation. In particular, a specific cost estimate for the nuclear steam supply system of the TRENCH reactor is presented. We get the NSSS cost by scaling the cost data estimated by Combustion Engineering, which was prepared for the Economic Energy Data Base Program (EEDB). To assume a 8-year lead time, the capital costs is 82.97 mills/kWh in 1986 year dollars.

To calculate other costs, we use the IBM PC programs. The O&M costs shows a little larger than expected, which is 27.07 mills/kWh in 1986 year dollars. The fuel costs is obtained by assuming a ten-year cycle, which has advantages of less radioactive wastes and making the fuel management easy. The fuel costs is only 5.76 mills/kWh. Since there is no specific estimate for the decommissioning costs, we

linearly scale a site-specific estimate for a 1100-MWe plant and get 0.61 mill/kWh for the TRENCH reactor. Finally, the total power generation costs come out to be 116.41 mills/kWh in 1986 year dollars.

1. INTRODUCTION

This is a report about a conceptual design for an unconventional liquid metal fast reactor. The aim of this report is:

1. to examine and demonstrate the methodologies adopted for the project's needs.
2. to use the computer programs available for economic analysis calculations to estimate the power generation costs for the TRENCH reactor.
3. to make specific calculations for the cost items which are not covered by the computer codes or whose values are quite different from the data sets available.
4. to confirm that the same methodologies, assumptions and data base are used throughout the whole calculation process.

The methodologies used are demonstrated in Chapter 2. The calculation processes are presented in Chapters 3, 4 and 5. The last Chapter is for the discussion and conclusion of the results obtained in the preceding Chapters.

1.1 The TRENCH Reactor

The embodiment of this project is a conceptual design of a low power density liquid metal fast reactor of the pool type, which is located in a pool that is narrow enough to be considered as a "trench" relative to most pool type fast reactors.

1.1.1 Assumptions and realities

The French Phoenix and Superphoenix pool type reactors and the loop type Clinch River Breeder Reactor are typical of classical fast reactor designs. Their designs are based on the following assumptions [1].

1. The market for nuclear power would keep expanding and cause a shortage of natural uranium.

2. The recycle of converted plutonium in a LWR is important because of the increasing price of natural uranium.

3. The plutonium price would be so high that a reactor breeding plutonium efficiently would make a large profit.

4. The expanding market of electricity does not allow enough time to develop new technologies.

5. The capital costs of a breeder reactor could be kept under control by taking advantage of the economics of scale.

Unfortunately, there are some facts which are opposite to the assumptions.

1. We do not have a rapidly expanding market for nuclear power.

2. Both the market price of natural uranium and the substitution value of plutonium in a LWR are low.

3. The capital costs of nuclear power plants have escalated more strongly than the LWR fuel cycle cost.

4. Due to political reasons, the reprocessing of LWR spent fuel is not currently being practiced in the U.S.

5. Since the economy of scale is largely overbalanced by low capacity factors [2], medium power fast reactors attract attention.

Due to the conditions listed above, it is recognized that unless the fast reactors are economically competitive with coal and LWR plants, they will not be deployed commercially soon. Therefore, there is both an incentive to consider new ideas that could result in greater economy, and time to develop them.

1.1.2 Design parameters of the TRENCh reactor

Following those observations in the preceding section, we make some assumptions on the design of the TRENCH reactor.

1. The power density should be low to allow long fuel residence and to provide relaxed performance requirements on all primary components.

2. Breeding is only desirable to the extent that it helps to minimize reactivity swing during operation.

3. The reactor should be designed as physically simple as possible; simple head structure, nothing above the core and no delicate manipulation.

4. To avoid the reaction of Na with air and water, the building atmosphere should be nitrogen.

5. Reactor shutdown should be by a simple mechanism that does not involve the insertion of elements into the core.

6. The structure should be seismic stable.

In response to these assumptions, the current concept of the TRENCH reactor can best be visualized with the aid of Figure 1 [3]. A description follows.

1. At one end of the long (22m) pool are a pair of rectangular primary heat exchangers, with pumps located near the exchanger top in the coolant hot leg.

2. A loading table for core boxes is seen next. The loading table is connected by rails to the core for moving the fuel boxes into the core.

3. The core is composed of 5 fuel boxes with no subassemblies.

4. At the sides of the core are located two sets of control elements. Four "semaphore" blades, containing control poisons, are used as shutdown devices to blanket the core with absorbers. Ten tilting control sheets, also of a poison material, are used to regulate reactivity and longitudinal power distribution.

5. An unloading table to which spent fuel is rolled is next to the core. Fuel management is accomplished by moving the end fuel box to the empty table, moving each of the other boxes one step down, and bringing in fresh fuel from the loading table.

6. Except for maintenance, the only locations which would require routine penetration of the head are above the loading and unloading tables.

7. The guard tank is outside the pool. It has a dual function. First it is to provide secondary sodium containment if there is a leak in the pool. Second it is to provide an open plenum around the pool through which nitrogen could circulate for shutdown cooling.

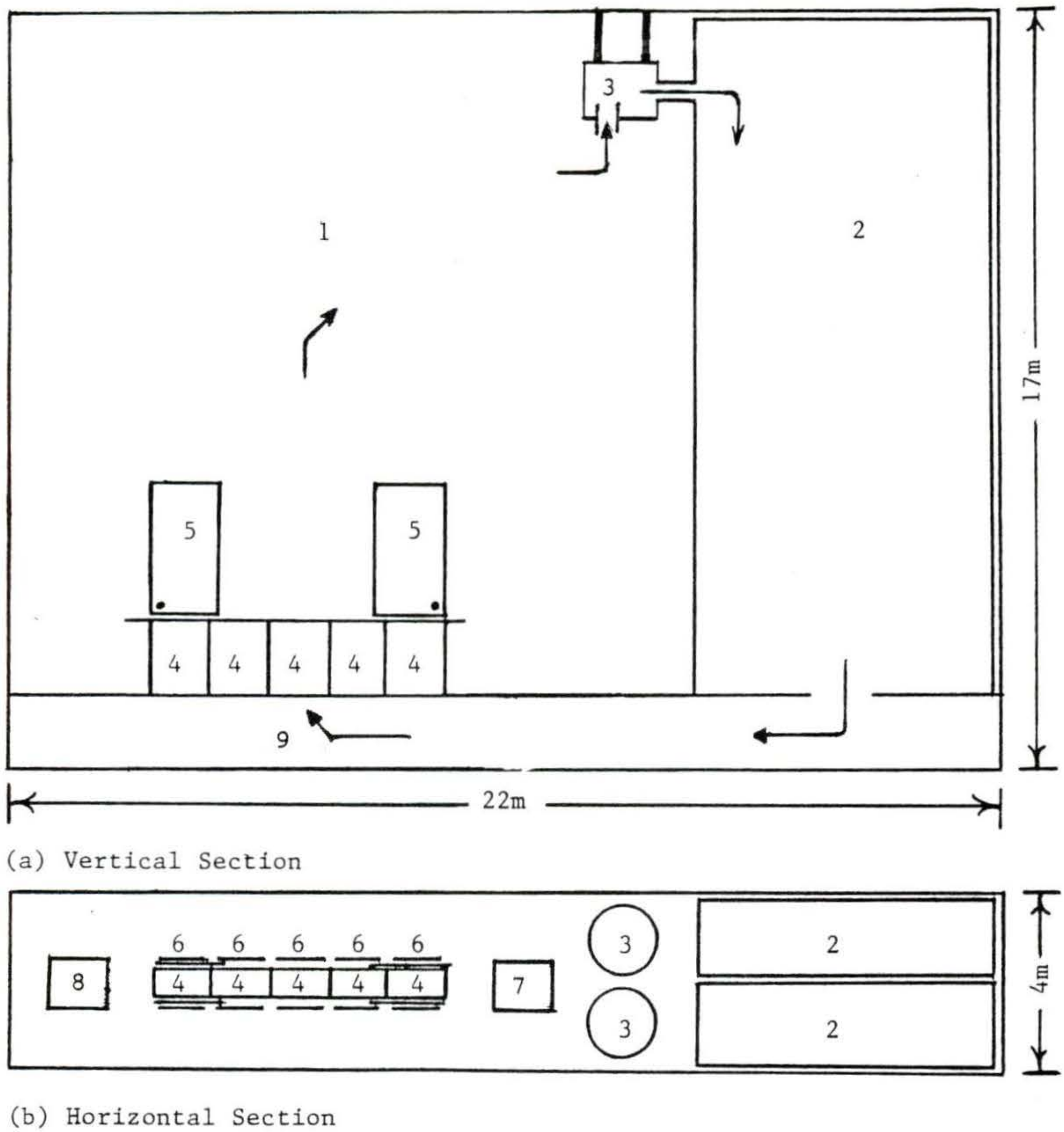
8. To meet seismic safety requirements, the pool will be suspended by cables from piers in the biological shield.

A side view of present configuration is also shown in Figure 1. This configuration has a pipe leading from the outlet of a primary heat exchanger to the cold core inlet plenum and shows the pumps are located at the pool top. The shutdown rods are shown in their "out" position, ready to swing down alongside the core when desired.

1.2 Power Generation Costs

In a general case, the power generation costs are grouped into four categories. These are the initial investment in the plant (capital investment costs), $\overline{P}_C$, fuel costs, $\overline{P}_F$, nonfuel operation and maintenance costs (O&M costs), $\overline{P}_{OM}$, and decommissioning costs, $\overline{P}_{DC}$. These costs can be expressed in either nominal dollars or constant dollars.

In the nominal dollars case,



1. Sodium Pool
2. Heat Exchangers
3. Coolant Pumps
4. Core Modules
5. Safety Elements
6. Shim Elements
7. Loading Table
8. Unloading Table
9. Inlet Plenum

FIGURE 1. Cross section view of the TRENCH reactor [3]

$$\overline{P} = \overline{P}_C + \overline{P}_{OM} + \overline{P}_F + \overline{P}_{DC}$$

and in the constant dollars case,

$$\overline{P}_O = \overline{P}_{OC} + \overline{P}_{OOM} + \overline{P}_{OF} + \overline{P}_{ODC}$$

The calculations of these four terms in each case are given in Chapters 3, 4 and 5.

It should also be noted that some investments will occur before startup and some after the end of reactor life. The revenues and depreciation, however, occur only during the operating life. Note that in the following Chapters we usually express these cost components in mills/kWh by using the conversion

$$\frac{\text{mills}}{\text{kWh}} = \frac{(\$/\text{year}) \times 1000(\text{mills}/\$)}{365\text{x}24(\text{h/year}) \times \text{power(kW)}}$$

Some useful design data which are used throughout the whole calculation process are presented in Table 1. The computer codes used for the calculations and the relationship among them are shown in Figure 2. The CONCEPT code [4, 5, 6, and 7] is for the detailed calculation of capital investment costs. Its output is put into the IBM PC program CAPITAL [8] to get a deductible fraction of capital investment, f, which is used in another PC program FCRATE [8] to get the annual fixed charge rate, FCR. The other IBM PC programs LMROM and NFUEL [8] are for the calculations of the operation and maintenance costs and the fuel costs, respectively. Then the results obtained from the CONCEPT, FCRATE, LMROM, and NFUEL programs and the decommissioning costs are put into the LEVEL program [8] to get the total levelized costs. A more detailed description of each computer code is presented in the following Chapters. Note that since the original cost model stored in the CONCEPT code and the input data prepared for the IBM PC programs are all in 1986 dollars, the calculation processes in the following Chapters will also be in 1986 dollars.

The time schedule and relationship used for calculation purposes are shown in Figure 3. A description of the meanings of each character used in Figure 3 follows.

- O = reference cost model year
- B = present year
- C = steam supply system order year
- D = construction permit issue year
- E = plant startup year
- F = end year of economic study period, also used as plant decommission year
- G = end year of plant life
- L = time period between reference date and first commercial operation date
- M = time period between the reference date and the plant decommissioning date
- m = time period between the reference date and a specified date

- N = time period between the plant startup date and the decommissioning date
- n = time period between the plant startup date and a specified date
- N_{40} = life of project, years

The symbols L, M, N, N_{40}, O, m and n will be used in the following Chapters.

TABLE 1. Data base [8 and 9]

Description	Value
Plant size, MWe	300
Unit number	1
Location	Middletown
Capacity factor, %	70
Steam supply system order year	1992
Construction permit issue year	1994
Startup year	2000
Lead time, years	8
Plant life, years	40
Analysis period, years	30
Reference cost model year	1986
Inflation rate, %/year	5
Escalation rate in excess of inflation rate during construction, %/year	0
Capitalization, %	
Debt	50
Preferred stock	10
Common equity	40
Return on capitalization, %/year	
Debt interest	9.7
Preferred dividend	9
Common equity return	14
Average cost of money, %/year	11.35[a]
Maximum tax rate on corporation, %/year	34 [9]
State income tax rate, %/year	4
Effective income tax rate, %	36.64[b]
Tax-adjusted cost of money, %/year	9.57[c]
Local property tax rate, %/year	2
Tax depreciation method	5-year and 15-year depreciations[d]
Interim replacement rate, %/year	0.5
Nominal interest rate on decommissioning fund, %/year	6.5

[a]From eq. (2).

[b]From eq. (30).

[c]From eq. (18).

[d]See Table 2.

TABLE 2. Recovery percentages for the 1986 Tax Act [8]

Year	Nuclear fuel[a]	Nuclear plant
1	20.0	5.0
2	32.0	9.5
3	19.2	8.55
4	14.4	7.7
5	14.4	6.93
6		6.232
7		6.232
8		6.232
9		6.232
10		6.232
11		6.232
12		6.232
13		6.232
14		6.232
15		6.232

[a]5-year ACRS depreciation.

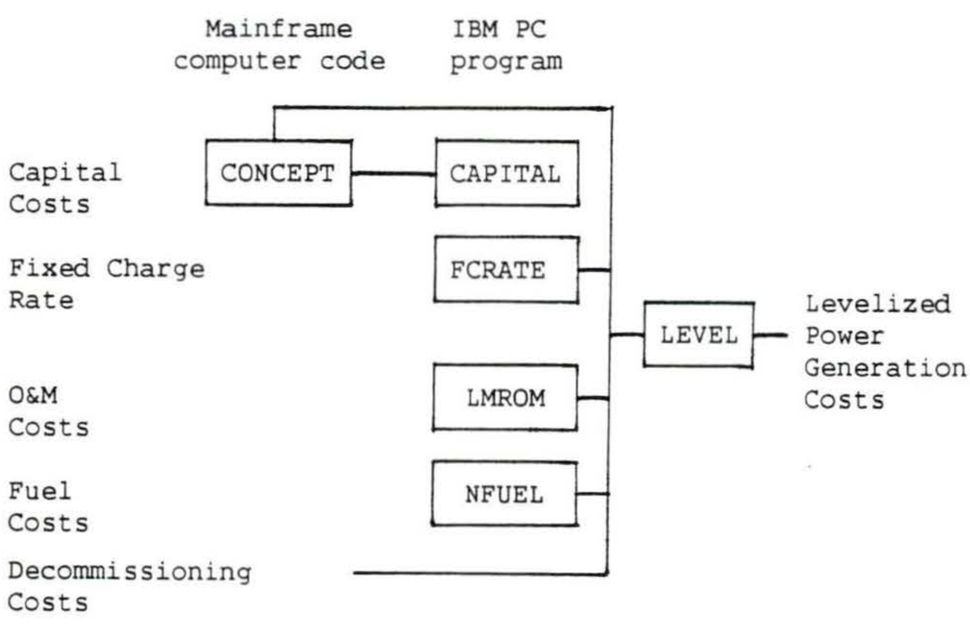


FIGURE 2. Relationship among the computer codes used for the TRENCH reactor calculations

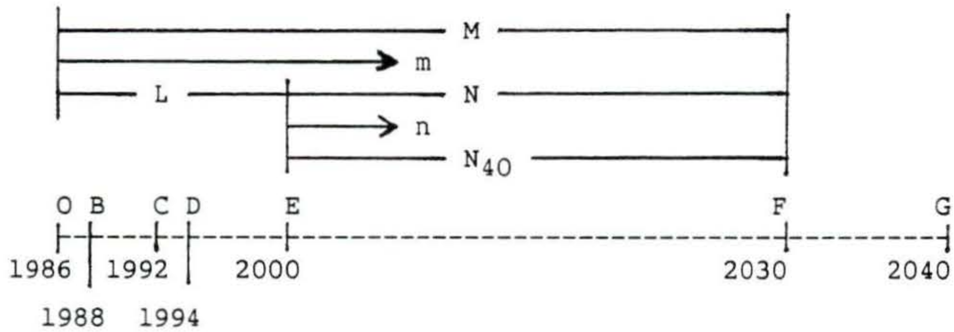


FIGURE 3. Time schedule and relationship used for the TRENCH reactor calculations

2. POWER GENERATION COST METHODOLOGY

There are several methodologies available for calculating power generation costs. The methodology adopted for our project's needs is presented in the U.S. D.O.E. Nuclear Energy Cost Data Base [10, 11, 12, and 13], which is mathematically consistent with basic engineering economic principles and will produce consistent comparisons among alternative energy technologies. The adopted methodology is a year-by-year revenue requirements' procedure together with levelization over the economic life of the plant. They are discussed in Sections 2.1 and 2.2 respectively.

The levelized costs produced by the adopted methodology may either be expressed in dollars indexed to a reference year's buying power (constant dollar levelized cost) or in terms of a levelized cost, which remains constant over the economic life of the plant (nominal dollar levelized cost). The mathematical basis and relationship between both costs are discussed in Section 2.2. Although either method will produce consistent comparative cost results, the constant dollar costs have the advantage of removing inflation from the results and are thus related to the present day conditions. Therefore, it is recommended by NECDB [13] that the results be expressed in the constant dollar form.

2.1 Annual Revenue Requirements

The annual revenue requirements' method determines the necessary year-by-year revenues needed by the utility to pay operating costs, taxes, return on undepreciated capital investment, and capital investment depreciation. In theory, the utility's rates will be adjusted to meet these revenue requirements so that the revenues received equal the revenue requirements for any given year.

There are two methods to calculate the revenue requirements. These are the flow-through accounting method and the normalized accounting method. However, under the tax law as it existed in early 1986, utilities must use normalized accounting of accelerated depreciation and investment tax credits if they are to utilize the accelerated tax depreciation schedules. The normalized accounting method is therefore recommended for privately owned utility economic studies and is discussed in this section.

The basic equation used for calculating annual revenue requirements is

$$R_n = X_1 V_n + D_n^B + O_n + T_n \qquad (1)$$

where

- n = number of years after plant startup
- R_n = annual revenue requirements in year n
- X_1 = weighted average cost of money
- V_n = rate base, also called capital outstanding
- D_n^B = book depreciation on invested capital

- O_n = operating costs
- T_n = income taxes

X_1 is calculated from the capitalization fractions and the returns on the components of capitalization.

$$X_1 = eE + pF + bB \qquad (2)$$

where

- e = rate of return on equity investment
- E = fraction of capital from equity
- p = interest rate on preferred stock
- F = fraction of capital from preferred stock
- b = interest rate on debt
- B = fraction of capital from debt

By substituting eq. (2) into eq. (1), we get

$$R_n = eEV_n + pFV_n + bBV_n + D_n^B + O_n + T_n \qquad (3)$$

The differences between the flow-through method and the normalized method are in the evaluations of the tax term, T_n, and the rate base term, V_n.

The revenue requirements must first be calculated in nominal dollars. Inflation and differential escalation rates are considered explicitly. The reason for including inflation explicitly is to account for the effects of income tax and cost of money that result from inflation.

The overall rate of price change may be divided into two components:

1. escalation due to general inflation as measured by the Gross National Product Implicit Price Deflator.

2. escalation, which is greater or less than the general inflation rate due to real causes such as depletion, new regulations, or changes in efficiency and productivity.

In general, if we assume constant rates of inflation, i, and real escalation, r, then the cost in any year, C_m, is related to the cost in the reference year, C_o, by

$$C_m = C_o(1 + i)^m(1 + r)^m = C_o(1 + g)^m \tag{4}$$

where

- g = overall rate of price change, including inflation.

  $= i + r + ir$

2.1.1 Normalized method

2.1.1.1 Evaluation of the tax

The taxes allowed for normalized revenue requirements are the sum of the current and deferred taxes.

$$T_n = T_{cn} + T_{dn} \tag{5}$$

where

- T_{cn} = the taxes actually paid

  = (tax rate)(revenues - tax deductible costs)

$$= t(R_n - bBV_n - O_n - D_n^T) \qquad (6)$$

- t = effective tax rate
- D_n^T = deductible depreciation for tax purposes

$$= (fI)\ TAXD(n) \qquad (7)$$

- f = depreciable fraction of capital investment

  for tax purposes [8]

$$= \frac{I - (1 - \frac{bB}{X_1})\ AFUDC}{I}$$

- I = total capital investment costs at the start of operation in nominal dollars
- $TAXD(n)$ = recovery percentage at year n for tax purposes, see Table 2 in Chapter 1
- AFUDC = interest incurred during the design and construction period from eq. (34)

Substituting for R_n from eq. (3) and for T_n from eq. (5) into eq. (6), one has

$$T_{cn} = \frac{t}{(1-t)} (eEV_n + pFV_n + D_n^B - D_n^T + T_{dn}) \qquad (8)$$

where

- T_{dn} = deferred taxes due to accelerated depreciation

$$= t(D_n^T - D_n^{SL}) \qquad (9)$$

- D_n^{SL} = tax depreciation computed using the straight-line depreciation method

$$= fD_n^B \tag{10}$$

$$= f\left(\frac{I}{N_{40}}\right) \tag{11}$$

- N_{40} = life of project, years

2.1.1.2 Evaluation of the rate base The deferred taxes are not a free source of capital for the utility since they are used along with the accumulated book depreciation to adjust the rate base. The rate base in the absence of investment tax credits is given by

$$V_n = I - \sum_{j=1}^{n-1} (D_j^B + T_{dj}) \tag{12}$$

The sum of the deferred taxes over the life of the project should equal zero.

According to the tax law of early 1986, the investment tax credits deferred balance may be amortized using either the "above the line" method or the "below the line" method but not both.

2.1.1.2.1 Below the line method In the "below the line" case, the initial base (rate base) is reduced by the amount of the deferred investment tax credits (ITC). The book depreciation in the rate base formula (eq. (12)) is then adjusted by the prorated portion of the credits taken.

$$V_n = (I - ITC) - \sum_{j=1}^{n-1} \left(D_j^B - \frac{ITC}{N_{40}} + T_{dj}\right) \tag{13}$$

where

- $ITC = cfI$
- c = investment tax credit rate

The value of the rate base at the end of project life will equal zero.

2.1.1.2.2 Above the line method In the "above the line" case, the rate base remains as given in eq. (12). But the revenue requirements, R_n, as given in eq. (1), is reduced by the prorated portion of the investment tax credits taken.

$$R_n = X_1 V_n + (D_n^B - \frac{ITC}{N_{40}}) + O_n + T_n \qquad (14)$$

Although both methods of normalizing investment tax credits are valid, we use the "below the line" method in our calculations. However, income tax credits are not applicable for the 1987 tax act [8]. Therefore, we set the income tax credit rate, c, to be zero.

The revenue requirements calculated in the preceding equations are in nominal dollars. They may also be adjusted to constant dollars by dividing by the inflation factor in the intervening years, i.e.,

$$R_{on} = \frac{R_n}{(1 + i)^m} \qquad (15)$$

where

- m = number of years between the reference year o and year n

2.1.2 Year-by-year power cost

The year-by-year cost of power is obtained by dividing the annual revenue requirements by the power produced in that year.

$$P_n = \frac{R_n}{S_n} \quad \text{or} \quad P_{on} = \frac{R_{on}}{S_n} \tag{16}$$

where

- S_n = number of units (kWh) sold in year n

2.1.3 Present worth of revenue requirements

The sum of the present worth of the revenue requirements (PWRR) is a measure of the overall lifetime cost of a project. In effect, it is a single amount of money which is equivalent to the string of annual revenue requirements. It is obtained by discounting the annual revenue requirements to the year of plant startup using the effective cost of money and summing.

$$\text{PWRR} = \sum_{n=1}^{N} \frac{R_n}{(1 + X)^n} = \sum_{n=1}^{N} \frac{R_{on}}{(1 + X_o)^n} \tag{17}$$

where

- X = effective "tax-adjusted" cost of money in nominal dollars

$$= eE + bB(1-t) + pF \tag{18}$$

- X_o = effective constant dollar cost of money, it is related to X and the inflation rate, i, by

$$(1 + i)(1 + X_o) = 1 + X \tag{19}$$

thus,

$$X_o = \left(\frac{1 + X}{1 + i}\right) - 1$$

It should be noted that PWRR is the same whether the nominal dollar revenue requirements and discount rate are used or the constant dollar revenue requirements and discount rate are used.

If alternate projects provide the same benefits (i.e., the same power production), at equivalent economic risks, the project with the lower PWRR is usually the economic choice.

2.1.4 Cash flow

The revenue requirements' approach is an accounting procedure which allocates costs over time. Some of the components of the revenue requirements do not represent actual cash payments in the period in which they are recorded. The measure of actual money transferred is called the cash flow.

Positive cash flows to the utility company are associated with any revenues received, and negative cash flows represent actual capital investment payments, operating costs and taxes paid (current taxes less investment tax credits). Return of capital (book depreciation), deferred taxes, and return on investment are not cash flows but are items which the cash flow must cover in the long run for a project to be viable. Therefore, the cash flow in any year m is given by

$$CF_m = R_m - O_m - T_m - I_m \tag{20}$$

The cash flows are negative during the construction period (m is less than or equal to the lead time) since there are no revenues received during this period. The cash flows are normally positive during the plant operating life.

2.2 Levelized Cost Method

In the levelization technique, an equivalent single price is determined which will produce the same PWRR as the stream of actual year-by-year prices. Levelized power generation costs can be expressed in either constant dollars or nominal dollars. The nominal dollar levelized price is an equivalent price which remains constant over the economic life of the facility. The constant dollar levelized price is an equivalent price, whose value in terms of the reference year's purchasing power does not change. Note that these prices are only figures of merit (equivalent prices) and are not actual prices.

2.2.1 Derivation and Relationship

From eq. (16) and eq. (17), the nominal dollar case becomes

$$\sum_{n=1}^{N} \frac{P_n S_n}{(1 + X)^n} = \text{PWRR} \tag{21}$$

where

- P_n = an equivalent nominal dollar price in year n

Since P_n does not change with time, let

$$\overline{P} = P_n$$

Then, substituting into eq. (21),

$$\sum_{n=1}^{N} \frac{\overline{P}S_n}{(1 + X)^n} = PWRR \tag{22}$$

Since $\overline{P}$ is a constant, it can be removed from the summation to get nominal dollar levelized price.

$$\overline{P} = \frac{PWRR}{\displaystyle\sum_{n=1}^{N} \frac{S_n}{(1 + X)^n}} \tag{23}$$

Since inflation may occur during the operating period, the buying power will change; thus, $\overline{P}$ is in dollars of no single year's buying power. From eq. (15) and eq. (16), the equivalent nominal dollar year-by-year price structure becomes

$$\begin{aligned} P_n &= \overline{P}_O(1 + i)^m \\ &= \overline{P}_O(1 + i)^L(1 + i)^n \end{aligned} \tag{24}$$

where

- $\overline{P}_O$ = constant dollar levelized price
- $m = n + L$ (25)
- L = number of years between the reference year and the year of commercial operation

In the constant dollar levelized approach, the year-by-year price is assumed to rise in nominal dollar terms at the rate of inflation, i. In other words, the price in nominal dollars is indexed to the rate of inflation. Substituting eq. (24) into eq. (21), we get

$$(1 + i)^L \sum_{n=1}^{N} \frac{\overline{P}_o(1 + i)^n}{(1 + X)^n} S_n = PWRR$$

Since $\overline{P}_o$ is a constant and $(1 + i)(1 + X_o) = (1 + X)$, we can rearrange to get

$$\overline{P}_o = (1 + i)^{-L} \frac{PWRR}{\sum_{n=1}^{N} \frac{S_n}{(1 + X_o)^n}} \qquad (26)$$

If energy sales, S_n, are the same for all periods, then let

$$S_A = S_n$$

Also, note that

$$\sum_{n=1}^{N} \frac{1}{(1 + X_o)^n} = \frac{1}{CRF(X_o, N)}$$

where

- $CRF(X_o,N)$ = capital recovery factor for N equal time periods at the real cost of money X_o

An alternate expression for $CRF(X_o,N)$ [14 and 15] is

$$CRF(X_o, N) = \frac{X_o(1 + X_o)^N}{[(1 + X_o)^N - 1]} \qquad (27)$$

Thus, from eq. (23) and eq. (26),

$$\overline{P} = \frac{PWRR}{S_A} CRF(X,N)$$

and

$$\overline{P}_o = (1 + i)^{-L} \frac{PWRR}{S_A} CRF(X_o,N) \tag{28}$$

Therefore, the relationship between the constant and nominal dollar levelized cost is

$$\frac{\overline{P}_o}{\overline{P}} = (1 + i)^{-L} \frac{CRF(X_o,N)}{CRF(X,N)} \tag{29}$$

2.2.2 Evaluation of the cost of money

There is some disagreement on the proper discount rate, X, to be used in such analysis. One thought holds that the direct weighted average cost of money

$$X_1 = eE + bB + pF$$

be used.

The other thought believes that the effective cost of money in levelized situations is less than the direct average cost since interest payments can be deducted as an expense for income tax purposes. This average after tax cost of money is

$$X_2 = eE + bB(1 - t) + pF$$

This cost of money, X_2, has been demonstrated to be mathematically rigorous and the one to be used in discounted cash flow analysis (DCF), which is discussed in Section 4.1.1. In addition, DCF will give the same levelized costs as normalized accounting if investment tax credits are ignored. Therefore, we choose X_2 as the cost of money in our calculations.

The effective income tax rate, t, is

$$t = t_s + (1 - t_s)t_f \qquad (30)$$

where

- t_s = state income tax rate
- t_f = federal income tax rate

Example: If we have $X=X_2=9.57\%$, $N=30$, $i=5\%$ and
for a 2000 plant startup date and 1986 dollars,
then from eq. (19), $X_o=0.043524$ and
from eq. (27), $CRF(X_o,N)=0.0603$, $CRF(X,N)=0.10229$
and $L=2000-1986=14$
therefore from eq. (29), we can get $\frac{\bar{P}_o}{P} = 0.29773$

3. CAPITAL INVESTMENT COSTS CALCULATION

Among the four components of power generation costs, capital investment costs is the biggest part. For the TRENCH reactor, capital investment costs contribute above 70% of the total power generation costs. The capital investment costs are defined as all costs which are related directly to the initial capitalized investment in the plant. They include the return on and the return of the investment, income taxes arising from the investment, property taxes, and interim replacements and/or backfitting costs.

To provide the conceptual capital cost estimates for the TRENCH reactor, we will use the CONCEPT computer code [7] to make the estimate. The cost estimates can be made as a function of plant type, size, location, and date of initial commercial operation. The output will include a detailed breakdown of the estimate into direct and indirect cost accounts similar to the accounting system described in document NUS-531 [16].

3.1 General Methodology

If the power generation rate is constant each year, then, from eq. (26), the constant dollar levelized cost for capital is

$$\overline{P}_{oC} = \frac{(PWRR_C)\ CRF(X_o,N)}{S_A}(1 + i)^{-L}$$

where

- $PWRR_C$ = present worth of revenue requirements for capital investment

In other words, the levelized cost is the annualized revenue requirements divided by the power production in each year.

This annualized constant dollar revenue requirements for capital may also be obtained by using a constant dollar annual fixed charge rate, FCR_o. The annual FCR_o is defined as the fraction which when multiplied by the constant dollar initial capital investment I_o gives the equivalent annual constant dollar cost of those charges which are related directly to the initial investment. A higher FCR value reflects higher market risks. Thus, the annual revenue requirements for capital are $(FCR_o)I_o$, and

$$(PWRR_C)\ CRF(X_o,N)\ (1 + i)^{-L} = (FCR_o)\ I_o$$

so

$$\bar{P}_{oC} = \frac{(FCR_o)\ I_o}{S_A} \tag{31}$$

In the same manner, the power generation costs from capital investment in nominal dollars, from eq. (23), is

$$\bar{P}_C = \frac{(FCR)\ I}{S_A} \tag{32}$$

where

- FCR = nominal dollar fixed charge rate

A discussion of I and I_o follows.

The initial capitalized investment, I, is the total investment cost at the first commercial operation date. It contains the overnight cost in some reference year's dollars, the escalation of these costs between the reference year and the year the money is actually spent, and the interest (AFUDC) incurred between the time the money is spent and the commercial operation date.

If a fraction, h_j, of the overnight cost, C_o, is to be spent at a time, t_j, and if the cost escalation rate between the reference time, t_o, and t_j is g then the actual expenditure at t_j will be

$$C_o h_j (1 + g)^{(t_j - t_o)}$$

Once the construction payment is made, it will accumulate interest until the first commercial operation date, t_{op}. So the incremental investment, $C_o h_j$, will keep accumulating to

$$C_o h_j (1 + g)^{(t_j - t_o)} (1 + X)^{(t_{op} - t_j)}$$

including the AFUDC by the weighted average cost of money, X.

Summing over all construction payments, we can get the initial capitalized investment in nominal dollars, I.

$$I = \sum_j C_o h_j \; (1 + g)^{(t_j - t_o)} \; (1 + X)^{(t_{op} - t_j)} \tag{33}$$

The total AFUDC is

$$AFUDC = I - \sum_j C_o h_j \; (1 + g)^{(t_j - t_o)} \tag{34}$$

and the total escalation is

$$\text{Escalation allowance} = \sum_j C_o h_j [(1 + g)^{(t_j - t_o)} - 1] \qquad (35)$$

Then I_o becomes

$$I_o = \frac{I}{(1 + i)^L} \qquad (36)$$

3.2 CONCEPT Computer Code

A more detailed treatment of the analytical methods used in the CONCEPT code is presented below. Most of the analysis is concerned with the adjustments of costs from a base year and base location to a new year and new location, the extrapolation of base size to other sizes, the projection of cost index data, the escalation costs during the design and construction period, and the calculation of interest during the construction period.

3.2.1 General description

The CONCEPT code consists of three separate computer programs, i.e., CONTAC, CONLAM and CONCEPT-5. At the preoperational level the CONTAC auxiliary program is used to read in the cost-model data, detailed cost breakdowns of reference plants, and to convert the card image dataset to a single unformatted binary record, COMO.

The CONLAM auxiliary program is used to read in historical cost data for factory equipment, craft and white collar labor, and site-related materials from the 23 cities, which are shown in Table 3, and to generate the unformatted datafile, LAMA. Note that unlike the labor and material costs, the factory equipment costs are the same for all locations, reflecting the limited market.

TABLE 3. Cities stored in the LAMA file

No.	City	State
1	Atlanta	Georgia
2	Baltimore	Maryland
3	Birmingham	Alabama
4	Boston	Massachusetts
5	Chicago	Illinois
6	Cincinnati	Ohio
7	Cleveland	Ohio
8	Dallas	Texas
9	Denver	Colorado
10	Detroit	Michigan
11	Kansas City	Kansas
12	Los Angeles	California
13	Minneapolis	Minnesota
14	New Orleans	Louisiana
15	New York	New York
16	Philadelphia	Pennsylvania
17	Pittsburgh	Pennsylvania
18	St. Louis	Missouri
19	San Francisco	California
20	Seattle	Washington
21	Montreal	Canada
22	Toronto	Canada
23	Middletown	U.S.A.

Then CONCEPT-5 program uses the COMO and LAMA files to generate the cost estimates based on the input data prepared by the user. The cost-estimating procedures used in the CONCEPT code are based on the assumption that any central station power plant of the same type involves approximately the same major cost components, regardless of the location or the date of initial commercial operation. Therefore, if the trends of these major cost components can be established as a function of time, location, and plant size, a cost estimate for a reference case can be adjusted to fit any case of interest.

The basic tool of the CONCEPT code is to use the historical equipment, labor, and material cost data to calculate cost indices, separate the plant cost into individual components, apply appropriate cost indices to these components, and sum these adjusted components to get total capital investment costs.

Table 4 indicates the general flow of calculations in the CONCEPT code. Allowance for contingencies are calculated for each two-digit account as percentages of corresponding two-digit account costs. The default percentage for contingencies is 15%.

The total number of lowest level accounts in the reference cost model for the liquid metal reactor is 360. Each account is divided into an equipment, a labor and a material cost component.

3.2.2 Cost index generation and alternation

The LAMA file contains the cost data in 23 cities for the past 15 years in six-month intervals, starting from year 1972.5 to year 1986.5. A regression analysis on the LAMA file would provide escalation rates for equipment, labor, and materials within each two-digit account.

As there are several types of equipment, labor, and material items in the LAMA file, the weighted average unit cost C_n can be represented as

TABLE 4. General flow of calculations in the CONCEPT code

Step	Description
1.	Read in data defining calculations
2.	Retrieve reference plant cost model from the COMO file
3.	Read in data overriding base plant cost model
4.	Retrieve historical equipment, labor, and materials cost data from the LAMA file
5.	Read in data overriding calculated escalation rates
6.	Adjust 3, 4, and 5-digit level reference plant costs to specified plant size, location, date, overtime, and productivity
7.	Read in data overriding calculated costs
8.	Sum all direct and indirect costs
9.	Calculate contingencies
10.	Calculate escalation during construction
11.	Calculate interest during construction
12.	Sum all costs
13.	Develop cash flow information
14.	Print report of cost estimate

$$C_n = \frac{\sum_{k=1}^{k_{max}} f_k C_{kn}}{\sum_{k=1}^{k_{max}} f_k} \qquad (37)$$

where

- f_k = the weighting factor for item k, representing the relative amount of item k used in construction
- C_{kn} = historical cost data for item k at time n

The weighted historical data, except labor productivity, can be extrapolated exponentially as a function of time, t, according to

$$C_n = C_o(1 + \epsilon)^t \qquad (38)$$

Taking the logarithm of both sides, one has

$$\ln C_n = \ln C_o + t \ln (1 + \epsilon) \tag{39}$$

which can also be expressed as

$$Y_n = X + tZ_n$$

where

- $C_o = e^X$

  = average unit cost at the cost-model reference date
- $(1+\epsilon) = e^{Z_n}$

  = escalation rate

The values for C_n and t are known so that a regression analysis using the least squares method can be performed to find C_o and $(1 + \epsilon)$.

Also the evaluation of X_ℓ and Z_ℓ at some location ℓ can be accomplished by solving the following equations.

$$\sum_{n=1}^{n_{max}} Y_n = X_\ell n_{max} + Z_\ell \sum_{n=1}^{n_{max}} t_n$$

and

$$\sum_{n=1}^{n_{max}} Y_n t_n = X_\ell \sum_{n=1}^{n_{max}} t_n + Z_\ell \sum_{n=1}^{n_{max}} t_n^2$$

Once the escalation rates are determined, the design and construction period is divided into 50 elements, each representing a particular point in time. Using eq. (38), the cost indices for equipment, labor, and materials in each two-digit account are assigned to the 50 elements. Therefore, the code can use these cost indices to adjust the reference costs to the steam supply system order date and to determine the escalation during the construction period.

3.2.3 Adjustments to the reference costs

The cost data stored in the COMO file can be adjusted for size, location, overtime, productivity, and overhead burden factors, as shown in eq. (40).

$$\text{Adjusted cost} = \frac{\text{reference cost}}{f_1 f_3} f_2 f_4 f_5 f_6 \qquad (40)$$

Note that all factors apply only to the lowest level accounts available, i.e., the three-, four-, or five-digit level accounts. The first four factors, f_1, f_2, f_3, and f_4 affect only the labor cost component. However, f_5 and f_6 affect all three cost components. A discussion and the calculations of these factors follow.

The CONCEPT-5 code uses 40 hours as a reference workweek. Should overtime be utilized, the overtime efficiency f_1 will influence the costs.

$$f_1 = 1 - \eta(\text{HRS} - 40)$$

where

- $\eta = 0.01$
  = incremental efficiency loss.
- HRS = number of hours in the workweek.

The second cost influence factor is the overtime wage premium, OTP, which is assumed to be double time for craft labor of account 20-91 and one and one-half time for white collar workers of account 92-94. The weighted average wage rate factor can be expressed as

$$f_2 = [40 + OTP(HRS - 40)]/HRS$$

The equation for projecting the labor productivity index for craft labor, f_3, is

$$f_3 = a + b(YRSSS - YBC)$$

where

- YRSSS = steam supply system order date
- YBC = year of reference cost

Since no attempt was made to estimate a productivity factor for the normal 40-hr. week as a function of time or location, the default values are a=1 and b=0. We assume that the labor productivity is constant with time and location, i.e., $f_3 = 1$.

In many instances a contractor will apply a percentage to the site labor costs to cover the overhead burden such as insurance, taxes, and other labor-related costs of a general nature. This adjustment factor can be expressed as

$$f_4 = (1 + COS)/(1 + COB)$$

Then site man-hours, H, for each two-digit account can be expressed as

$$H = \frac{\text{labor cost}}{f_1(\text{COS})W}$$

where

- COB = 0.165

  = decimal amount of overhead burden in the reference model
- COS = decimal amount of overhead burden in the specific case
- W = hourly wage rate for each 2-digit account

To adjust for a specific site at the steam supply system order date, the reference costs are multiplied by

$$f_5 = \frac{A_{new}}{A_{base}}$$

where

- A_{new} = cost index at the specific location and at the steam supply system order date
- A_{base} = cost index at the reference location (Middletown) and at the reference date (1986.00)

To adjust for size, we use the classical exponential scaling factor, f_6.

$$f_6 = a + b\left(\frac{MWe_{new}}{MWe_{base}}\right)^c$$

where

- MWe_{base} = 1311 MWe

The scaling coefficients (a, b and c) are shown in Table 5.

TABLE 5. Scaling coefficients for unit-size adjustments

Account	a	b	c
20	1.0	0.0	0.0
21	0.0	1.0	0.5
22	0.0	1.0	0.6
23	0.0	1.0	0.8
24	0.0	1.0	0.4
25	0.0	1.0	0.3
26	0.0	1.0	0.8
91	0.0	1.0	0.45
92	0.0	1.0	0.2
93	0.0	1.0	0.4
94	0.0	1.0	0.5

3.2.4 Escalation during construction

The analysis described in the preceding section gives the direct cost components at the start year of the design and construction period. The next step is to calculate the escalation during the construction period. The three cost components are each escalated separately at the two-digit account level. The calculations are accomplished by dividing the design and construction period into discrete time steps, evaluating the cash flow for each cost component in each time step, then summing the stepwise cash flows.

Escalation during construction is calculated by using the cost indices for the design and construction period generated earlier. Taking the ratio of the cost index at a certain time point to the index at the steam supply system order date produces the escalation factor, EF, over that interval.

$$EF = \sum_{t=2}^{50} \frac{A_t}{A_{sss}} (CF_t - CF_{t-1})$$

The escalated costs, EC, are

$$EC = D \sum_{t=2}^{50} \frac{A_t}{A_{sss}} (CF_t - CF_{t-1})$$

where

- A_t = cost index at time t
- A_{sss} = cost index at the steam supply system order date
- CF_t = normalized cumulative cash expenditure up to and including time t
- D = total unescalated cost in the year of steam supply system order date

3.2.5 Interest during construction

When escalation is present, the cumulative costs to date T during the design and construction period is

$$ECC = D \sum_{t=2}^{T} \frac{A_t}{A_{sss}} (CF_t - CF_{t-1}) \tag{41}$$

The unescalated cumulative costs, UCC, is

$$UCC = D \sum_{t=2}^{T} (CF_t - CF_{t-1}) \tag{42}$$

Then we can calculate the interest on the escalated costs (eq. (41)), the unescalated costs (eq. (42)), or the escalation itself (eq. (41) - eq. (42)).

$$\text{interest} = \sum_{i=1}^{50} [(\text{cash expended up to and including period } i + \text{interest charges to date}) \times (\text{interest rate}) \times (\text{length of period } i)]$$

The total interest during construction, I_t, is

$$I_t = I_{nt} + I_e$$

where

- I_{nt} = the interest on the total direct and indirect costs
- I_e = the interest on escalation during the design and construction period

The I_{nt} is the sum of the cash flow, CA_t, times the interest rate, r_t, times the time interval, Δt.

$$I_{nt} = \sum_{t=T_s}^{T_c} CA_t \, r_t \, \Delta t$$

where

- T_c = commercial operation date
- T_s = nuclear steam supply system order date
- $CA_t = D \, CF_t$

$$= \sum_{i=1}^{N_a} C_i \ CF_i(t)$$

- C_i = cost of each two-digit account i
- N_a = number of two-digit accounts

If interest is compounded,

$$I_{nt} = \sum_{t=T_s}^{T_c} [CA_t + I_{nt}(t-\Delta t)] \ r_t \ \Delta t$$

The evaluation of I_e requires a time-dependent escalation factor, E(t), defined as below.

$$E(t) = \frac{\sum_{i=1}^{N_a} C_i \ CF_i(t) \epsilon_i(t)}{\sum_{i=1}^{N_a} C_i \ CF_i(t)}$$

where

- $\epsilon_i(t)$ = average escalation factor for each two-digit account i at time t

Then

$$I_e = \sum_{t=T_s}^{T_c} \left[\sum_{t_1=T_s}^{t} C_e(t_1) \ \Delta t_1 \right] r_t \ \Delta t$$

where

- $C_e(t)$ = incremental escalation payment

  $= (CA_t - CA_{t-1}) \ E(t)$

If interest is compounded,

$$I_e = \sum_{t=T_s}^{T_c} [\ I_e(t-\Delta t) + \sum_{t_1=T_s}^{t} C_e(t_1)\ \Delta t_1\ ]\ r_t\ \Delta t$$

3.2.6 Cash flow curve modifications

The calculation of allowances for interest and escalation during the construction period requires a cash flow curve for each two-digit account. A set of two-digit account cash flow curves for each type of reactor is stored in the cost models. The curves are normalized so that the range for both axes is from zero to one. In the reference model, the times 0, 0.25, 1 correspond to the steam supply system order date, construction permit date, and initial commercial operation date, respectively. The CONCEPT-5 code remaps the cash flow curves over the specified time periods.

Due to the assumption that only after the construction permit is received does the majority of work and expenditures begin, the shape of cash flow curves is dependent upon the construction permit date, YRPER.

$$P = \frac{\text{YRPER - YRSSS}}{\text{YRCOP - YRSSS}}$$

where

- YRCOP = commercial operation date

A reference fraction, PO, is 0.25. Should P be different from PO, the cash flow will be compressed or expended such that at the construction permit date of the specific case, the fraction of total expenditures will be the same as that of the reference model. For the CONCEPT code, this reference fraction is set to be 0.1.

The program, in adjusting for the specific case, maintains the level of expenditures at the dates of YRSSS, YRPER, and YRCOP at the same level. The other data points are mapped linearly to achieved a modified curve as shown in Figure 4.

The mapping procedure divides the reference array into two sections. One contains data before the construction permit date and the other after the date. Two straight lines with different slopes define the transformation as shown in Figure 5. By requiring that the P x 50 elements in the new array be equated to the PO x 50 elements in the reference array, a linear equation of the form

$$L = a + bI$$

is generated. Then the Ith element of the new array can be defined by the Lth element of the reference array.

3.3 Nuclear Steam Supply System

Among the 11 two-digit accounts of the CONCEPT-5 code, account 22 contributes more to the total capital investment costs than any other. Account 22 is divided into 72 four- or five-digit lower level accounts.

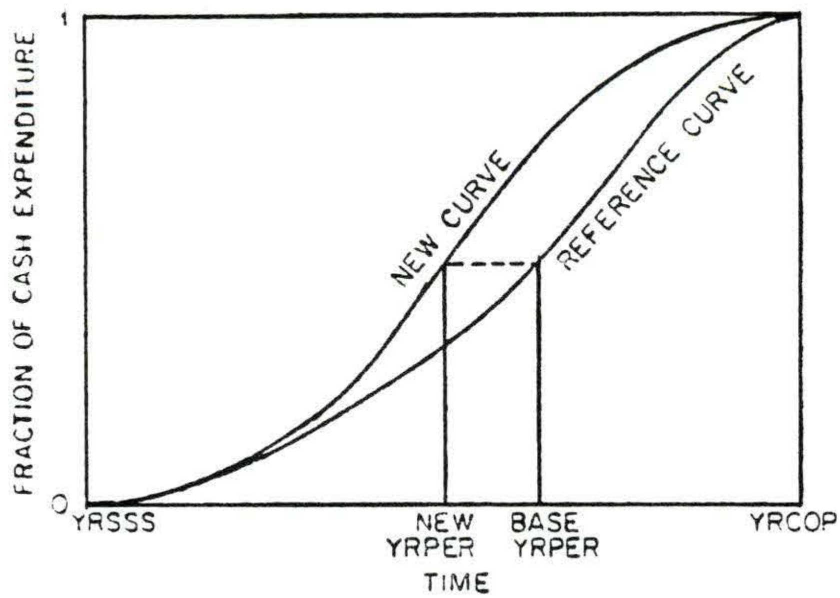


FIGURE 4. Alteration of project's cash flow [7]

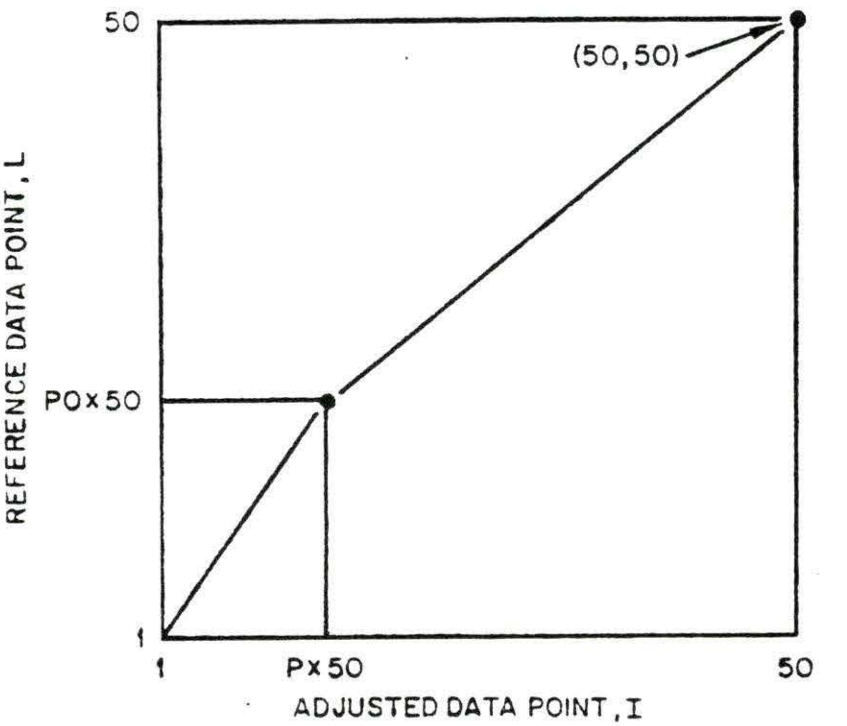


FIGURE 5. Transformation of cash flow data [7]

Among all the accounts of the CONCEPT-5 code, account 220A.1, QUOTED NSSS PRICE, makes up more than 8% of the total direct and indirect costs. Since most of the cost gap comes from the nuclear steam supply system, we only recalculate account 220A.1 and use all the other cost data provided by the CONCEPT code for the other accounts.

The cost data base of the CONCEPT-5 code is based on the design of EEDB Phase VIII [17 and 18]. To calculate the NSSS cost, EEDB adopts the estimate made by Combustion Engineering [19 and 20]. However, the design of the NSSS by C.E. is based on a loop type reactor, TARGET, while the TRENCH reactor is a pool type reactor.

Account 220A.1 in the TARGET reactor is divided into 46 lower level accounts. To calculate the NSSS cost for the TRENCH reactor, we use various scaling factors depending on the cost, weight or volume of the TARGET reactor by the various ratios of flow rate or power size between the two reactors for those accounts which are used by both the TARGET and the TRENCH reactors. For equipment and facilities which are specific to the design of the TRENCH reactor, we make a specific calculation and add the results to account 220A.1. For the sake of comparison, the design parameters of the NSSS of the TARGET and the TRENCH reactors are shown in Tables 6 and 7, respectively.

TABLE 6. Design parameters of TARGET loop type reactor

Description	Value
Plant thermal rating	3800 MWt
Electrical rating	1390 MWe
Type	4 Loops
Primary Na temperature, hot/cold	510/343° C
Primary Na flow rate/loop	35.8×10^6 lbs/hr.
Secondary Na temperature, hot/cold	488/310° C
Secondary Na flow rate/loop	33.4×10^6 lbs/hr.
Steam generator	Two per loop 475 MWt each
Steam temperature	454° C
Steam pressure	2200 psig
Feedwater temperature	243° C

TABLE 7. Design parameters of TRENCH pool type reactor

Description	Value
Plant thermal rating	800 MWt
Electrical rating	300 MWe
Core	
Total flow rate	34.92×10^6 lbs/hr.
Inlet temperature	482° C
Outlet temperature	343° C
Intermediate Heat Exchanger	
Total flow rate (2 IHX)	28.25×10^6 lbs/hr.
Inlet temperature	294° C
Outlet temperature	460° C
Secondary Cycle	
Steam Conditions	425° C, 2175 psig
Feedwater temperature	237° C, 2247.5 psig

3.3.1 NSSS cost breakdown procedures

Some assumptions and considerations used in the estimate procedures of NSSS costs are presented in this section. The detailed cost breakdowns of the NSSS of the TRENCH reactor are shown in Table 42 in Appendix.

1. The original C.E. cost data are in 1980.00 dollars. We escalate these values into 1986.00 dollars by multiplying the values with the inflation factor during the intervening period [13]. This inflation factor is 1.42011.

2. For those components used by both reactors, the scaling equation is

$$C_{TR} = \left(\frac{A}{B}\right)^S \frac{C_{CE}}{U_{CE}} U_{TR}$$

where

- C_{TR} = total cost, weight or volume for the component in the TRENCH reactor
- C_{CE} = total cost, weight or volume for the component in the TARGET reactor
- U_{CE} = number of units for the component in the TARGET reactor
- U_{TR} = number of units for the component in the TRENCH reactor
- S = scaling factor
- A = unit flow rate for the component or power size of the TRENCH reactor

- B = unit flow rate for the component or power size of the TARGET reactor

Note that in the IHX and steam generator A and B are the sum of the flow rates in the tube and shell side of the TARGET and TRENCH reactors, respectively.

3. As examples, the estimate procedures for primary pump cost and steam generator cost are shown in Tables 8 and 9, respectively. The values in Tables 8 and 9 are obtained as follows.

$$15898000 \times 1.42011 = 22576909$$

$$\left[\frac{22576909}{4}\right] 2 \left[\frac{17.46}{35.8}\right]^{0.7} = 6828846$$

$$50808000 \times 1.42011 = 72152949$$

$$\left[\frac{72152949}{8}\right] 2 \left[\frac{14.127+1.373}{16.7+1.78}\right]^{0.7} = 15949053$$

TABLE 8. Estimation of primary pump cost

COMPONENT	TARGET	TRENCH
Unit number	4	2
Flow rate/per pump, 10^6 lbs/hr.	35.8	17.46
Scaling factor	0.7	
Total cost, 1980 dollars	\$15,898,000	
1986 dollars		\$6,828,846

4. If the component is totally different from that of TARGET reactor, we estimate its weight and find its cost by assuming that cost is proportional to weight. The relation is

$$C_{TR} = \frac{C_{CE}}{W_{CE}} W_{TR}$$

TABLE 9. Estimation of steam generator cost

COMPONENT	TARGET	TRENCH
Unit number	8	2
Flow rate/per S.S. 10^6 lbs/hr.		
Shell side/Tube side	16.7/1.78	14.127/1.373
Scaling factor	0.7	
Total cost, 1980 dollars	$50,808,000	
1986 dollars		$15,949,053

where

- W_{CE} = weight of the component in the TARGET reactor
- W_{TR} = weight of the component in the TRENCH reactor.

5. To estimate the mass of a component, we assume that the material densities of stainless steel at the average core temperature 412.5° C and carbon steel are 7720 kg/m^3 and 7860 kg/m^3, respectively [21].

6. As for account 220A.2111, reactor vessel shell, we assume the reactor vessel shell is of regular shape. The configuration of the support system is shown in Figure 6. The vessel weight is obtained by multiplying its volume by the material density. The nozzles weight is proportional to the unit numbers. The weld metal is used around the periphery. Its weight is proportional to the total length of the periphery of reactor vessel shell. The miscellaneous items weight are 2.78% of the sum of all other weights. This 2.78 value is the ratio of the miscellaneous items weight to all other weights in account 220A.2111 of the TARGET reactor.

7. As for account 220A.213, the control rod system, the 4 "semaphore" blades and 10 "tilting' blades are combined into 4 blades as shown in Figure 7 to simplify the calculations. Their weights are obtained by multiplying the volume by the material density.

8. A simplified configuration for the guard vessel is shown in Figure 8. Its weight is obtained by multiplying the volume with the material density.

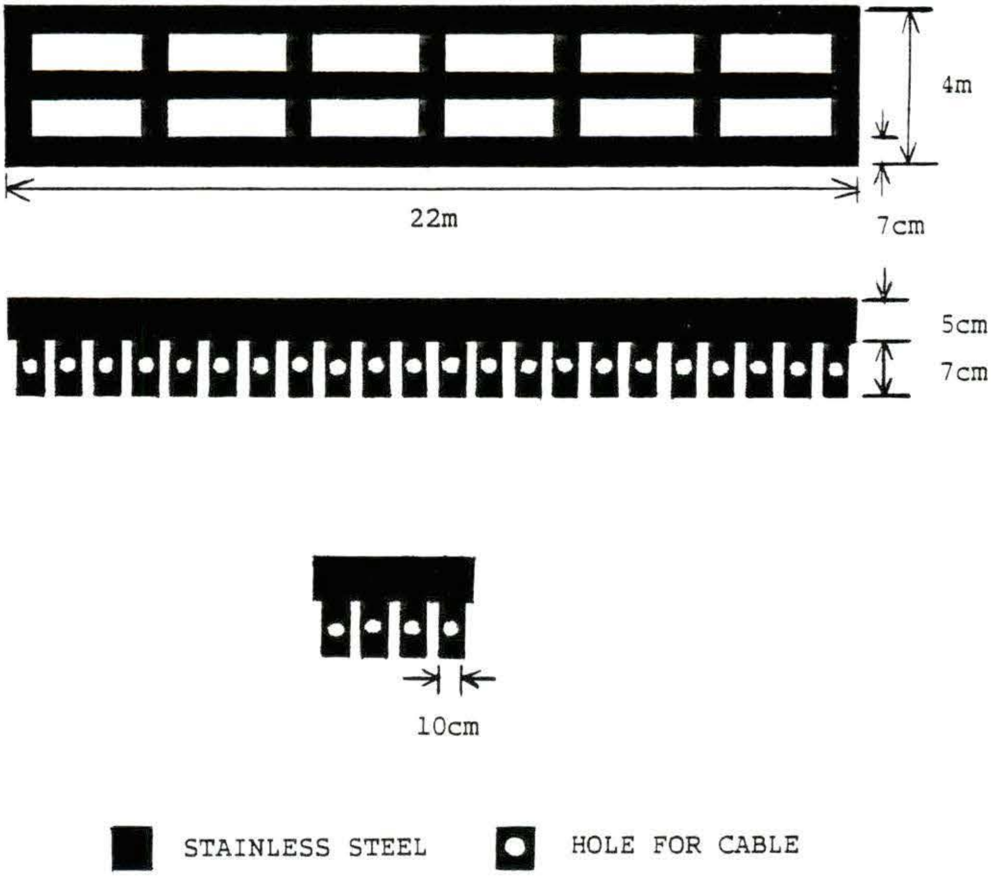


FIGURE 6. Top and side view of the reactor vessel support system

9. Although there is a big difference in power sizes between the TARGET and the TRENCH reactors, we accept the cost of account 220A.27, instrumentation and control system equipments, of the TARGET reactor as the cost for the TRENCH reactor. It is the biggest part of the NSSS costs. If we have a more detailed design for the instrumentation and control system, we would probably get rid of some unnecessary items to reduce the NSSS costs.

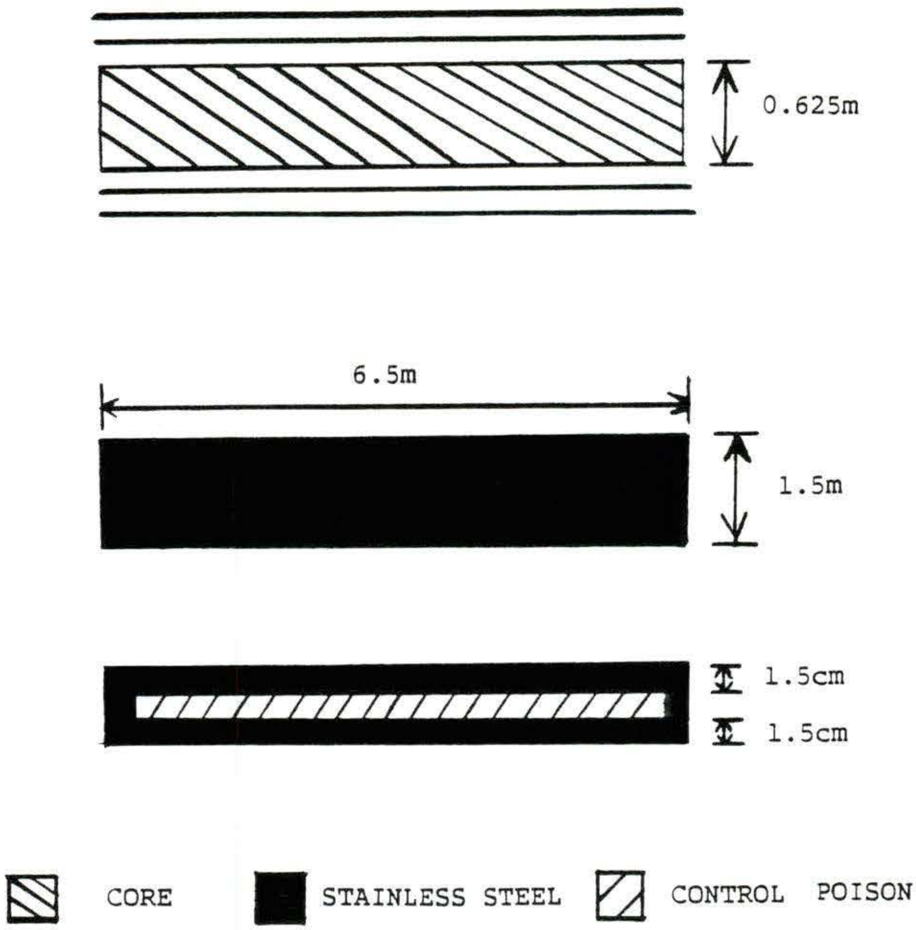


FIGURE 7. Top and side view of the control rod

10. Since sodium will not be placed in the reactor vessel until the commercial operation date, the sodium cost is not included in the NSSS costs. Its weight is obtained by multiplying the reactor vessel volume, 4m x 22m x 17m, by the sodium density at 412.5° C, 853.44 kg/m^3. The weight and the initial charge of sodium contained in the reactor vessel are shown below.

Average temperature	412.5° C
Density [21]	853.44 kg/m^3
Weight	2,814,715 lbs
Unit cost	$5/lb. [22]
Total cost	$14,073,574

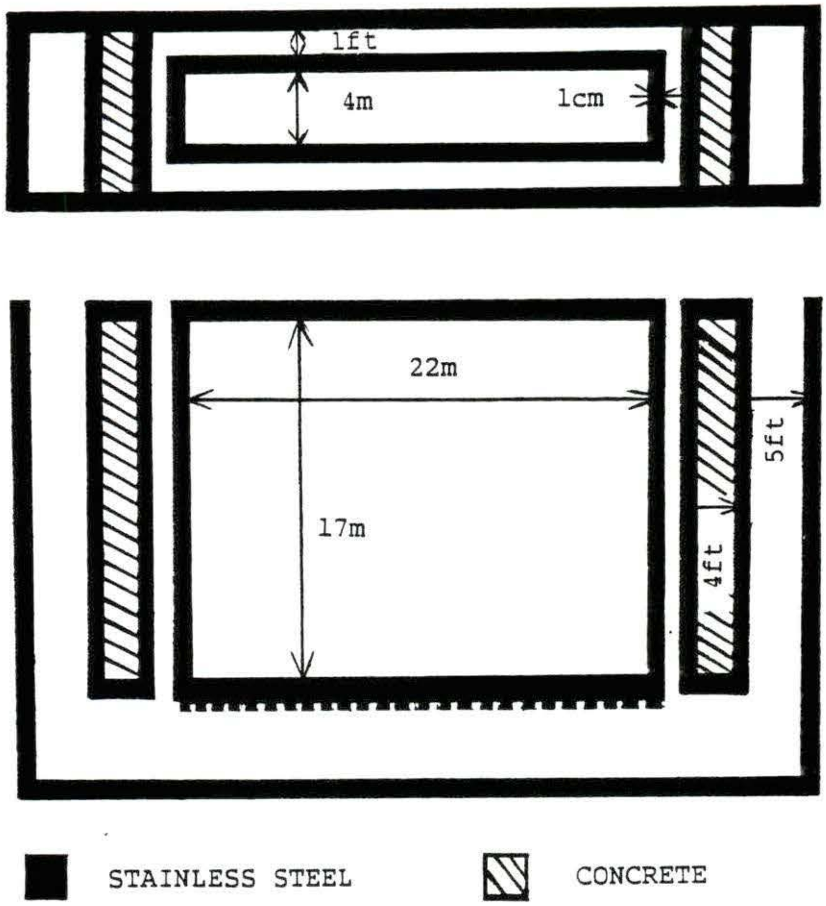


FIGURE 8. Top and side view of the guard vessel

11. Account 220A.23, safeguards system, has not been completely designed. Here we scale the C.E. cost data by 0.7 to get a rough estimate for the component. A configuration of the present design of the safeguards system of the TRENCH reactor is shown in Figure 9.

3.3.2 Cable structure calculations

To provide a better seismic stability, a cable system is used to support the reactor and will serve as a mechanism to isolate the

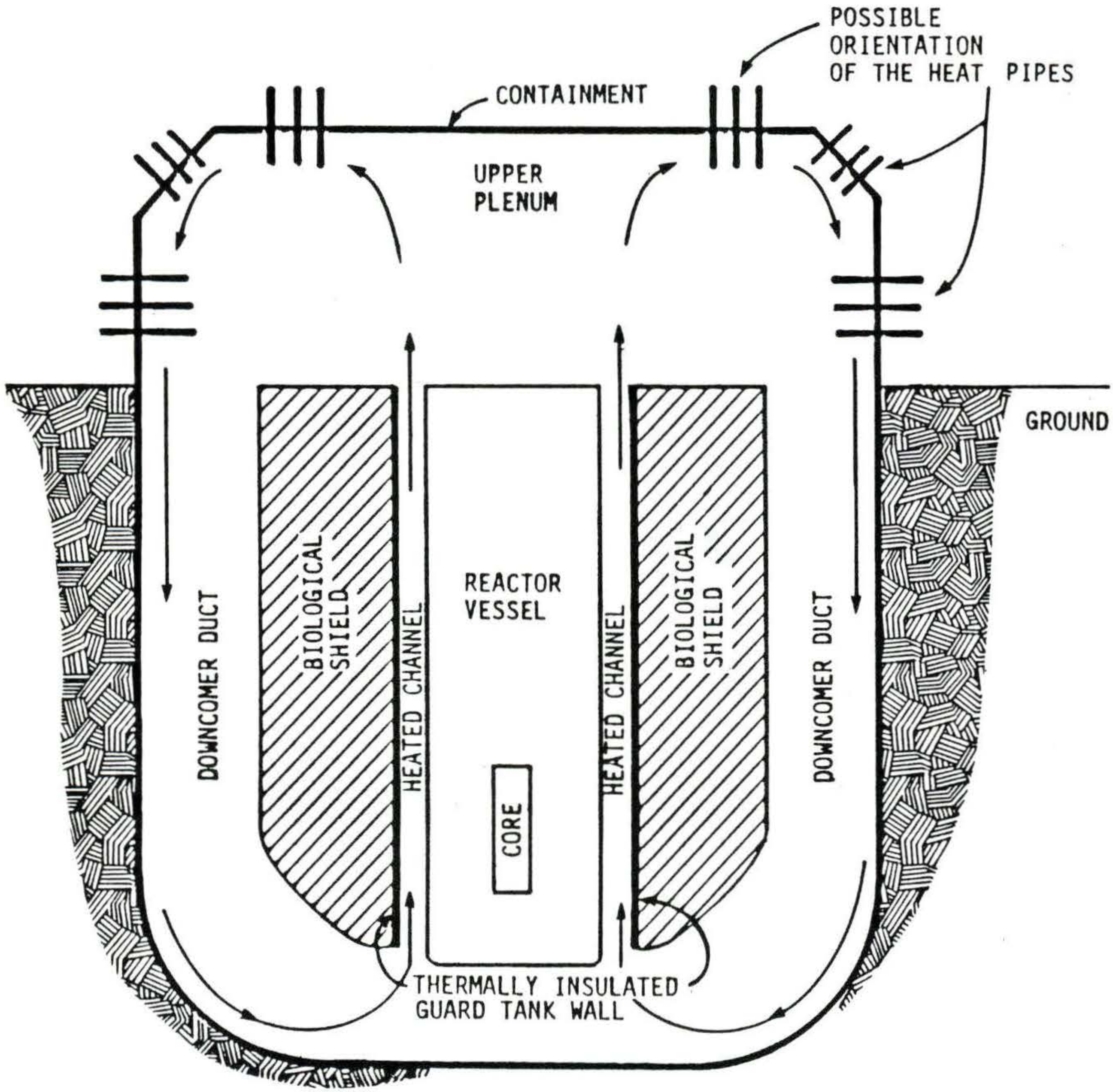


FIGURE 9. Longitudinal view of the decay heat removal system [23]

reactor from seismic accidents. A simplified calculation procedures to estimate the quantity and cost of cables are presented in this section.

1. We assume that the cables are placed in a pool of average temperature 150° F.

2. We assume that the cable is made from carbon steel A212-B and the relations between the temperature and the yield strength for carbon steel A212-B exists for cable.

3. The relations of yield strength with temperature for carbon steel A212-B [21] are shown in Table 10. We can estimate the allowable strength at 150° F to be 35,360 psig by linear interpolation.

TABLE 10. The relation of yield strength with temperature for the carbon steel A212-B [21]

° F	Yield strength	Allowable strength
75	38,000 psi	
700		16,000 psi

4. The weights supported by the cables are shown in Table 11. We multiply it by 1.5 for the unaccounted items and get 7,195,319 lbs.

5. We use 50 pairs of cables. Each cable will support 7195319/100 = 71953 lbs at 150° F.

6. Let A=cross section area of cable
   C=yield strength of cable at 75° F

   Then

$$\frac{38000}{35360} = \frac{C}{71953/A}$$

$$C = \frac{77325}{A}\text{ psi} = \frac{35.07\text{ metric tonnes}}{A}$$

TABLE 11. The weight supported by the cables of the TRENCH reactor

Component	Weight
Account 220A.21	748,790 lbs
Sodium	2,814,715 lbs
Fuel boxes	187,400 lbs (85 metric tonnes)
Account 220A.221	1,045,974 lbs
Total	4,796,879 lbs

For the sake of safety, we assumed that the cable strength at 75° F, C, is below 1/2 of its nominal strength. That is, we choose cable whose nominal strength is greater than 70.1 metric tonnes. From the technical bulletin of "Bethlehem Wire Rope" [24], we thus choose cable of 1.125" diameter.

7. The total length of cables is 7(17x2+22)+43(17x2+4) = 2026 m.

8. The weight of cable is (4 kg/m)x(2026 m)x(2.2046 lb./kg) = 17,866 lbs.

9. The cost of cable is ($1.05/lb.)x(17866 lbs) = $18,759.

3.4 Calculation Results and Comparison

We can sum the results obtained in the preceding sections and get the capital investment costs for the NSSS of the TRENCH reactor as shown in Table 12. Now we can substitute the new value into the cost model to generate a new COMO file and run the CONCEPT-5 code to get the total capital costs for the TRENCH reactor as shown in Table 14. The input parameters used are shown in Table 13. It is noted that the initial charge of coolant, Na, is not included in the CONCEPT code. To complete the estimate, the initial charge of Na is included in Table 14.

TABLE 12. NSSS cost summary of TRENCH reactor

Account	Description	Value	
220A.211	Reactor vessel	$ 14,254,489	(9.74%)
220A.212	Reactor vessel internals	$ 7,281,049	(4.98%)
220A.213	Control rod system	$ 2,757,701	(1.89%)
220A.214	Cable	$ 18,759	(0.01%)
220A.221	Primary heat transport system	$ 18,787,951	(12.84%)
220A.222	Intermediate heat transport system	$ 9,393,718	(6.42%)
220A.223	Steam generation system	$ 22,213,976	(15.19%)
220A.23	Safeguards system	$ 5,497,950	(3.76%)
220A.25	Fuel handling and storage system	$ 9,606,118	(6.56%)
220A.26	Other equipment	$ 24,013,902	(16.41%)
220A.27	Instrumentation & control system equipment	$ 32,456,614	(22.19%)
	TOTAL	$146,282,227	

To show the sensitivity of capital costs to each input parameter, the CONCEPT-5 code was run with different interest rates, lead times, escalation rates, and power sizes while leaving other parameters unchanged. The results are summarized in Tables 15, 16, 17 and 18. Note that the percentage values are the percentage change with respect to the reference case, whose costs are shown in Table 14. In addition, the cost comparisons among the COAL, the PWRB (PWR best experience),

TABLE 13. Data base for the capital cost estimate

Description	Value
Interest rate, %/year	11.35
Escalation rate, %/year	5.0
Contingency, %	
Land & land rights	0
Structures & improvements	21.5
Reactor plant equipment	25
Turbine plant equipment	15
Electric plant equipment	20
Miscellaneous plant equipment	15
Main conditioning heat rejection system	15
Construction services	15
Home office engineering & service	20
Field office supervision & service	20
Owner's expenses	20

the LSPB (large scale prototype breeder), the PWRM (PWR median experience), which are all from the CONCEPT code, and the TRENCH reactor are shown in Table 19. Note that the initial charge of Na is included in Tables 15, 16, 17, and 18, but not in Table 19.

The trends of direct costs, indirect costs, contingency, interest and total capital costs for different values of lead time and escalation rate are shown in Figures 10 and 11, respectively. In Figure 12, we put the three sensitivity curves of lead time (6-12 years), escalation rate (3%-9%), and interest rate (7%-13%) together. The point at which the three curves meet is for our reference case. Figure 13 is for the comparison of capital investment costs of different types of electricity-generating facilities.

TABLE 14. Total capital cost estimate for the TRENCH reactor, in $\$10^6$ of 2000 year dollars

EEDB Account No.	Description	Cost
20	Land & land rights	5
21	Structures & improvements	243
22	Reactor plant equipment	330
23	Turbine plant equipment	131
24	Electric plant equipment	92
25	Miscellaneous plant equipment	79
26	Main conditioning heat rejection system	24
	Total direct costs	904
91	Construction services	177
92	Home office engineering & service	313
93	Field office supervision & service	127
94	Owner's expenses	152
	Total indirect costs	769
	Contingency allowance	333
	Interest during construction	1110
	Total capital investment costs	3116
	Initial charge of Na	14
	TOTAL COST	3130
	$/kWe	10433

From the results obtained above we can note the following:

1. Account 20, land and land rights, does not change with lead time, escalation rate, interest rate, or power size. It even keeps the same value for different types of facilities.

2. Account 22, reactor plant equipment, is the largest among all 11 two-digit accounts. It makes up more than 35% of the direct costs.

3. The interest account is larger than any other cost components including account 22.

4. The interest is most sensitive to the change of lead time and least sensitive to the change of escalation rate. When lead time increases from 8 to 12 years, the interest doubles. Unfortunately, the current typical lead time is 12 years rather than 8 years as we assumed in our reference case [13]. For the case of 12 years' lead time, the interest is above 50% of the total capital costs.

5. Both the long lead time and the high sensitivity of interest on lead time make the capital costs for nuclear plants very large.

6. The effect of 1 year delay in lead time on capital costs is larger than that of 1% increase in escalation rate or interest rate. The interest rate has the least effect on capital costs among all three sensitivity factors.

7. Although the effect of escalation rate on direct and indirect costs are larger than those of lead time and interest rate, the escalation rate does not affect the interest costs as much as that of lead time. Therefore, the total effect of lead time on the total capital costs is the largest among the three sensitivity factors.

8. When the interest rate changes, the direct and indirect costs do not change. Only interest changes with interest rate.

9. If we increase the power size from 300 MWe to 600 MWe, the unit capital costs decrease from $10433/kWe to $7206/kWe, which is a decrease of 30%. From some point of view, the economics of scale is still important for the reactor design.

10. We can note from Figure 13 that generally the direct costs are larger than the indirect costs except for the PWR median experience (PWRM). It is also noted that the interest is generally larger than the direct and indirect costs, for an example, the interest of the PWRM is almost one and half times of the direct costs. However, the interest of the COAL plant is small compared with the direct costs and consequently results in a small capital costs.

11. The LMR reactors does better in the main conditioning heat rejection system, account 26, than the PWR. It is because the sodium has a larger thermal efficiency than the water.

TABLE 15. Sensitivity of capital cost (in $\$10^6$ of 2000 year dollars) on interest rate (relative to 11.35 %/year)

	Interest rate, %/year						
Account	9	10	11.35	12	13	14	15
Interest	-24.1%	-14.1%	1110	7.0%	18.1%	29.6%	41.5%
TOTAL	-8.5%	-5.0%	3130	2.5%	6.4%	10.5%	14.7%
$/kWe	9543	9913	10433	10693	11103	11529	11969

TABLE 16. Sensitivity of capital cost (in $\$10^6$ of 2000 year dollars) on lead time (relative to 8 years)

	Lead time, year						
Account	6	7	8	9	10	11	12
20	0.0%	0.0%	5	0.0%	0.0%	0.0%	0.0%
21	-3.7%	-2.1%	243	1.6%	3.7%	5.8%	7.8%
22	-4.5%	-2.4%	330	2.1%	4.2%	6.7%	8.8%
23	-3.8%	-2.3%	131	2.3%	4.6%	6.9%	9.2%
24	-4.3%	-2.2%	92	1.1%	3.3%	5.4%	7.6%
25	-2.5%	-1.3%	79	1.3%	3.8%	5.1%	7.6%
26	-4.2%	0.0%	24	4.2%	4.2%	8.3%	8.3%
Direct	-4.0%	-2.1%	904	1.9%	4.0%	6.2%	8.3%
91	-2.3%	-1.7%	177	1.1%	2.3%	3.4%	5.1%
92	-1.9%	-1.3%	313	0.6%	1.9%	2.9%	3.8%
93	-3.9%	-2.4%	127	1.6%	3.9%	5.5%	7.9%
94	-3.9%	-2.0%	152	1.3%	3.3%	4.6%	6.6%
Indirect	-2.7%	-1.7%	769	1.0%	2.5%	3.8%	5.2%
Contingency	-3.3%	-1.8%	333	1.5%	3.6%	5.1%	6.9%
Interest	-39.3%	-19.5%	1110	24.8%	50.0%	79.0%	111.2%
TOTAL	-16.1%	-8.1%	3130	9.7%	19.9%	31.9%	43.8%
$/kWe	8753	9586	10433	11449	12506	13699	15006

TABLE 17. Sensitivity of capital cost (in $\$10^6$ of 2000 year dollars) on escalation rate (relative to 5 %/year)

	Escalation rate, %/year						
Account	3	4	5	6	7	8	9
20	0.0%	0.0%	5	0.0%	0.0%	0.0%	0.0%
21	-16.0%	-8.2%	243	9.5%	19.3%	30.5%	42.0%
22	-17.0%	-8.8%	330	9.7%	20.0%	31.2%	43.6%
23	-16.8%	-8.4%	131	9.9%	19.8%	31.3%	43.5%
24	-16.3%	-8.7%	92	8.7%	19.6%	30.4%	41.3%
25	-15.2%	-7.6%	79	8.9%	19.0%	30.4%	41.8%
26	-16.7%	-8.3%	24	12.5%	20.8%	33.3%	45.8%
Direct	-16.4%	-8.4%	904	9.5%	19.6%	30.8%	42.6%
91	-14.7%	-7.9%	177	8.5%	17.5%	27.1%	37.9%
92	-14.4%	-7.3%	313	8.0%	16.6%	25.6%	35.5%
93	-16.5%	-8.7%	127	9.4%	19.7%	29.9%	41.7%
94	-15.8%	-8.6%	152	8.6%	18.4%	28.3%	40.1%
Indirect	-15.1%	-7.8%	769	8.5%	17.6%	27.3%	37.8%
Contingency	-15.9%	-8.1%	333	9.0%	18.9%	29.4%	40.8%
Interest	-14.6%	-7.6%	1110	8.1%	16.8%	26.3%	36.3%
TOTAL	-15.3%	-7.9%	3130	8.7%	18.0%	28.1%	38.8%
\$/kWe	8836	9609	10433	11336	12306	13359	14483

TABLE 18. Sensitivity of capital cost (in $\$10^6$ of 2000 year dollars) on power size (relative to 300 MWe)

	Power size, MWe			
Account	300	400	500	600
20	5	0.0%	0.0%	0.0%
21	243	15.6%	29.2%	41.6%
22	330	18.8%	35.8%	51.5%
23	131	26.0%	50.4%	74.0%
24	92	12.0%	22.8%	31.5%
25	79	8.9%	16.5%	24.1%
26	24	25.0%	50.0%	75.0%
Direct	904	17.5%	33.3%	48.0%
91	177	14.1%	26.0%	36.7%
92	313	6.1%	10.9%	15.0%
93	127	12.6%	22.8%	32.3%
94	152	15.1%	29.0%	40.8%
Indirect	769	10.7%	19.8%	28.0%
Contingency	333	14.4%	27.3%	39.0%
Interest	1110	13.4%	25.3%	36.1%
TOTAL	3130	14.0%	26.4%	37.7%
$/kWe	10433	8929	7928	7206

TABLE 19. Comparison of capital investment costs (not included initial charge of Na) for different types of electricity-generating facilities (relative to the TRENCH reactor)

Account	COAL	PWRB	TRENCH	LSPB	PWRM
20	0.0%	0.0%	5	0%	0.0%
21	-62.6%	-25.9%	243	0%	14.0%
22	-20.0%	-31.8%	330	53.9%	-14.8%
23	-19.1%	-5.3%	131	0%	15.3%
24	-40.2%	-13.0%	92	0%	30.4%
25	-57.0%	-35.4%	79	0%	0%
26	0.0%	12.5%	24	0%	33.3%
Direct	-36.0%	-23.5%	904	19.7%	4.5%
91	-71.8%	-19.8%	177	0%	46.9%
92	-90.1%	-24.6%	313	0%	72.8%
93	-80.3%	-18.9%	127	0%	220.5%
94	-55.3%	-25.0%	152	0%	29.6%
Indirect	-77.4%	-22.6%	769	0%	82.7%
Contingency	-66.4%	-24.0%	333	13.5%	38.4%
Interest	-74.0%	-23.2%	1110	9.0%	43.7%
TOTAL	-63.8%	-23.0%	3116	10.4%	41.4%
$/kWe	3847	7973	10387	11463	14687

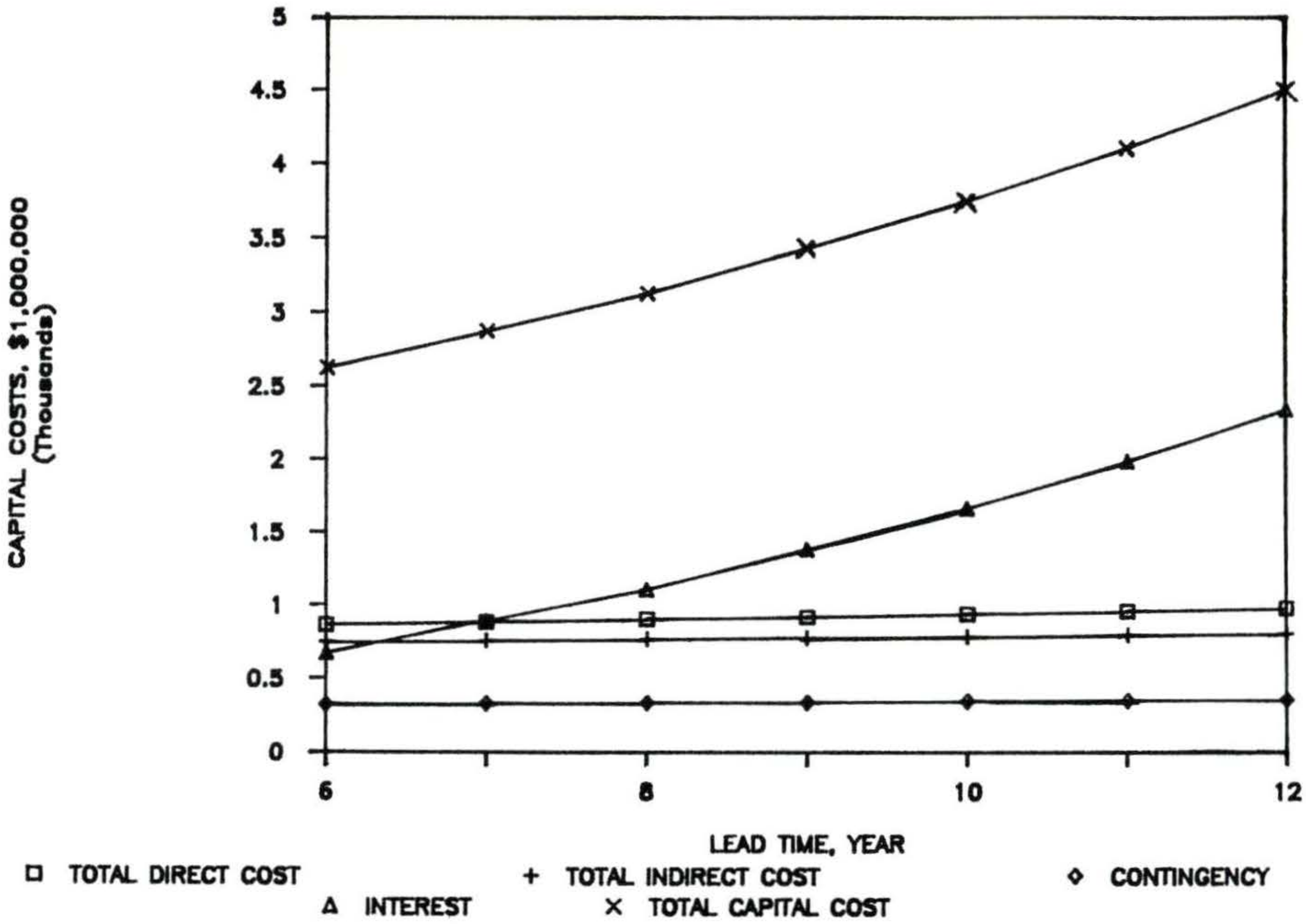


FIGURE 10. Sensitivity of capital costs on lead time, in $\$10^6$ of 2000 year dollars

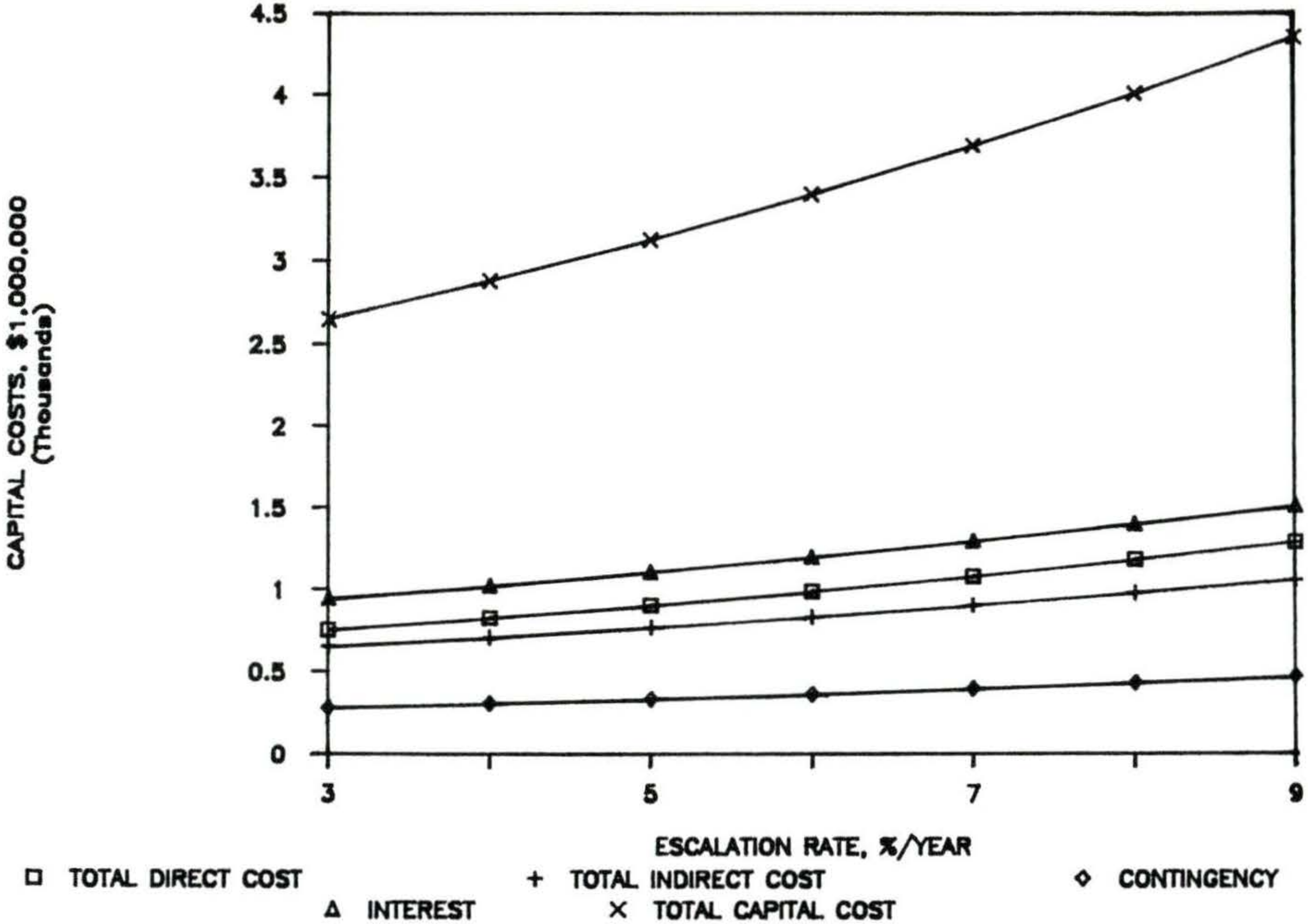


FIGURE 11. Sensitivity of capital costs on escalation rate, in $\$10^6$ of 2000 year dollars

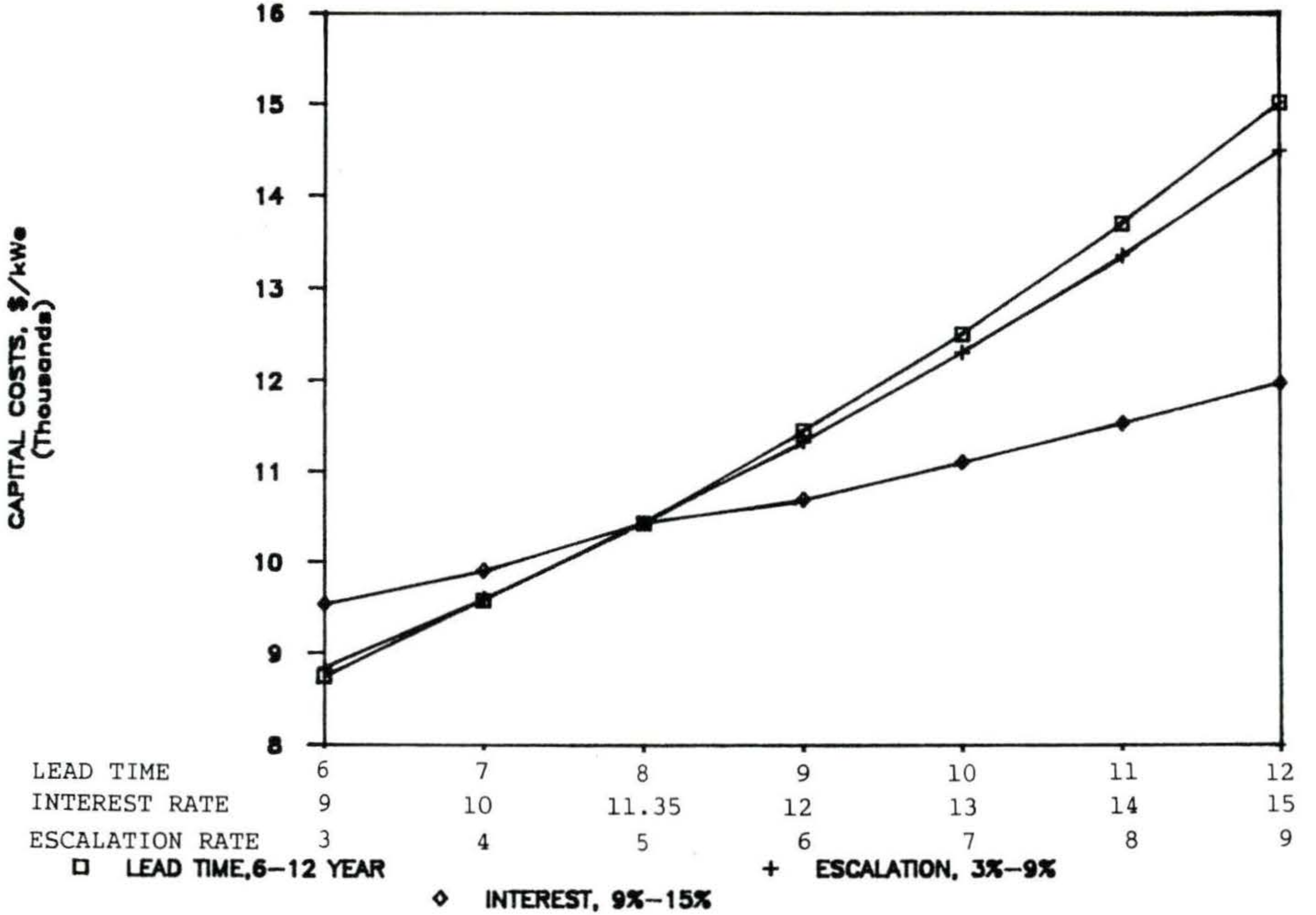


FIGURE 12. Comparison of sensitivity of total capital costs on lead time, escalation rate and interest rate, in $/kWe of 2000 year dollars

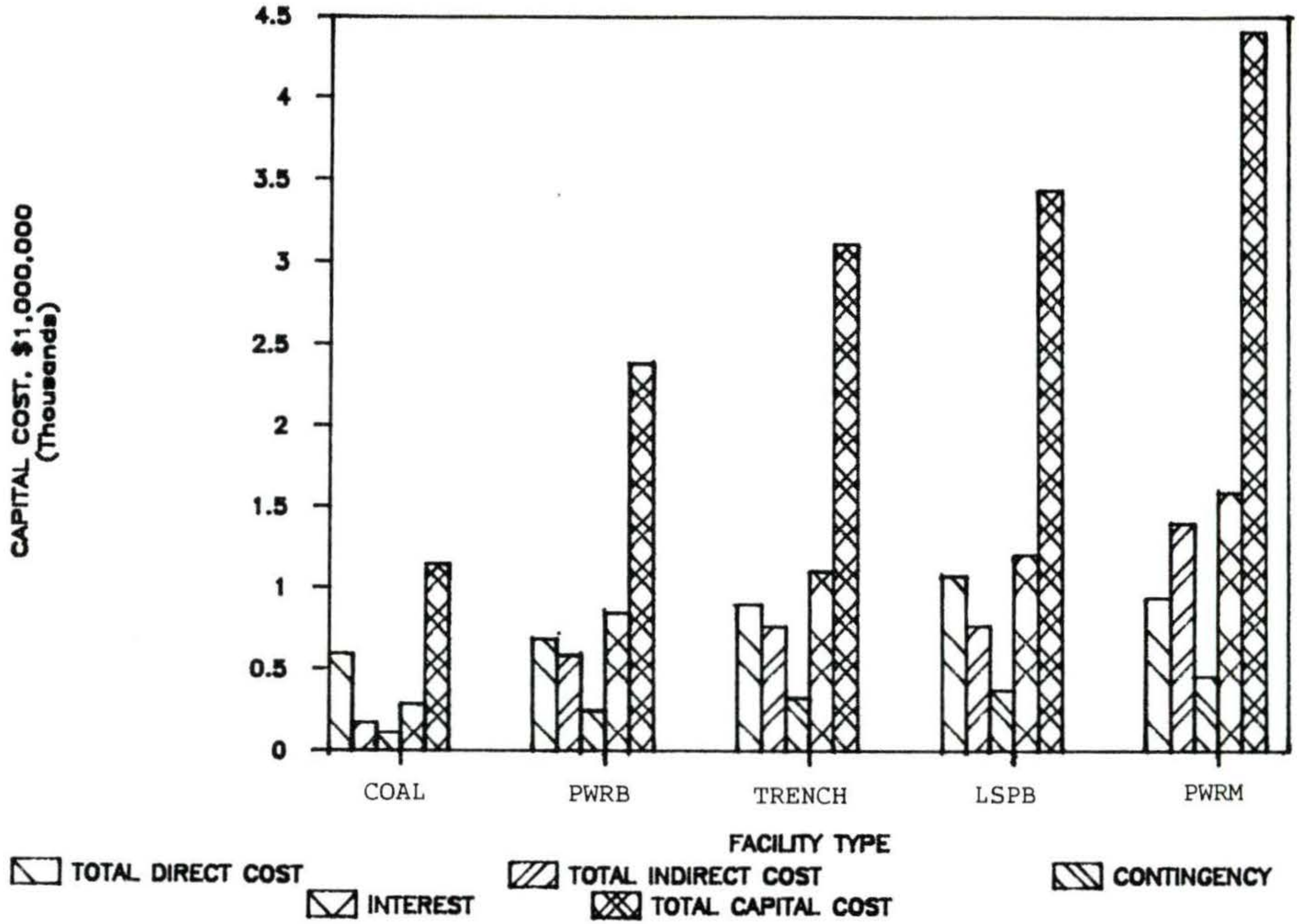


FIGURE 13. Comparison of capital costs for different types of electricity-generating facilities, in $\$10^6$ of 2000 year dollars

4. FUEL COSTS CALCULATION

The nuclear fuel costs are composed of many separate subcosts, which are related to the various fuel cycle materials, service requirements, and credits received for residual fuel materials. The cash payments related to these fuel subcosts occur at different times relative to power production. Fuel is loaded and unloaded in batches, each batch having different cash flow requirements caused by both composition differences from batch to batch and changes in the prices of fuel commodities and services.

To estimate the fuel costs, we use discounted cash flow (DCF) techniques, which is implemented in the REFCO computer code [25], to show the logical formulation of the levelized fuel cycle cost equation. Then we use a simplified version of the REFCO computer code, NFUEL [8], to calculate the fuel cycle cost.

4.1 Methodology

4.1.1 Discounted cash flow method

The DCF analysis establishes a fuel cost by requiring that the revenues from the sale of energy be adequate to pay the required return on outstanding capital, to pay all expenses including taxes, and to retire the outstanding investment to zero by the end of the economic life of the set of fuel investments. The DCF procedure is applied on a batchwise basis for each cost component, that is, levelized fuel subcosts are calculated for each discrete batch of fuel elements loaded into the reactor. A fuel batch is defined as a set of fuel elements with a specific charge and discharge time and with the same fuel composition at the time of charge.

Although the DCF method enters cash receipts and expenditures at the actual time they occur, we can develop the basic theory in discrete time periods and adjustments will be made to account for the continuity of cash payments and revenues received.

Assuming equal time periods, capitalized investments are made at the beginning of the time periods, and revenues and operating costs are transacted at the end of the time periods.

At the start of the first time period the capital outstanding is equal to the initial investment.

$$V_1 = I_o$$

From eq. (6) the income taxes paid at the end of the first period are

$$T_1 = t(R_1 - O_1 - D_1^T - I_o Bb) \tag{43}$$

At the end of first period the funds available to pay back the outstanding capital, from eq. (20), is

$$C_1 = R_1 - O_1 - I_o(Bb + eE + pF) - T_1 \tag{44}$$

Substituting T_1 from eq. (43) into eq. (44), one has

$$C_1 = (1-t)(R_1-O_1) - I_o[eE+pF+(1 - t)Bb] + tD_1^T \tag{45}$$

In the second period,

$$V_2 = (V_1 - C_1) + I_1 \tag{46}$$

Substituting C_1 from eq. (45) into eq. (46), one has

$$V_2 = I_o[1 + eE + pF + (1 - t)Bb] + I_1$$
$$+ (1 - t)O_1 - tD_1^T - (1 - t)R_1$$

Since, from eq. (18), $X = eE + pF + (1-t)bB$,

$$V_2 = (1 + X)I_o + I_1 + (1 - t)O_1 - tD_1^T - (1 - t)R_1 \tag{47}$$

Also

$$T_2 = t(R_2 - O_2 - V_2Bb - D_2^T)$$

and

$$C_2 = R_2 - O_2 - V_2(Bb + pF + eE) - T_2$$
$$= R_2 - O_2 - V_2(Bb + pF + eE) - t(R_2-O_2-V_2Bb-D_2^T)$$
$$= (R_2 - O_2)(1 - t) + tD_2^T - V_2X$$

Using the same manner in the third period,

$$V_3 = V_2 - C_2 + I_2$$
$$= (1 + X)V_2 + I_2 + (1 - t)O_2 - tD_2^T - (1 - t)R_2 \tag{48}$$

Substituting V_2 from eq. (47) into eq. (48), one has

$$V_3 = I_o(1 + X)^2 + I_1(1+X) + I_2 + (1-t)[(1 + X)O_1 + O_2]$$
$$-t[(1 + X)D_1^T + D_2^T] - (1 - t)[(1 + X)R_1 + R_2]$$

Continuing this procedure through N-1 periods, we will get

$$V_N = \sum_{n=0}^{N-1} I_n(1 + X)^{N-n-1} + (1 - t) \sum_{n=1}^{N-1} O_n(1 + X)^{N-n-1}$$

$$- t \sum_{n=1}^{N-1} D_n^T(1 + X)^{N-n-1} - (1-t) \sum_{n=1}^{N-1} R_n(1 + X)^{N-n-1}$$

At the end of the Nth period the project is over so that the rate base must be zero, i.e., $V_{N+1} = 0$, and

$$\sum_{n=0}^{N} I_n(1 + X)^{N-n} + (1 - t) \sum_{n=1}^{N} O_n(1 + X)^{N-n}$$

$$- t \sum_{n=1}^{N} D_n^T(1 + X)^{N-n} - (1 - t) \sum_{n=1}^{N} R_n(1 + X)^{N-n} = 0$$

Divide by $(1 - t)(1 + X)^N$ to get the PWRR for nuclear fuel,

$$\begin{aligned} \text{PWRR} = \sum_{n=1}^{N} \frac{R_n}{(1 + X)^n} &= \frac{1}{1 - t} \sum_{n=0}^{N} \frac{I_n}{(1 + X)^n} \\ &+ \sum_{n=1}^{N} \frac{O_n}{(1 + X)^n} - \frac{t}{1 - t} \sum_{n=1}^{N} \frac{D_n^T}{(1 + X)^n} \end{aligned} \tag{49}$$

Substituting R_n from eq. (16) into eq. (49), we can get the levelized price $\overline{P}$ in nominal dollars.

$$\overline{P} = \frac{\dfrac{1}{1-t} \displaystyle\sum_{n=0}^{N} \frac{I_n}{(1 + X)^n} - \frac{t}{1-t} \sum_{n=1}^{N} \frac{D_n^T}{(1 + X)^n} + \sum_{n=1}^{N} \frac{O_n}{(1 + X)^n}}{\displaystyle\sum_{n=1}^{N} \frac{S_n}{(1 + X)^n}} \tag{50}$$

Equation (50) is for payments and receipts made at the boundary of equal time intervals. A more general relation is one in which cash transactions can be made at any time t relative to reactor startup. Then eq. (50) becomes

$$\overline{P} = \frac{\frac{1}{1-t} \sum_{time} \frac{I_t}{(1+X)^t} - \frac{t}{1-t} \sum_{time} \frac{D_t^T}{(1+X)^t} + \sum_{time} \frac{O_t}{(1+X)^t}}{\sum_{time} \frac{S_t}{(1+X)^t}}$$

Although the purchases of the fuel cycle materials and services occur at discrete times, the sale of power occurs more or less continuously. Therefore, it becomes easier to represent the fuel cycle cost equation in its exponential form.

$$\overline{P} = \frac{\frac{1}{1-t} \int I_t e^{-Yt} dt - \frac{t}{1-t} \int D_t^T e^{-Yt} dt + \int O_t e^{-Yt} dt}{\int S_t e^{-Yt} dt} \qquad (51)$$

where

- $Y = \ln(1 + X)$

  = equivalent interest rate for continuous discounting

Note that the capitalized investment, I_t, the expensed operating costs, O_t (other than waste disposal), and the revenues from the energy production are paid at discrete refueling periods plus or minus a lag or lead time. However, energy is produced continuously. The revenues from the energy sale will usually lag production. Therefore, the integral in the denominator becomes

$$\int_{t_i+SLG}^{t_o+SLG} S_t e^{-Yt} dt$$

where

- t_o = time fuel is removed from core
- t_i = time fuel enters core
- SLG = 0.5 year

  = lag time for revenue collection

In addition, the tax depreciation term, D_t^T, and waste fund payment (expensed and included in O_t) are treated as continuous functions since they are related to revenues received and power production.

The total levelized cost for a fuel batch, $\overline{P}_B$, is the sum of the component levelized costs, $\overline{P}_{jB}$, for the particular batch, B.

$$\overline{P}_B = \sum_j \overline{P}_{jB}$$

The lifetime levelized cost is the cumulative batch levelized cost over the reactor life. It is obtained by summing the numerator and denominator of eq. (51) separately and then taking the ratio of the resulting sums.

$$a = \sum_{B} \sum_{J} [\frac{1}{1-t} \int I_t e^{-Yt} dt - \frac{t}{1-t} \int D_t^T e^{-Yt} dt + \int O_t e^{-Yt} dt]$$

$$\beta = \sum_{B} [\int S_t e^{-Yt} dt]$$

$$\overline{P} = \frac{a}{\beta} \tag{52}$$

Cycle levelized costs can also be calculated. A cycle is the period of time between refuelings and is composed of several batches in various stages of irradiation. The levelized fuel cost, $\overline{P}_C$, for any cycle, C, is

$$\overline{P}_C = \frac{\sum_{B \epsilon C} \int e^{-Yt} \, \overline{P}_B \, S_{BC} \, dt}{\sum_{B \epsilon C} \int e^{-Yt} \, S_{BC} \, dt}$$

where

- S_{BC} = energy generated by batch B during cycle C
- $B \epsilon C$ = the sum over all batches B contained in cycle C

4.1.2 Waste disposal cost

The Nuclear Waste Policy Act of 1982 provides for the collection of a fee from utilities as nuclear electricity is produced. This fee is set to be 1 mill/kWh. In the NFUEL program, a base price and escalation rate for this cost may be specified.

The cash flow for waste disposal is assumed to be continuous. The lag time is the same as that for electric sales revenues, i.e., 0.5 year. In addition the waste disposal unit cost (mill/kWh) is assumed to change continuously with escalation rate.

The operating cost term for the waste disposal cost in eq. (51) becomes

$$\int O_t e^{-Yt} dt = \int_{t_i+SLG}^{t_o+SLG} P_w S_t e^{-Y_w t} dt$$

where

- P_w = the reference price for waste disposal at reactor startup
- $Y_w = \ln(1 + X) - \ln(1 + e_w)$
- e_w = escalation rate for waste disposal price, including inflation

4.2 Calculation Procedures and Results

4.2.1 Tax depreciation options

There are two tax depreciation options. One is to depreciate the fuel in a given period proportional to the energy produced. The other is a 5-year ACRS depreciation procedure. The 5-year ACRS depreciation procedure is simpler to use and produces a lower cost than the other option. Therefore, it is adopted by the NFUEL program to depreciate the fuel investments using the 5-year ACRS depreciation percentages, regardless of actual fuel life. The present worth of 5-year ACRS depreciation is [8]

$$PWDP = e^{(-SLG)Y} \left[\sum_{k=1}^{5} \frac{D(k)[\ e^{-(k-1)Y} - e^{-kY}]}{Y} \right] \tag{53}$$

where

- $D(k)$ = recovery percentages of 5-year ACRS depreciation as shown in Table 2 in Chapter 1.

4.2.2 Capitalized and expensed payments

The fuel payments can be either capitalized or expensed. If they are capitalized, the tax deduction is spread over the life of the fuel in the reactor. If the payment is expensed, the tax deduction is taken immediately or with a set lag time.

Generally, all costs associated with the charged fuel (front end costs) such as purchase, conversion, enrichment, and fabrication are capitalized. The present worth of revenue requirements of the capitalized payments is [8]

$$PWRR = VALUE_{Bj}\ e^{-Yt_i} \left[\frac{e^{YB} - i(PWDP)}{1 - i}\right] \tag{54}$$

where

- $VALUE_{Bj}$ = cost of fuel component j in batch B
- B = lead or lag time for component j in batch B as shown in Table 23, positive means lead time
- i = income tax rate

The costs associated with the discharged fuel (back end costs), except recycled plutonium and waste disposal cost, are generally expensed. The PWRR of the expensed payments is [8]

$$PWRR = VALUE_{Bj}\, e^{-Y(t_o-B)} \tag{55}$$

There are three treatment options for recycled plutonium.

1. Capitalize all charges, expense all discharges: all plutonium charged to the reactor is capitalized and depreciated as 5-year ACRS depreciation. All plutonium discharged from the reactor is assumed to be sold, and the money received is treated as current income (reverse expense) for tax purposes.

2. Capitalize net recycle, expense net discharge: recycled plutonium is assumed to have a zero tax depreciation basis since it was fully depreciated in the previous cycle. The net plutonium needed in addition to recycle is capitalized and depreciated for tax purposes. Any excess plutonium produced over recycle requirements is sold for current income.

3. Capitalize reprocessing costs into recycle plutonium: the cost of reprocessing to recover plutonium is capitalized into the value of the recovered plutonium. This cost and the cost of any make-up plutonium are depreciated as specified. Excess plutonium is sold for current income and the cost of its recovery is expensed.

The plutonium in spent fuel is effectively worthless as far as its ability to be used in that form. Reprocessing is a process that enhances the value of the asset plutonium, much like enrichment enhances the value of uranium. Therefore, the reprocessing cost should be capitalized into the cost basis of the recovered plutonium. If the plutonium is recycled, this cost is depreciated over the new fuel's tax life. If the plutonium is sold, the cost of recovering this plutonium is expensed and the net of sale price over cost basis is income. Therefore, we choose option 3.

The waste disposal cost is expensed as a fee which is proportional to the amount of electricity sold. Its present worth of revenue requirements is [8]

$$PWRR=P_W S_B (1+e_W)^{(T_c-T_r)} \frac{[e^{-Y_W(t_i+SLG)}][1-e^{-Y_W DT}]}{Y_W} \tag{56}$$

where

- S_B = energy produced by batch B
- DT = the period of time fuel batch B remains in the core
- T_c = year of first commercial operation
- T_r = reference year

The present worth of energy produced by a batch B is [26]

$$CUMS = S_B \frac{[1 - e^{-Y(DT)}]\ e^{-Y(t_i+SLG)}}{Y(DT)}$$

Then, from eq. (52), we can sum the PWRR in eq. (54), eq. (55), eq. (56) and CUMS over all batches in the reactor to get α and β respectively, and the levelized fuel cost would be the ratio of α and β.

4.2.3 Capacity factor adjustments

The input mass flow data used by NFUEL are prepared for specified cycle times at a specified capacity factor. Since the NFUEL program is for a default annual reloading, we can not specify a ten-year cycle with a 70% capacity factor directly in the input data. We must specify a one-year cycle with a 700% capacity factor and convert it to the desired case [27]. That is, the fuel component weights in the reference flow data are obtained from a ten-year cycle calculation, but the capacity factor and cycle time in the reference flow data must be changed to 700% and one year, respectively.

The adjustments to our specified capacity factor, 0.7, and ten-year cycle are made by keeping the fuel burnup in the individual batches constant. It is made by changing the individual cycle times. Then equilibrium fuel batches will be added or subtracted from the mass flow to maintain the approximate reactor life as specified. For our specified capacity factor 70% the adjustment factor would be 700%/70%, i.e., 10. This adjustment factor would lengthen the cycle time from one year to ten years, which is our desired cycle time.

4.2.4 Results

We have demonstrated the methodologies used in the NFUEL program in the preceding sections. Now we can use NFUEL to estimate the fuel cost for the TRENCH reactor. For the ten-year cycle, the mass balance data are shown in Table 20. The input data and the reference prices

TABLE 20. Reference mass flow data for ten-year cycle

Component	Core	Lateral blanket	Axial blanket
Total U load, kg	32110.7	1555.46	6191.65
Total U-235 load, kg	64.2	3.89	15.5
Fissile Pu load, kg	2892.2	0	0
Total U discharge, kg	29415	1436.488	6061.68
Total U-235 discharge, kg	32.7	2.08	13.1
Fissile Pu discharge, kg	3011.2	76.25	104.02
Total heavy metal load, kg	35964.8	1555.46	6191.65
Total heavy metal discharge, kg	33410.9	1516.52	6167.5
Number of batches	1	1	1
Capacity factor, fraction	7	7	7
Average number of cycles a batch remains in core	1	1	1
Plant life, years	30	30	30
Unit power rating, Mwe	300	300	300

used are shown in Tables 21 and 22 respectively. Default values used in the NFUEL program are shown in Tables 23 and 24. Finally, the fuel costs for the ten-year cycle are shown in Tables 25 and 26.

We can calculate the fuel cost with different tax depreciation procedures and recycled plutonium treatments to demonstrate the effects of alternate options on the fuel costs while leaving other input parameters unchanged. The results are summarized in Table 27. The values in the parentheses of Table 27 are in constant dollars and others are in nominal dollars. We can conclude from the results above that

1. It is more economic to depreciate fuel investments by using the 5-year ACRS depreciation method than that of proportional to energy produced.

2. Among the three options of recycled plutonium treatment, option 2, capitalize net recycle and expense net discharge, is the most economic even though we choose option 3. The difference between option 2 and 3 is that option 3 transfers the plutonium reprocessing cost into the plutonium purchase price and capitalizes the reprocessing cost, which causes a larger increase in plutonium purchase price than the offset in plutonium reprocessing cost.

Next we will calculate the effects of startup year, inflation rate, and escalation rate on the fuel costs. The results are summarized in Tables 28, 29 and 30. They are used to construct the curves as shown in Figures 14 and 15. The two common points in Figure 15 are for our reference case whose results are shown in Tables 25 and 26.

It is noted from the results above that

1. Since we assume there is no real escalation in excess of inflation for fuel costs, the fuel costs in constant dollars do not change when the startup year delays. Its curve is horizontal as seen from Figure 14. However, the fuel costs in nominal dollars increase when the startup year delays.

2. The two curves for escalation rate in Figure 15 show different increasing rates. The curve for the nominal dollar cost has a larger increasing rate than that for constant dollar cost. However, the curve for constant dollar cost is more realistic and understandable because it removes the inflation from the results and is related with the present day conditions.

3. From Figure 15, the fuel costs in nominal dollar keep the same value when the inflation rate increases, while the constant dollar cost decreases. This is consistent with the prediction of eq. (29).

4. It can be seen from comparing the slopes of Figures 14 and 15 that the effects of a 1% increase in escalation rate on fuel costs is stricter than that of one year delay in startup year.

TABLE 21. Data base for fuel cost calculation

Component	Value
Plant startup year	2000
Capacity factor	0.7
Revenue lag time (year)	0.5
General inflation rate, %/year	5
Real escalation rate in excess of inflation rate, %/year	0
Effective cost of money	0.0957
Income tax rate	0.3664
Reference year for cost data	1986
Enrichment plant tails assay	0.2 %
Fuel recycle turnaround time, year	2

TABLE 22. Fuel cycle cost component price in reference year dollars [8 and 28]

Cost Component		Core	Lateral Blanket	Axial Blanket
Plutonium	($/gm)	25.00	25.00	25.00
Fabrication	($/kg)	300.00	300.00	300.00
Reprocessing	($/kg)	670.00	670.00	670.00
Waste Disposal	(mill/kWh)	1.00	0.00	0.00

TABLE 23. Fuel cycle lead and lag times (year)

Component	Initial Core	Recycle load
Plutonium purchase	2.0	1.0
Fabrication	0.75	0.5
Plutonium sales	-1.0	-1.0
Reprocessing	-1.0	-1.0
Waste disposal	0.0	0.0

TABLE 24. Fissile material losses

Component	%
Conversion	0.5
Uranium fabrication	1
Plutonium fabrication	1
Uranium reprocessing	1
Plutonium reprocessing	1

TABLE 25. Nuclear fuel costs (mills/kWh) for ten-year cycle in nominal dollars

Cost Component	Core	Lateral Blanket	Axial Blanket	Total Cost
Uranium purchase	0.000	0.000	0.000	0.000
Conversion purchase	0.000	0.000	0.000	0.000
Enrichment purchase	0.000	0.000	0.000	0.000
Plutonium purchase	13.988	0.000	0.000	13.988
Fabrication	2.912	0.126	0.501	3.539
Uranium credit	0.000	0.000	0.000	0.000
Conversion credit	0.000	0.000	0.000	0.000
Enrichment credit	0.000	0.000	0.000	0.000
Plutonium Sales	-2.359	-0.270	-0.369	-2.998
Reprocessing	0.709	0.146	0.592	1.447
Waste disposal	3.356	0.000	0.000	3.356
	------	------	------	------
Total	18.605	0.001	0.725	19.331

TABLE 26. Nuclear fuel costs (mills/kWh) for ten-year cycle in constant dollars

Cost Component	Core	Lateral Blanket	Axial Blanket	Total Cost
Uranium purchase	0.000	0.000	0.000	0.000
Conversion purchase	0.000	0.000	0.000	0.000
Enrichment purchase	0.000	0.000	0.000	0.000
Plutonium purchase	4.167	0.000	0.000	4.167
Fabrication	0.868	0.038	0.149	1.055
Uranium credit	0.000	0.000	0.000	0.000
Conversion credit	0.000	0.000	0.000	0.000
Enrichment credit	0.000	0.000	0.000	0.000
Plutonium sales	-0.703	-0.081	-0.110	-0.894
Reprocessing	0.211	0.043	0.176	0.43
Waste disposal	1.000	0.000	0.000	1.000
	------	------	------	------
Total	5.542	0.000	0.216	5.758

TABLE 27. Cost comparisons between different options of tax depreciation and recycled plutonium treatments

Recycle plutonium treatment	Tax depreciation procedure: Units of production	5-year ACRS
1	22.27 (6.633)	20.559 (6.124)
2	19.286 (5.744)	18.341 (5.463)
3	20.53 (6.115)	19.331 (5.758)

TABLE 28. Sensitivity of startup year on the ten-year cycle fuel costs (mills/kWh)

Startup year	Nominal dollar	Constant dollar
2000	19.331	5.758
2001	20.298	5.758
2002	21.313	5.758
2003	22.378	5.758
2004	23.497	5.758
2005	24.673	5.758
2006	25.906	5.758

TABLE 29. Sensitivity of inflation rate (%/year) on the ten-year cycle fuel costs (mills/kWh)

Inflation rate	Nominal dollar	Constant dollar
2	19.331	12.035
3	19.331	9.448
4	19.331	7.389
5	19.331	5.758
6	19.331	4.470
7	19.331	3.456
8	19.331	2.662

TABLE 30. Sensitivity of escalation rate (%/year) on the ten-year cycle fuel costs (mills/kWh)

Escalation rate	Nominal dollar	Constant dollar
2	12.115	3.608
3	14.141	4.212
4	16.525	4.923
5	19.331	5.758
6	22.627	6.739
7	26.481	7.888
8	30.961	9.222

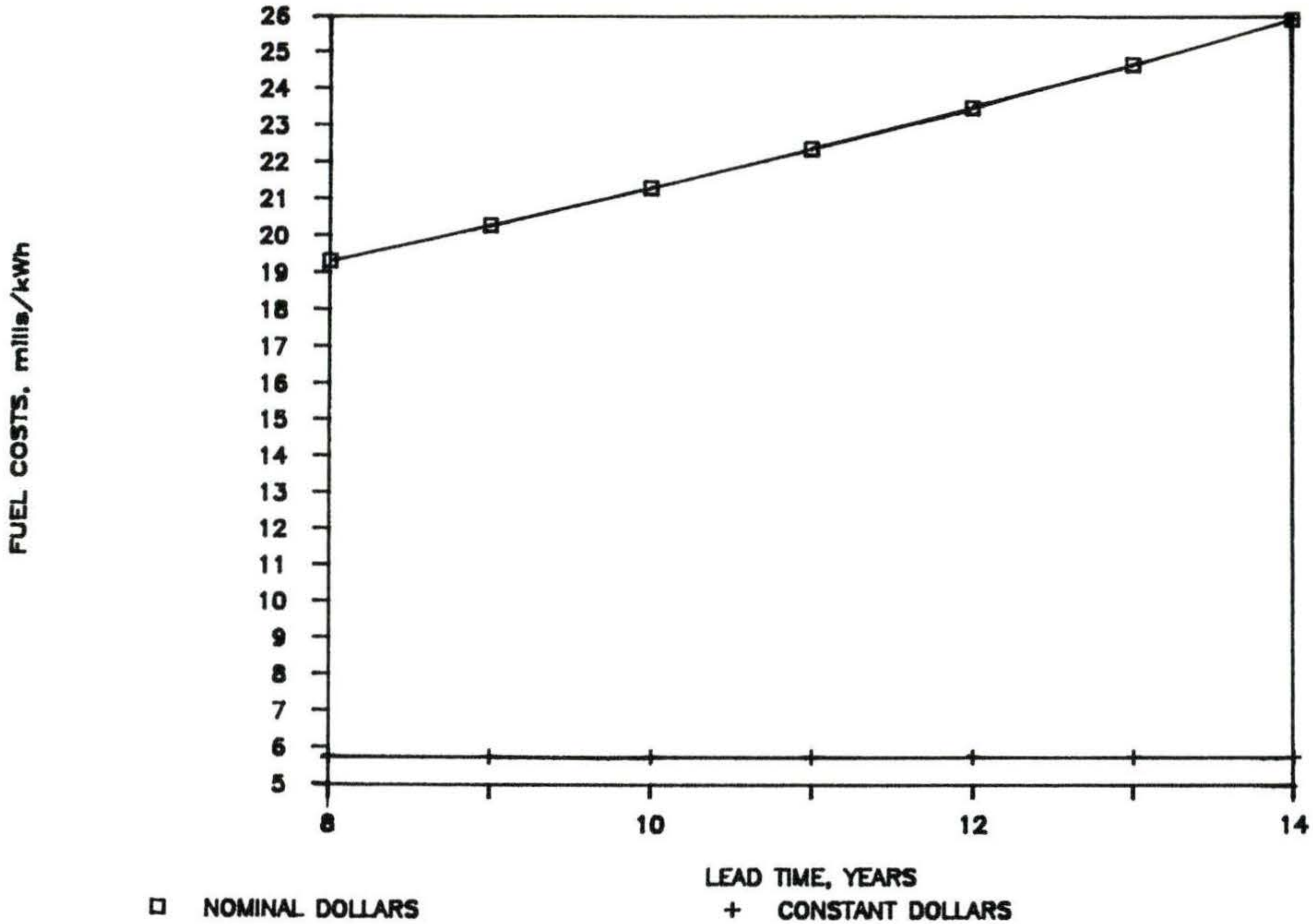


FIGURE 14. Sensitivity of lead time on ten-year cycle fuel costs (mills/kWh)

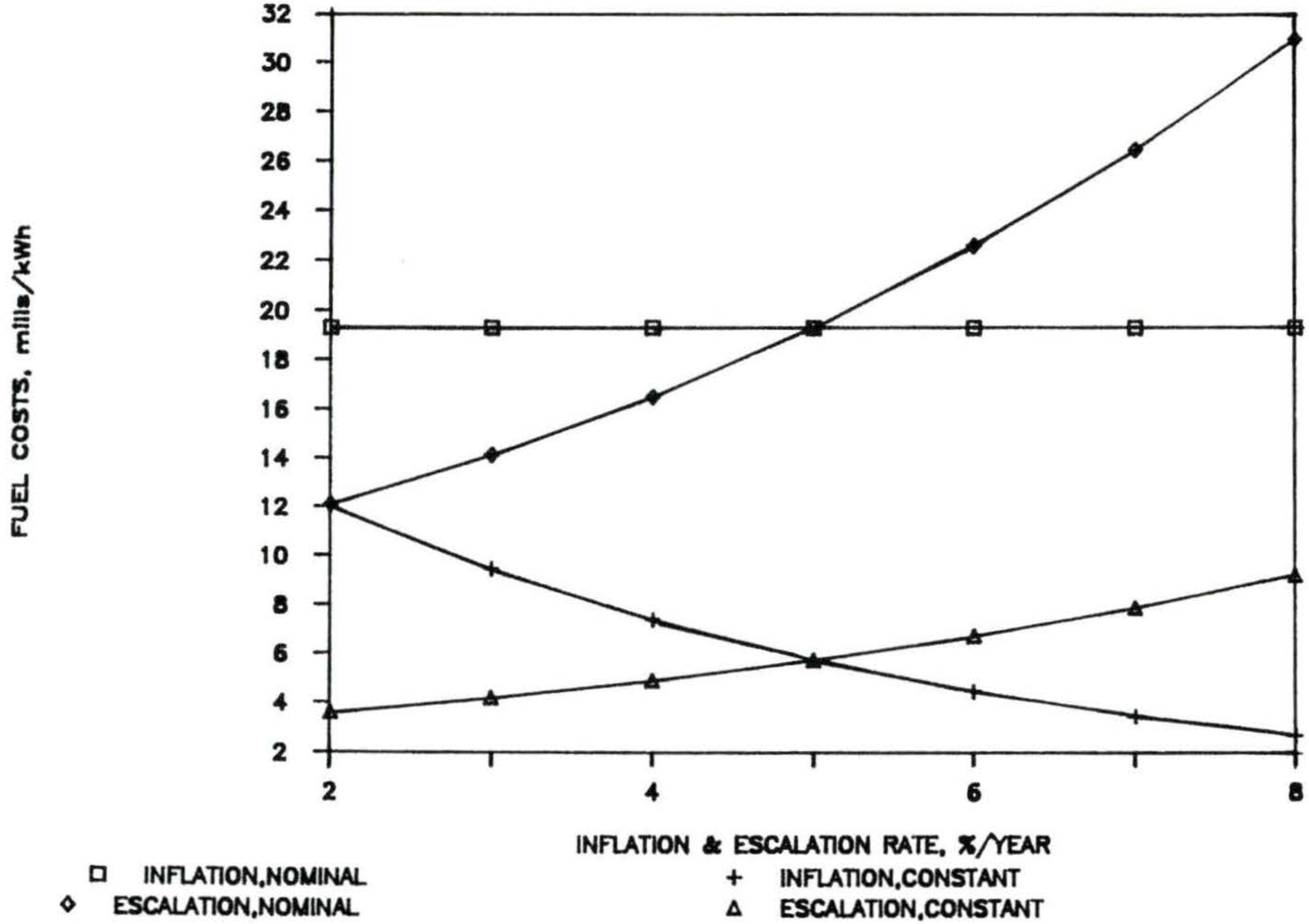


FIGURE 15. Sensitivity of inflation rate and escalation rate (%/year) on ten-year cycle fuel costs (mills/kWh)

5. OTHER COST CALCULATIONS

To complete the estimates of power generation costs, the calculation processes of operation and maintenance costs and decommissioning costs are analyzed in this Chapter.

The O&M costs of nuclear power plants have risen dramatically because of increases in onsite staffing requirements, offsite support services, insurance costs, and administrative and general expenses since the time of occurrence of Three-Mile-Island accident. Insurance costs and other administrative and general expenses are not traditionally included in the O&M costs.

The cost-estimating procedures of O&M costs involve the application of some empirical functions, which are shown in Section 5.1.2, that represent historical experience plus new factors arising from regulatory, operating, and economic considerations.

5.1 Operation and Maintenance Costs

5.1.1 Methodology

Operation and maintenance costs include all costs (other than fuel costs) that are expended to operate and maintain the plant. They usually include two parts: fixed costs, which are independent of plant capacity factor, and variable costs, which are directly proportional to capacity factor. Therefore the annual O&M costs are

OM = (variable cost)(plant capacity factor)

$$+ \text{ fixed cost} \tag{57}$$

The present worth of the O&M revenue requirements discounted to the start of plant operation is

$$PWRR_{OM} = \sum_{n=1}^{N} \frac{(OM)_n}{(1 + X)^n}$$

which may be substituted into eq. (23) and eq. (26) to get $\overline{P}_{OM}$ and $\overline{P}_{oOM}$ respectively.

If the rate of cost escalation in the O&M costs is g, then the constant dollar levelized O&M costs is given by

$$\overline{P}_{oOM} = (OM)_o \ (DEF)_o \tag{58}$$

where

- $(OM)_o$ = reference year's O&M costs
- DEF = differential escalation factor, which converts a series of costs which increases at a compound rate, g, into an equivalent series of costs increasing at a second compound rate, a.

$$DEF = \frac{CRF[(\frac{X - a}{1 + a}), N]}{CRF[(\frac{X - g}{1 + g}), N]} \left(\frac{1 + a}{1 + g}\right)^{-L} \tag{59}$$

then from eq. (27) and eq. (59)

$$DEF = \left[\left(\frac{1 + g}{1 + a}\right)^{L+1}\right] \left(\frac{X - a}{X - g}\right) \left[\frac{(1 + X)^N - (1 + g)^N}{(1 + X)^N - (1 + a)^N}\right] \tag{60}$$

For the constant dollar case the equivalent series increases at the rate of inflation, i, so

$$a = i$$

then from eq. (19), eq. (59) and $(1 + g) = (1 + r)(1 + i)$

$$(DEF)_o = (1 + r)^L \frac{CRF(X_o, N)}{CRF[(\frac{X_o - r}{1 + r}), N]} \tag{61}$$

For the nominal dollar case, the equivalent series remains constant in nominal dollars, so

$$a = 0$$

then from eq. (59),

$$DEF = \frac{CRF(X, N)}{CRF[(\frac{X - g}{1 + g}), N]} (1 + g)^L \tag{62}$$

and

$$\bar{P}_{OM} = (OM)_o(DEF) \tag{63}$$

If it is assumed that the cost escalation rate, g, is the same as the general inflation rate, i.e., no real escalation for O&M costs, then $r = 0$ and from eq. (61),

$$(DEF)_o = 1.0$$

Since the assumption of the reference case is that the rate of price escalation is equal to the inflation rate, i.e., $g = i$, so, from eq. (58), the constant dollar power generation costs from O&M is

$$\overline{P}_{oOM} = (OM)_o$$

5.1.2 Calculation procedures and results

To calculate the O&M costs for the TRENCH reactor, we use the procedures adopted by OMCOST code [29], which is a mainframe computer code to calculate O&M costs, and uses a simplified version of the OMCOST code, LMROM [8], to estimate the O&M costs for the TRENCH reactor. The LMROM code is basically the same as the code for calculating the O&M costs for a PWR except that it is assumed that the maintenance materials and supplies of the LMR are 50% and 15% more than those of PWR respectively [8]. The 50% and 15% values come from the ratios of the maintenance materials and supplies of the Clinch River Breeder Reactor to LWR [9].

The calculation of O&M costs involves many default values and empirical functions which are summarized in Table 33. The symbols in Table 33 are those used in the LMROM code. Some of these default values and empirical functions are discussed below.

The insurance costs included in the O&M costs include premiums for property damage insurance, nuclear liability insurance, and replacement power insurance. The relation between these insurance costs, inspection fees and unit numbers used in the LMROM code is shown in Table 31. Other administrative and general expenses are for utility company overhead costs that are not chargeable to the direct O&M cost accounts and are assumed to be 15% of the sum of the direct costs listed in Table 34.

TABLE 31. Relation between some cost components and unit numbers, in $\$10^6$/year of 1986 dollars [8 and 29]

Cost component	One unit	Each additional unit
Property fees, Inspection and Review expenses	1.04	0.520
Nuclear liability insurance	0.52	0.208
Retrospective premium	0.0104	0.0104
Primary property damage insurance	P[a]	0.82P
Excess property damage insurance	Q[b]	0.14Q
Replacement power insurance	1.4	1.4

[a] P = (property insurance rate) · (property insurance coverage).

[b] Q = 0.6 P.

The staff requirements for a nuclear power plant adopted by the LMROM code are for plant sizes ranging from 800 to 1200 MWe. Since the TRENCH reactor is only 300 MWe, the staff requirements should be less. There are some differences for staff requirements for a nuclear plant between 400 MWe and 800 MWe [30]. Therefore, we can get a ratio of staff requirements for plant sizes of 400 and 800 MWe, and multiply the original staff requirements in the LMROM code by this ratio to get the staff requirements for the TRENCH reactor as shown in Table 32. Finally, we substitute these values into the LMROM code and get the O&M costs for the TRENCH reactor as shown in Table 34. The characters after the costs in Table 34 are used to demonstrate the calculation processes, and all the equations below, including empirical equations, are those used to obtain the costs in Table 34.

- $X1 = S(U) \times M3 / 10^6$
- $X2F = F2 \times B3$
- $X2V = V1 \times B3 \times P / B1$
- $X2 = X2F + X2V$
- $X3F = S5 \times U \times (1 + E4)^{Y-B2} / 1000$
- $X3V = V5 \times A \times (1 + E4)^{Y-B2} / 1000$
- $X3 = X3F + X3V$
- $X4 = (520 + 520 \times U) \times (1 + E5)^{Y-B2} / 1000$
- $X5 = S4(U) \times M3 \times R2 / 1{,}000{,}000$
- $AG1 = (312 + 208 \times U) \times (1 + E1)^{Y-B2} / 1000$
- $AG2 = 10.4 \times U \times (1 + E1)^{Y-B2} / 1000$
- $AG3 = [(0.18+0.82xU)xP5xC3/100]x(1+E2)^{Y-B2}/1000$
- $AG4 = [(0.86+0.14xU)x0.6xP5xC3/100]x(1+E2)^{Y-B2}/1000$
- $AG5 = 1.4 \times U \times (1 + E3)^{Y-B2}$
- $D = X1 + X2 + X3 + X4 + X5$
- $AG6 = 0.15 \times D$
- $AG = AG1 + AG2 + AG3 + AG4 + AG5 + AG6$
- $TF = X1 + X2F + X3F + X4 + X5 + AG$

- TV = X2V + X3V
- T = TF + TV
- UF = 1000 x TF / A
- UV = 1000 x TV / A
- UT = UF + UV

To show the effects of power size, unit number and base capacity factor on the O&M costs, we calculate the O&M costs with a different power size, unit number and base capacity factor while leaving other input parameters unchanged. The results are summarized in Tables 35, 36, and 37. Note that the $/year and mills/kWh values in Tables 35, 36, and 37 are from T and UT in Table 34, respectively.

To show the trends of O&M costs with these sensitivity factors, these results are also represented as curves in Figures 16, 17 and 18. The common points in these figures are for our reference case which is shown in Table 34.

We can note the following from these figures.

1. It is obvious from Figure 17 that the unit O&M costs decrease when power size increases. Its decreasing rate is larger for power sizes ranging from from 100 to 200 MWe. However, for the TRENCH reactor of 300 MWe, its O&M costs are still more than 2.3 times of that of 700 MWe.

2. When the capacity factor increases, the unit O&M costs decrease with a smaller decreasing rate than that of power size.

3. We can see from Figure 16 that when power size or capacity factor increases, the total O&M costs do not increase too much. It explains why the unit O&M costs decrease so fast for increasing power size.

4. From Figure 18, the unit O&M costs decrease with a very small decreasing rate when the unit number increases from 1 to 4. This is consistent with the phenomenon that there is a nearly linear relationship between the total O&M costs and unit number.

5.2 Decommissioning Costs

Nuclear plants can not simply be abandoned at the end of their operating lives. To protect the public from the residual radioactivity, decommissioning - the process of cleaning up and burying a retired nuclear plant - is an essential step in the use of nuclear power. Although the economic competitiveness of electric-generating technologies is traditionally judged by comparing the sum of construction costs, operation costs, and fuel costs, but the cost estimates for nuclear power will be meaningful only if the decommissioning costs are incorporated into the sum.

Generally, there are three options to choose to decommission a nuclear plant.

1. Decontaminate and dismantle the plant immediately after shutdown. Tubing and structural surfaces would be mechanically and chemically cleaned. Irradiated steel and concrete would be disassembled. All radioactive debris would be shipped to a burial ground.

2. Plants would only undergo preliminary cleanup before being put into storage for several decades. During the storage period, most of the short-lived radioisotopes would have decayed, further safety treatments would be less, and the plant would then undergo dismantlement.

3. Entombment covers the reactor with reinforced concrete and erecting barriers to keep out intruders.

TABLE 32. Onsite staff requirements for the TRENCH reactor

Functions	Units per site			
	1	2	3	4
Plant manager's office				
Manager	1	1	1	1
Assistant	1	2	3	4
Quality assurance	6	6	7	8
Environmental control	1	1	1	1
Public relations	1	1	1	1
Training	12	12	12	12
Safety and fire protection	1	2	3	4
Administrative services	49	55	65	78
Health services	2	2	2	2
Security	94	94	94	94
Subtotal	168	176	189	205
Operations				
Supervision (excluding shift)	9	9	18	18
Shifts	44	88	132	176
Subtotal	53	97	150	194
Maintenance				
Supervision	12	14	26	28
Crafts	48	60	73	85
Peak maintenance annualized	55	110	165	220
Subtotal	115	184	264	333
Technical and engineering				
Reactor	5	5	7	7
Radiochemical	8	8	12	12
Engineering	16	16	16	16
Performance,reports,technicians	21	30	39	48
Subtotal	50	59	74	83
Total	386	516	677	815
Less security	292	422	583	721
Less security and peak maintenance	237	312	418	501

TABLE 33. Default values used in the LMROM code

Description	Value	Symbol
Net rating of each unit, MWe	300	M2
Total hours in a year	8766	F8
Number of units per plant	1	U
Base load capacity factor	0.7	P
Year of estimate	1986	Y
Annual net heat generation, 10^6 kWh	1840.86	A
= M2 x F8 x P x U / 1000		
Hours per year at 40 hours per week	2080	F6
Basic wage rate, $/hour	13.22	W
Operator fringe benefits	0.25	F7
as percent of basic wage rate, decimal		
Plant supervision & engineering	0.20	S1
as percent of wages & fringes, decimal		
Special penalties percent	0.10	P1
for onsite labor, decimal		
Escalation rate of wage, %/year	5	E8
Base year for cost model	1986	B2
Total staff requirements from Table 32	386	S(U)
Annual salary of staff member, $/man-year	45371	M3
= $F6xWx(1+F7)x(1+S1)x(1+P1)x(1+E8)^{Y-B2}$		
Staff requirements for maintenance	115	S3(U)
from Table 32		
Maintenance materials ratio of LMR to PWR	1.5	R1
Escalation rate of materials, %/year	5	E7
Fixed portion of maintenance material cost	0.75	F2

Table 33 (continued)

Description	Value	Symbol
Annual cost of maintenance material at reference capacity factor, $\$10^6$/year $= S3(U) \times R1 \times \frac{M3}{10^6} (\frac{1 + E7}{1 + E8})^{Y-B2}$	7.8265	B3
Variable portion of maintenance material costs	0.25	V1
Reference capacity factor in cost model	0.8	B1
Base year variable cost of supplies & expenses, mills/kWh	0.104	V5
Escalation rate of supplies & expenses	0.05	E4
Cost of supplies, radiowaste, training, lubricants, $1000/unit-year	7180	S5
Escalation rate of inspection fees	0.05	E5
Staff requirements for technical & engineering from Table 32	50	S4(U)
Salary ratio of offsite/onsite personnel	2	R2
Escalation rate of commercial liability insurance	0.05	E1
Property insurance rate, cents/$100	0.4	P5
Property insurance coverage, $1000	650,000	C3
Escalation rate of property insurance	0.05	E2
Escalation rate of replacement power insurance	0.05	E3

TABLE 34. Summary of annual O&M cost for the TRENCH reactor

NET RATING OF EACH UNIT (MWe)	300		
NUMBER OF UNITS PER PLANT	1		
BASE LOAD CAPACITY FACTOR	0.7		
GENERAL ESCALATION RATE (%/year)	5		
YEAR OF ESTIMATE	1986		
DIRECT COSTS ($\$10^6$/year)			
STAFF ONSITE (386 PERSONS AT $45371)	17.51		(X1)
MAINTENANCE MATERIAL	7.58		(X2)
FIXED		5.87	(X2F)
VARIABLE		1.71	(X2V)
SUPPLIES AND EXPENSES	7.37		(X3)
FIXED		7.18	(X3F)
VARIABLE		0.19	(X3V)
FEES, INSPECTIONS, REVIEWS	1.04		(X4)
OFFSITE SUPPORT SERVICES	4.54		(X5)
INDIRECT COSTS ($\$10^6$/year)			
ADMINISTRATIVE AND GENERAL	11.80		(AG)
COMMERCIAL LIABILITY INSURANCE		0.52	(AG1)
RETROSPECTIVE PREMIUM		0.01	(AG2)
PROPERTY INSURANCE (PRIMARY)		2.60	(AG3)
PROPERTY INSURANCE (EXCESS)		1.56	(AG4)
REPLACEMENT POWER INSURANCE		1.40	(AG5)
OTHER A&G		5.71	(AG6)
COSTS ($\$10^6$/year)			
TOTAL FIXED DIRECTS AND INDIRECTS	47.9		(TF)
TOTAL VARIABLE DIRECTS AND INDIRECTS	1.9		(TV)
TOTAL NONFUEL O&M	49.8		(T)
UNIT COSTS (mills/kWh)			
FIXED DIRECTS AND INDIRECTS	26.04		(UF)
VARIABLE DIRECTS AND INDIRECTS	1.03		(UV)
TOTAL NONFUEL O&M	27.07		(UT)

TABLE 35. Sensitivity of plant size (MWe) on O&M costs (1986 dollars)

Plant size	$ 10^6/year	mills/kWh
100	49.7	80.98
200	49.8	40.55
300	49.8	27.07
400	49.9	20.34
500	50.0	16.29
600	50.1	13.60
700	50.1	11.67

TABLE 36. Sensitivity of capacity factor on O&M costs (1986 dollars)

Capacity factor	$ 10^6/year	mills/kWh
0.6	49.5	31.39
0.65	49.7	29.07
0.7	49.8	27.07
0.75	50.0	25.35
0.8	50.2	23.84
0.85	50.3	22.51
0.9	50.5	21.32

TABLE 37. Sensitivity of unit number on O&M costs (1986 dollars)

Unit number	$ 10^6/year	mills/kWh
1	49.8	27.07
2	75.8	20.60
3	104.9	19.00
4	131.3	17.84

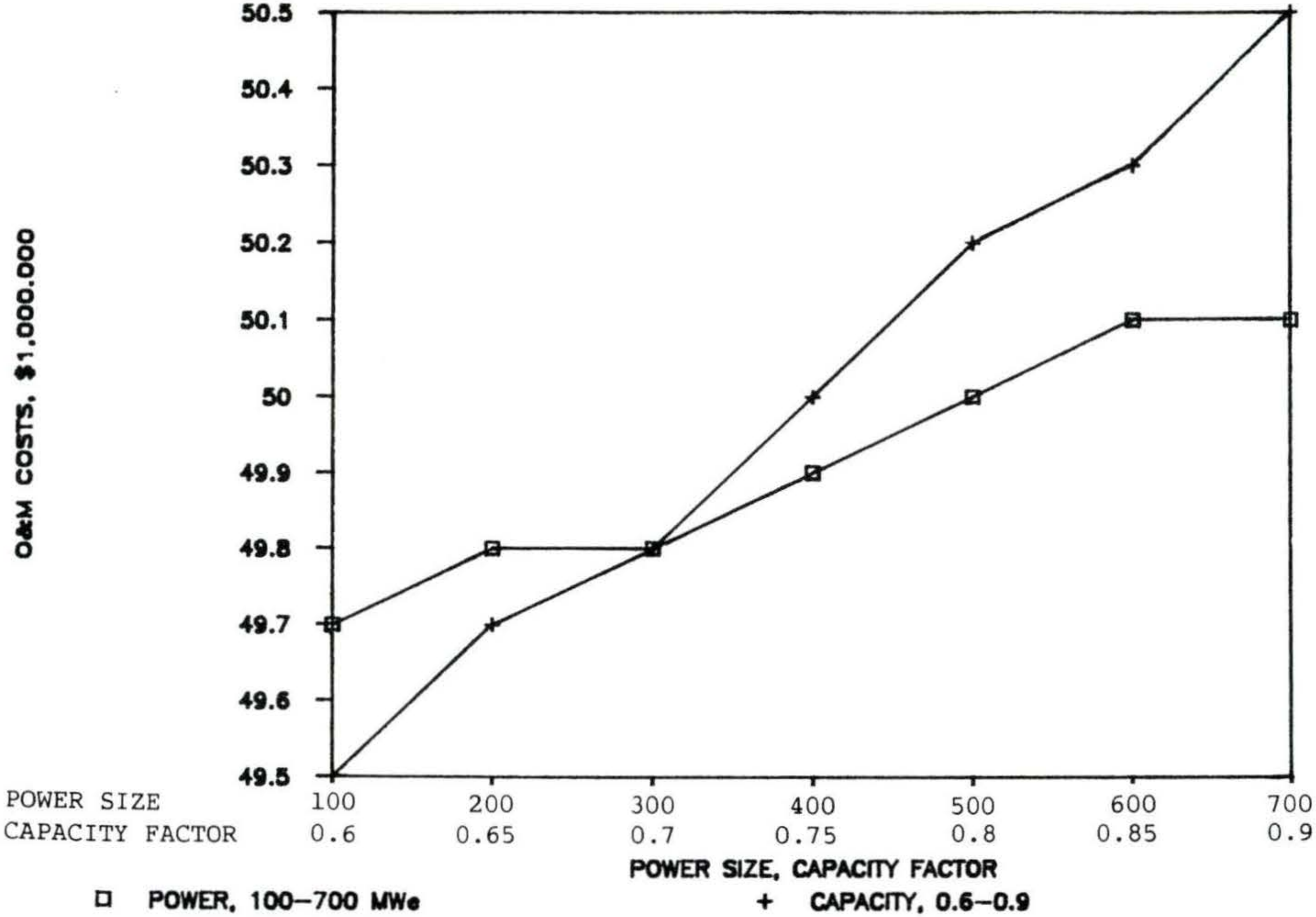


FIGURE 16. Sensitivity of plant size (MWe), and capacity factor on O&M costs ($ 10^6/year, 1986 dollars)

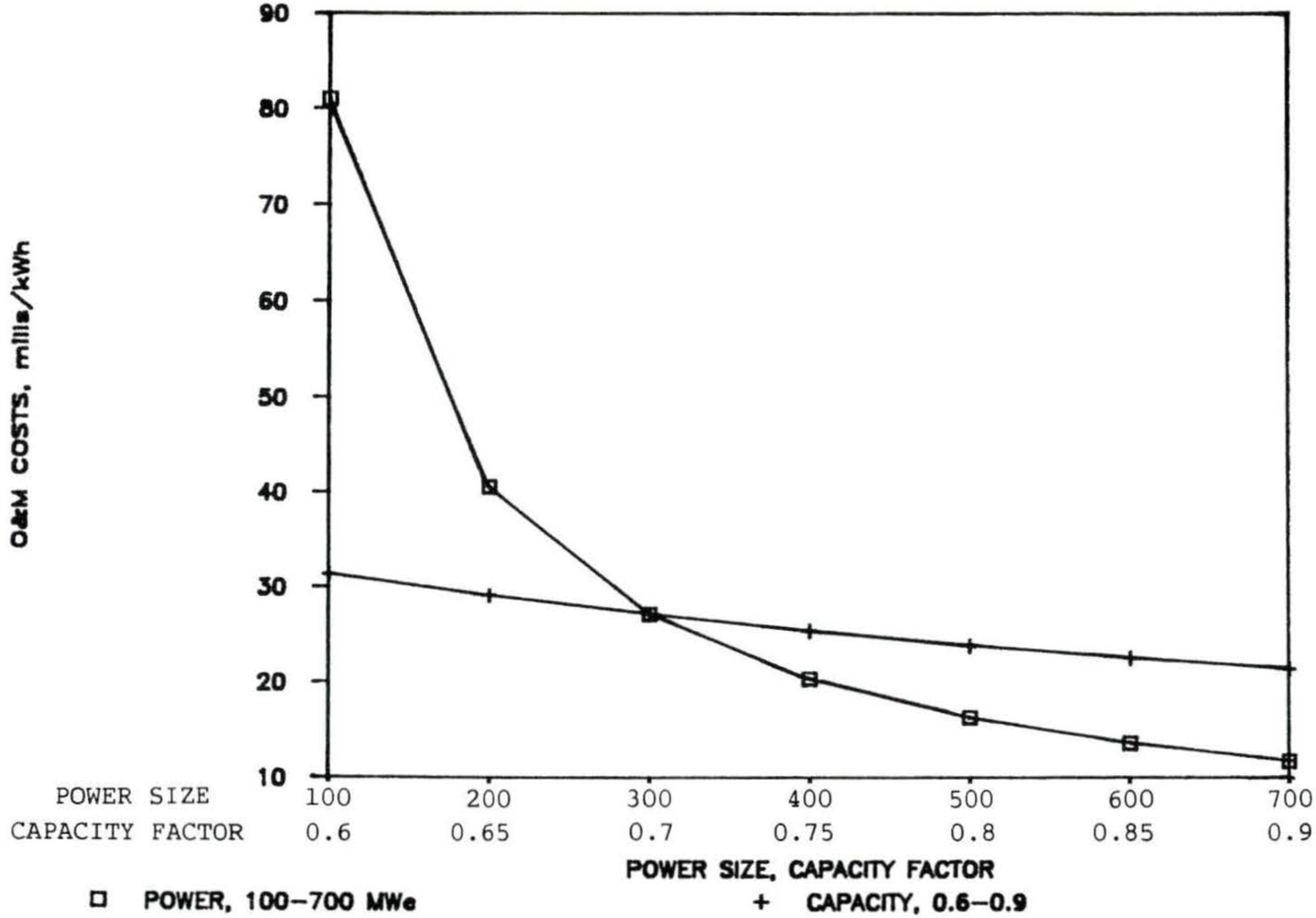


FIGURE 17. Sensitivity of plant size (MWe), and capacity factor on O&M costs (mills/kWh, 1986 dollars)

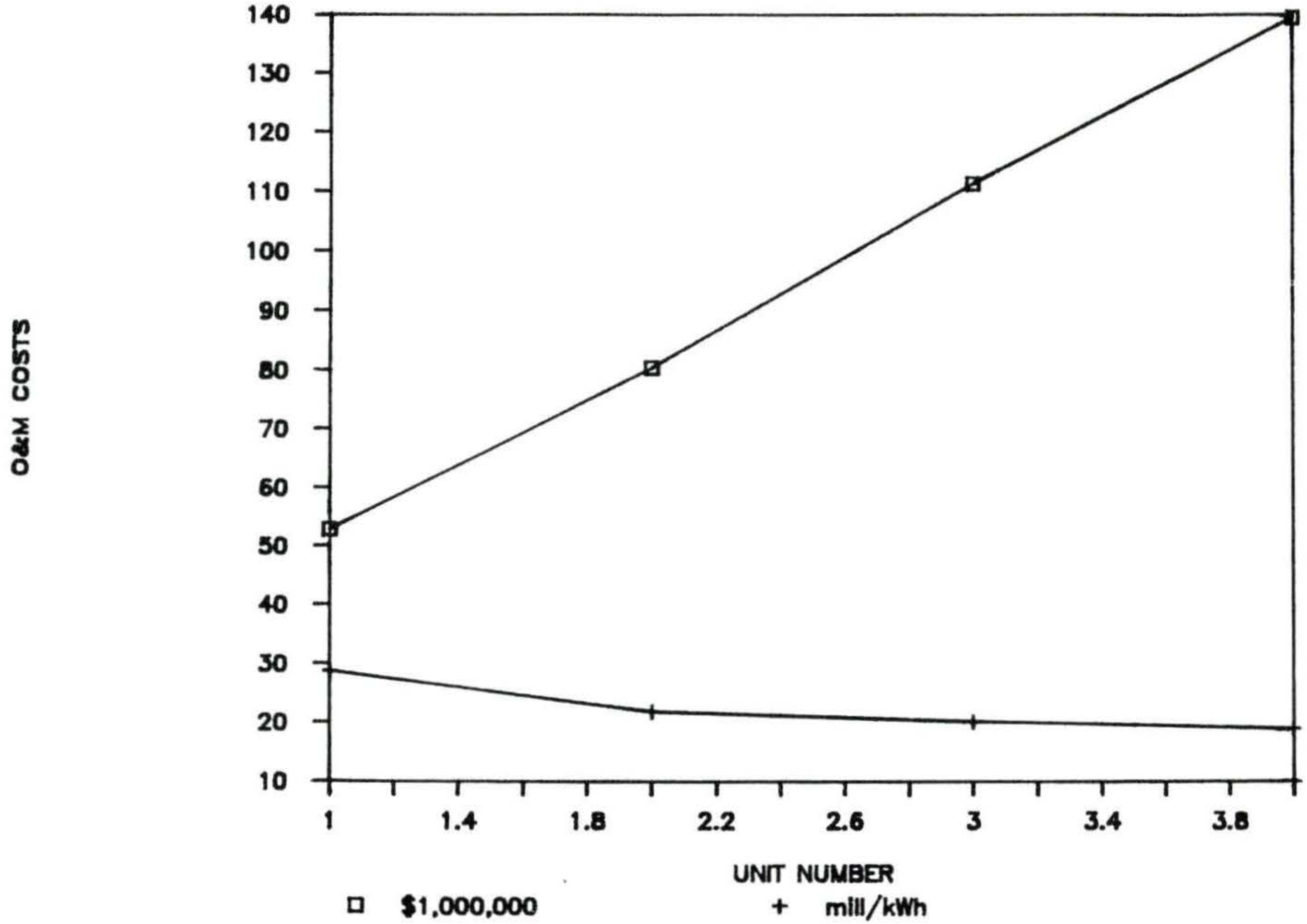


FIGURE 18. Sensitivity of unit number on O&M costs (1986 dollars)

A survey of 30 electric utilities in the United States revealed that 22 planned to choose option 1, i.e., to promptly dismantle and remove their reactors following shutdown [31].

Besides the cost and dismantlement method, the third concern about nuclear plant decommissioning is the storage of low and high level wastes. In the United States, all of the high-level spent fuel produced to date is now stored temporarily in water-filled utility holding ponds. Until 1970, the United States and many other nations discarded low-level wastes by dumping them at sea. Other disposal techniques being studied include aboveground vaults, earth-mounded concrete bunkers, and mined cavities. Because of the lack of disposal sites, it may be difficult to conduct a total discommissioning. With the concerns listed above, decommissioning would be an important problem facing the nuclear engineers in the next generation.

5.2.1 Methodology

If $(DC)_o$ is the decommissioning costs given in the reference year's dollars, the cost at the end of reactor life, L+N years, is

$$(DC)_o \ (1 + g_{DC})^{L+N}$$

The annualized cash requirement is

$$SFF(X_{SF},N) \ (DC)_o \ (1 + g_{DC})^{L+N} \tag{64}$$

where

- $SFF(X_{SF},N)$ = sinking fund factor for N years at X_{SF} after tax return [14 and 15]

$$= \frac{X_{SF}}{(1 + X_{SF})^N - 1} \quad (65)$$

Since revenues received from the rate payer must equal expenses, so in the nominal dollar case

$$\overline{P}_{DC}S_A = SFF(X_{SF},N)(DC)_o(1 + g_{DC})^{L+N}$$

Therefore, the equal annual payment per kWh in nominal dollars into the sinking fund which accumulates the decommissioning costs is

$$\overline{P}_{DC} = \frac{SFF(X_{SF},N)(DC)_o(1 + g_{DC})^{L+N}}{(\text{electric energy produced per year})} \quad (66)$$

The constant dollar decommissioning costs become

$$\overline{P}_{oDC} = \frac{SFF(X_{oSF},N)(DC)_o(1 + r_{DC})^{L+N}}{(\text{annual energy production})} \quad (67)$$

Generally speaking, in the reference case the escalation rate for decommissioning costs was assumed to be the general inflation rate, i.e., $g_{DC} = i$, so that $r_{DC} = 0$. Another method to get $\overline{P}_{oDC}$ is from eq. (29).

5.2.2 Estimated costs

The cost of decommissioning nuclear power plants is highly speculative. Cost estimates have been derived from generic studies, from scaling up of the decommissioning costs of smaller research facilities, from calculations based on a fixed percentage of construction costs, and more recently from site-specific engineering studies. Because of the limited decommissioning experience, none with large commercial reactors, it becomes difficult to know if the estimates are on target.

A study conducted by the Battelle Pacific Northwest Laboratory in 1978 concluded that the decommissioning costs depend primarily on the reactor design and the number of years after shutdown that dismantlement would be deferred. The major expenses associated with decommissioning are the packaging, transportation, and burial of wastes; labor; energy; demolition; and equipment.

A recent site-specific, rather than generic, decommissioning cost estimates for two 1,100 MWe LWR are $140 million for a PWR and $134 million for a BWR [13 and 31], excluding the costs of removing nonradioactive structures. Estimates derived from scaling up costs of smaller facilities, and from assuming a fixed percentage of construction expenditures are even higher. In Japan, a study concluded that dismantling a 1,100 MWe plant after five years of storage will cost 160 million. Some estimated decommissioning costs are summarized in Table 38 [31].

As experience is gained in decontamination, dismantlement, waste handling, and disposal, inadequacies in existing regulations will emerge. The biggest regulatory gaps at present are the lack of criteria for classifying wastes as either radioactive or

TABLE 38. Estimated decommissioning costs for nuclear power plants no longer in operation, in $\$10^6$ of 1985 dollars

Owner/Site	Capacity MWe	Cost $\$10^6$	Cost/MWe $\$10^6$/MWe	Operating Period
U.S. Elk River	22	14	0.58	1964-68
U.K. Windscale	33	64	1.94	1962-81
Pacific Gas & Electric Humboldt Bay-Unit 3	65	55	0.85	1963-76
U.S. Shippingport	72	98	1.36	1957-82
Commonwealth Edison Co., Dresden-1	210	95	0.45	1960-78

nonradioactive, and the uncertainties regarding the method of transuranic waste disposal, and the absence of "residual radioactivity" standards. If the final rules are stricter, costs would rise substantially.

In the absence of a specific decommissioning estimates, we will use the default value [13], \$140 million (1986 dollars) for an 1100 MWe unit. It can be linearly scaled, i.e., using \$127.27/kWe for the TRENCH reactor. Therefore, the total decommissioning costs for the TRENCH reactor are estimated to be \$38.18 million (1986 dollars). Assuming the decommissioning costs escalate at the general inflation rate, 5%, and that decommissioning funds are to be accumulated in 30 years, the net decommissioning costs for the TRENCH reactor at the end of 30 years of operation in the year 2030 are \$326.7 million. This amount is accumulated in a sink fund at the tax-free state government debt rate of 6.5%/year nominal or 1.4%/year real.

5.2.3 Method of financing

The method of financing the decommissioning fund is still under discussion. One method, which has been adopted by some public utility commissions, is to set up an external sinking fund to accumulate the necessary decommissioning funds. Other possible funding methods include prepayment, internal reserve, and insurance. The taxation policy can have a significant effect on the cost of funding. A recent Internal Revenue Service rule [32] allows for the tax deduction of payments into an external decommissioning sinking fund. However, the interest on the sinking fund balance is subject to federal income taxes.

6. DISCUSSION AND CONCLUSION

6.1 Total Levelized Power Generation Costs

The methodologies and results obtained in the preceding Chapters are summarized to get the levelized power generation costs. The PC program LEVEL is used to get the results which are shown in Table 39.

TABLE 39. Levelized power generation costs (mills/kWh) for the TRENCH reactor

Component	Constant		Nominal
Capital	82.97	(71.27%)	278.5
O&M	27.07	(23.25%)	90.9
Fuel	5.76	(4.95%)	19.3
Decommission	0.61	(0.52%)	2.1
Total	116.41		390.8

By examining the results above, we can note that the O&M costs is the second largest part and much larger than the fuel costs. It makes up 23% of the total levelized costs.

A survey of selected O&M cost data [33] shows a minimum value of 5.1 mills/kWh for a 1786 MWe unit and a maximum value of 15.0 mills/kWh for a 668 MWe unit. The predictions from Table 35 show a 13.6 mills/kWh for a unit of 600 MWe and 11.67 mills/kWh for a unit of 700 MWe, respectively. The value of 15.0 is a little higher than our predictions. However, there are two units of 484 MWe and 470 MWe to report the O&M costs of 10.3 mills/kWh and 11.0 mills/kWh, respectively. Our prediction for a 500 MWe unit from Table 35 is 16.29 mills/kWh, which is larger than the reported data. The gap is due to the fact that the uncertainty of prediction becomes larger when power size decreases.

From the comparisons above, the consistency of the prediction with the reported data seems acceptable. Since there is no reported O&M costs for a plant of 300 MWe, we can not compare and verify the O&M costs for the TRENCH reactor. However, we can reduce the O&M costs for a small power plant in two directions.

1. Since the staff costs make up 35% of the O&M costs and is larger than other cost components, we can make a thorough inspection of the staff requirements to decrease the unnecessary staff members and make smaller staff costs.

2. We can estimate the maintenance materials and supplies for a small plant. The sum of these two costs make 30% of the O&M costs.

An examination of the data reported by the utilities on Form 1 to the federal government shows a wide variation in onsite staffing requirements and consequently the total O&M costs.

The fluctuations of the O&M costs come from three factors.

1. There is no standardized approach to estimate the O&M costs.

2. Many utilities contract activities such as security, peak maintenance, health physics and quality control.

3. The management philosophy affects the distribution of onsite and offsite staff requirements.

Our estimate of the decommissioning costs, \$127.27/kWe, is much smaller than the estimate from Table 38, which is at least \$450/kWe. Besides, the stricter regulations for the decommissioning would make the actual expenditures larger than our present estimate.

To show the effects of inflation rate and lead time on the total levelized costs, the results obtained in the preceding Chapters are summarized in Tables 40 and 41. When the lead time increases from 8 to 12 years, the total levelized costs in constant dollars increase by 13%.

TABLE 40. Sensitivity of total levelized costs (in mills/kWh of 1986 year dollars) on inflation rate

	Inflation rate, %/year					
Component	3	4	5	6	7	8
Capital	136.12	106.48	82.97	64.41	49.80	38.35
O&M	27.07	27.07	27.07	27.07	27.07	27.07
Fuel	9.45	7.39	5.76	4.47	3.46	2.66
Decom.	0.43	0.52	0.61	0.72	0.84	0.98
TOTAL	173.07	141.46	116.41	96.67	81.17	69.06

6.2 Future Developments of LMFBR

In the development of the next generation of advanced reactors, it becomes clear to concentrate on four major goals [34]. A brief discussion follows.

TABLE 41. Sensitivity of total levelized costs (in mills/kWh of 1986 year dollars) on lead time

	Lead time, year				
Component	8	9	10	11	12
Capital	82.97	86.72	90.22	94.12	98.18
O&M	27.07	27.07	27.07	27.07	27.07
Fuel	5.76	5.76	5.76	5.76	5.76
Decom.	0.61	0.61	0.61	0.61	0.61
TOTAL	116.41	120.16	123.66	127.56	131.63

6.2.1 Passive or inherent safety

The TMI-2 accident gave impetus to thought about the desirability of reactors that could make reactors more invulnerable to events which would normally initiate serious accidents. Metallic fuel used in the TRENCH reactor has a higher degree of inherent safety than the conventional oxide fuel. The TREAT experiments performed to date indicate that the margin to fuel pin failure during transient overpower conditions is greater for metal than oxide fuel. However, the metallic fuel shows its greatest advantages over the oxide fuel under the generic anticipated-transient-without-scram (ATWS) events, such as loss-of-flow-without-scram (LOFWS), loss-of-heat-sink-without-scram (LOHSWS), and transient-overpower-without-scram (TOPWS). It is worth stressing that the improved performance characteristics of the metallic core are directly traceable to the basic properties of the fuel, and not to the engineered features of any kind.

6.2.2 Fuel cycle closure including waste treatment

The LMR has potential for extending the uranium source by a factor of 50-100 compared to the the present-day commercial light water reactors. LMR spent fuel contains fissile value similar to fresh fuel, in contrast to the LWR where the fissile worth of spent fuel is less than 20% of the fresh fuel. In addition, the long fuel residence characteristics of the TRENCH reactor makes the volume of radioactive waste less.

6.2.3 Plant capital costs

To reduce the capital investment costs, the plant design should evolve with simplicity as a primary guiding principle. Most of the capital costs of LWR are associated with the balance-of-plant (BOP) and indirect costs. We can see from Figure 13 that the indirect costs of PWRM is larger than the direct costs. The nuclear reactor itself constitutes only a small fraction of the capital costs. For the TRENCH reactor, the direct costs are only 28.9 % of the total capital costs. The indirect costs contribute 24.6 %, and other 46.1 % are from contingency and interest. In particularly, the interest is almost 35.5 % of the total capital costs. To decrease the lead time to make the interests small would be an essential step to make the LMR competitive with the coal plant.

The LMR do as well or better in the BOP and indirect costs. Because of the higher thermal efficiency of sodium, the heat rejection system of the TRENCH reactor is smaller than the PWRB and the turbine plant can be better optimized. Electrical systems should be about the same. Structures and buildings should be less because high pressure capability may not be necessary for containment.

A large thermal inertia associated with the sodium pool combined with favorable reactivity feedback characteristics of the metallic fuel makes the reactor system immune to various transients originating from the BOP. We can see from Figure 13 that the only area that the LMR is more costly than the LWR is the reactor plant itself.

A crude but representative indicator for the reactor plant cost is the masses of the reactor system components. Therefore, we can estimate the cost of a component by assuming that the cost is proportional to the weight. To reduce the total masses, the recent LMR conceptual design efforts, such as the PRISM and SAFR projects, simplify the reactor vessel enclosure and internal structures. To further reduce the total masses, they use seismic isolation system which is also used in the TRENCH reactor. If both horizontal and vertical isolations can be achieved, major reductions are possible in the weights of reactor enclosure system structures, as well as pumps, intermediate heat exchangers, and steam generators. In addition, the reactor system unit mass is a strong function of the reactor size. Therefore, we can take advantage of reducing the number of steam generators, pumps and IHX to reduce the reactor size and consequently the cost.

6.2.4 Operability and reliability

Sodium is noncorrosive to the metals used in the LMR reactor structures and components. Radioactive corrosion products are not formed in any significant amounts. It makes access for maintenance easy and radiation exposures to plant personnel low compared to LWR. A noncorrosive coolant also implies reliable sodium components performance and improved plant availability.

As for the results obtained and the deficiencies confronted so far, our future work could be in the following directions.

1. A more complete design of the SAFEGUARD SYSTEM to provide the decay heat removal.
2. A thorough inspection of the satff requirements to reduce the O&M costs and make it more economic to operate a small plant.
3. A specific estimate of the decommissioning costs.
4. The creep of cables would become important when the temperature increases. The material properties of the cable system need to be examined.

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8. ACKNOWLEDGEMENTS

The author expresses a great deal of thanks to his major professor, Dr. A. F. Rohach. Without his knowledge of the subject and insight into the problem, this study would not have come into being. Dr. B. I. Spinrad also has my deepest appreciation for many helpful discussions and suggestions throughout the course of the research. In addition, the author would like to thank Dr. John Sankoorikal for many helps throughout the two years.

The financial support supplied by the Department of Energy and the technical services supplied by Oak Ridge National Laboratory were instrumental in the progress of this study. Finally, the author is deeply grateful to his families for their understanding and encouragement and dedicates this report to his mother.

9. APPENDIX: NSSS COST BREAKDOWNS

TABLE 42. Equipment list and cost estimate for the NSSS of the TRENCH reactor [20 and 35]

Account description	Value
220A.21 REACTOR EQUIPMENT	
220A.211 REACTOR VESSEL	
220A.2111 REACTOR VESSEL SHELL	
Number of components	1
Heat load	800 MWt
Safety class	Section III Class I
Material	304 S.S.
Vessel	
Length	22 m
Width	4 m
Height	17 m
Thickness	1 cm
Weight	165,634 lbs
Nozzles	
Inlet-Quantity/I.D.	2/35"
Outlet-Quantity/I.D.	2/43"
Other-Quantity	8
Weight	8600 lbs
Weld metal	
Length	344 m
Weight	26,629 lbs
Support system	
Material	Carbon steel
Dimension	See Figure 6
Weight	6550 lbs.
Miscellaneous items weight	5766 lbs
Total weight	213,179 lbs
Total cost	$5,710,468

TABLE 42 (continued)

Account description	Value
220A.2112 CLOSURE HEAD	
Material	S.S.
Safety class	Section III Class I
Closure head	
Quantity	5
Component type	Plate attached
Length	4.5 m
Width	4 m
Thickness	2.5 cm
Weight	38,485 lbs.
Cost	$532,024
Seals	
Quantity	5
Material	Silicon rubber and liquid metal
Cost	$82,840
No. of control rod penetrations	14
Total cost	$614,864
220A.2113 GUARD VESSEL	
Material	Carbon steel
Number of components	1
Safety class	Section III Class III
Height	18.5 m
Thickness	1 cm
Width & Length	See Figure 8
Weight	287,986 lb.
Cost	$7,929,157
220A.211 TOTAL WEIGHT	539,650 lbs
TOTAL COST	$14,254,489

TABLE 42 (continued)

Account description	Value
220A.212 REACTOR VESSEL INTERNALS	
Number of components	1
Material	304 S.S.
Lower internals	
Core support structure (table)	
Length	7.5 m
Width	1 m
Thickness	1 cm
Columns	
Quantity	10
Diameter	5 cm
Height	1 m
Weight	1611 lbs
Cost	$63,143
Upper internals	
Instrument tree assembly	
Quantity	1
Weight	160,000 lbs
Cost	$5,470,264
Inlet piping (In-vessel)	
Quantity	2
Length/I.D./thickness	12m/1m/1cm
Weight	12,961 lbs
Cost	$411,190
Check valve	
Quantity/size	2/36"
Weight	12,000 lb.
Cost	$421,063
Instrumentation assemblies	
Quantity	20
Cost	$915,389
Total weight	186,572 lbs
Total cost	$7,281,049

TABLE 42 (continued)

Account description	Value
220A.213 CONTROL ROD SYSTEM	
Material	304 S.S.
Control rod drives	
Quantity	14
Cost	$2,153,171
Control rods	
Quantity	14
Weight	22,568 lbs
Cost	$604,530
Total cost	$2,757,701
220A.214 CABLE	
Material	Carbon steel
Number of pairs	50
Spacing between pairs	0.5 m
Diameter	1.125"
Weight	17,866 lbs
Cost	$18,759

TABLE 42 (continued)

Account description	Value
220A.221 PRIMARY HEAT TRANSPORT SYSTEM	
220A.2211 PRIMARY PUMP, MOTOR & CONTROL	
Safety class	I
Material	S.S.
Pump	
Quantity	2
Type	Centrifugal/Single Stage
Orientation	Vertical
Flow rate/per pump (10^6 lb./hr.)	17.46
Scaling factor	0.7 (by flow rate)
Weight	365,384 lbs.
Cost	$6,828,846
Motor	
Quantity	2
Type	Induction AC
Weight	12,000 lbs
Scaling factor	0.8 (by flow rate)
Cost	$998,650
Speed control	
Quantity	2
Type	Motor/Generator
Weight	12,000 lbs
Scaling factor	0.8 (by flow rate)
Cost	$1,398,030
Pony motor	
Quantity	2
Scaling factor	0.8 (by flow rate)
Cost	$99,945
Total weight	389,384 lbs
Total cost	$9,325,471
220A.22121 PRIMARY PIPING	None
220A.22122 PRIMARY VALVES	None

TABLE 42 (continued)

Account description	Value
220A.2213 INTERMEDIATE HEAT EXCHANGER	
Scaling factor	0.85 (by flow rate)
Number of components	2
Component type	St. tube/St. shell
Flow characteristics	Counterflow
Orientation	Vertical
Net load per component	400 MWt
Safety class	Section III Class I
Shell side conditions	
Fluid	Na
Flow rate/per IHX (10^6 lbs/hr.)	17.46
Inlet/outlet temperature	482/343° C
Tube side conditions	
Fluid	Na
Flow rate/per IHX (10^6 lbs/hr.)	14.127
Inlet/outlet temperature	294/460° C
Nozzles	
Shell side inlet-Quantity/I.D.	1/35"
Shell side outlet	1/35"
Tube side inlet	1/35"
Tube side outlet	1/35"
Material	304 S.S.
Total weight	656,590 lbs
Total cost	$9,462,480
220A.221 TOTAL WEIGHT	1,045,974 lbs.
TOTAL COST	$18,787,951

TABLE 42 (continued)

Account description	Value
220A.222 INTERMEDIATE HEAT TRANSPORT SYSTEM	
220A.2221 SECONDARY PUMP, MOTOR & CONTROL	
Pump	
Material	304 S.S.
Quantity	2
Type	Centrifugal
Orientation	Vertical
Flow rate/per pump (10^6 lb./hr.)	14.127
Safety class	NNS
Scaling factor	0.7 (by flow rate)
Cost	$4,719,017
Motor	
Quantity	2
Type	AC Induction
Scaling factor	0.8 (by flow rate)
Cost	$801,920
Speed Control	
Quantity	2
Type	Motor/Generator
Scaling factor	0.8 (by flow rate)
Cost	$1,247,471
Pony motor	
Quantity	2
Scaling factor	0.8 (by flow rate)
Cost	$89,182
Total cost	$6,857,590
220A.22221 SECONDARY PIPING	
Safety class	NNS
Material	304 S.S.
Large piping	
Thickness	0.5"
Length/Diameter	200'/36" OD 200'/26' OD
Cost	$603,561
Small piping	
Length/Diameter	348'/6"
Cost	$25,089
Supports materials	
Cost	$443,784
Total cost	$1,072,434

TABLE 42 (continued)

Account description	Value
220A.22222 SECONDARY VALVES	
Safety class	NNS
Material	304 S.S.
Large valves	
Quantity/Size	2/36"
Type	Isolation
Cost	$631,239
Small valves	
Quantity/Size	10/6"
Type	Isolation
Cost	$518,087
Total cost	$1,149,326
220A.2224 SECONDARY EXPANSION TANK	
Scaling factor	0.85 (by flow rata)
Number of components	2
Safety class	NNS
Material	304 S.S.
Total cost	$314,368
220A.222 TOTAL COST	$9,393,718

TABLE 42 (continued)

Account description	Value
220A.223 STEAM GENERATION SYSTEM	
220A.2232 STEAM GENERATOR	
Scaling factor	0.7 (by flow rate)
Number of components	2
Heat load per component	400 MWt
Component type	Hockey-Stick
Flow characteristics	Counterflow
Shell side conditions	
Flow rate/per S.G. (10^6 lb./hr.)	14.127
Fluid	Na
Inlet/Outlet temperature	460/294° C
Tube side conditions	
Flow rate/per S.G. (10^6 lb./hr.)	1.373
Fluid	H_2O
Inlet/outlet temperature	237/425° C
Safety class	NNS-ASME Section VIII
Total cost	$15,949,053
220A.2233 Na/H_2O REACTION PROTECTION SYSTEM	
Scaling factor	0.8 (by quantity)
Material	304 S.S.
Rupture disks	
Quantity	8
Reaction products separation tanks	
Quantity	2
Steam water dump tanks	
Quantity	2
Sodium dump tanks	
Quantity	2
Tank cost	$5,335,910
Piping	
Length/Diameter	439'/26" 742'/6"
Material	Carbon steel
Cost	$347,462
Valves	
Quantity	21
Type	Gate
Cost	$581,551
Total cost	$6,264,923

TABLE 42 (continued)

Account description	Value
220A.223 TOTAL COST	$22,213,976
220A.23 SAFEGUARDS SYSTEM	
220A.231 BACKUP HEAT REMOVAL SYSTEM	
Scaling factor	0.7 (by power size)
Material	304 S.S.
Decay heat removal pumps	
Safety class	2
Type	EM
Quantity/Fluid	2/Na 2/NaK
AHTS fans	
Quantity	4
Type	Centrifugal
Cost (Pumps & fans)	$1,184,640
AHTS heat exchangers	
Quantity	2
Type	Shell/Tube
Fluid	Na/NaK
Safety class	1
AHTS ABHX	
Quantity	4
Type	Forced convection
Fluid	NaK/Air
Safety class	2
Cost (Heat exchangers & ABHX)	$2,383,359
Piping	
Quantity	347'
Cost	$564,702
Valves	
Type	Isolation
Quantity	18
Cost	$1,274,944
Tanks	
Quantity	2
Type	NaK expansion
Cost	$90,305
Total cost	$5,497,950

TABLE 42 (continued)

Account description	Value
220A.25 FUEL HANDLING AND STORAGE	
220A.251 RECEIVING, STORAGE & SHIPPING	
New fuel handling crane	
New fuel storage racks	
Total cost	\$2,000,000
220A.252 EX-VESSEL STORAGE TANK & GUARD VESSEL	
Fluid	Na
Safety class	2
Tank	
Quantity	1
Material	304 S.S.
Width	2 m
Length	10 m
Height	5 m
Thickness	1 cm
Weight	27,347 lbs
Cost	\$677,357
Guard vessel	
Quantity	1
Material	Carbon steel
Width	2.6 m
Length	10.6 m
Height	6 m
Thickness	1 cm
Weight	37,132 lb.
Cost	\$919,750
Total cost	\$1,597,107
220A.253 EX-VESSEL HANDLING MECHANISMS	
No scaling (same cost as Target reactor)	
EVHM trolley line	
Number of runs	2
Track length	89'
Load on rails (tons)	16
Weight	4000 lbs
Spent fuel rails	
Track length	50'

TABLE 42 (continued)

Account description	Value
Load on rails (tons)	37
Weight	2500 lbs
Cost (Trolley + rail line)	$42,603
EVHM	
Numbers	2
Dimension	2'x8'x5'
Motor (number)	4
Drive (number)	6
Weight	16 tons
Cost	$4,552,873
Spent fuel cask cart	
Dimension	12'x12'x22'high
Motor (number)	4
Drive (number)	3
Weight	24,000 lbs
Cost	$301,063
Total cost	$4,896,539
220A.254 TRANSFER MECHANISMS	
No scaling (same cost as TARGET reactor)	
Fuel transfer tracks (reactor vessel - EVST)	
Number of runs	2
Track length	168'
Weight	8000 lbs
Cost	$63,905
Fuel transfer buckets	
Numbers	2
Dimension	15'x10"x20"x0.25"thick
Weight	2,000 lb.
Cost	$31,242
Handling machine	
Dimension	5'x8'x5'high
Motor	2
Drive	3
Weight	16 tons
Total cost	$95,147
220A.255 IN-VESSEL HANDLING MECHANISMS	None
220A.256 FUEL HANDLING CELLS	None

TABLE 42 (continued)

Account description	Value
220A.257 PIPING & VALVES	None
220A.258 MISCELLANEOUS EQUIPMENT	
Scaling factor	0.5 (by power size)
EVST NaK expansion tanks	
Quantity	2
Material	Carbon steel
Height/Diameter	2.5'/2.4'
Volume	70 gallons
Cost	$8577
Pumps	None
Heat exchangers	
Material	304 S.S.
Quantity	2
Type	EVST heat exchanger Shell/Tube
Fluid	NaK/Na
Flow	530/326 GPM
Quantity	2
Type	EVST ABHX, Shell/Tube
Fluid	Air/NaK
Flow	19140 CFM/456 GPM
Quantity	2
Type	EVST cold trap, regenerative, Shell/Tube
Fluid	Radioactive Na
Flow	46.5/46.5 GPM
Cost	$411,020
Purification	
Quantity	2
Type	EVST cold traps
Fluid	Radioactive coolant
Flow	46.5 GPM
Material	304 S.S.
Quantity	2
Type	NaK diffusion traps
Material	Carbon steel
Cost	$597,728
Total cost	$1,017,325
220A.25 TOTAL COST	$9,606,118

TABLE 42 (continued)

Account description	Value	
220A.26 OTHER EQUIPMENT		
220A.261 INERT GAS RECEIVING & PROCESSING		
220A.2611 PUMPS, COMPRESSORS & DRIVES		
No scaling (same cost as TARGET reactor)		
Compressors		
Material	304 S.S.	
Quantity	3	
Type	RAPS compressors	
Flow	25 CFM	
Quantity	2	
Type	CAPS compressors	
Flow	50 CFM	
Total cost	$715,735	
220A.2612 GAS SUPPLY/STORAGE TANKS		
No scaling (same cost as TARGET reactor)		
Material	304 S.S.	
Nitrogen storage tanks	Liquid	Gaseous
Quantity	3	3
Height/Diameter	20'/7'	15'/10'
Volume (gallons)	6000	6000
Argon storage tanks		
Quantity	9	
Height/Diameter	7'/6'	
Volume	1,500 gallons	
Inert gas vacuum tank		
Quantity	2	
Height/Diameter	14'/7'	
Volume	538 $ft.^3$	
Inert gas delay tank		
Quantity	2	
Height/Diameter	25'/7'	
Volume	960 $ft.^3$	
Noble gas storage tank		
Quantity	1	
Height/Diameter	15'/5'	
Volume	300 $ft.^3$	

TABLE 42 (continued)

Account description	Value
Recycle argon tank	
Quantity	1
Height/Diameter	10'/10'
Volume	750 $ft.^3$
Total cost	$3,490,630
220A.2613 INERT GAS PURIFICATION SYSTEM	
Scaling factor	0.5 (by power size)
Material	304 S.S.
Nitrogen vaporizer	
Quantity	10
Flow	2323 SCFM
Argon vaporizer	
Quantity	9
Flow	2323 SCFM
Nitrogen filter	
Quantity	2
Flow	232 SCFM
Argon filter	
Quantity	2
Flow	116 SCFM
Vapor traps	
Quantity	25
Capacity	2.3 SCFM
Purification unit	
Quantity	1
Nitrogen/Argon charcoal beds	
Quantity	5
Height/Diameter	14'/13.5'
Volume	236 $ft.^3$
Material	PCB charcoal
Distillation unit	
Quantity	1
Flow	11.6 SCFM
RAPS regenerative heat exchanger	
Quantity	2
Type	Tube/Shell
Flow	11.6 SCFM
RAPS argon coolers	
Quantity	2
Flow	11.6 SCFM

TABLE 42 (continued)

Account description	Value
CAPS nitrogen coolers	
Quantity	8
Flow	70 SCFM
Total cost	$1,784,607
220A.2615 PIPING, VALVES & FITTINGS	
No scaling (same cost as TARGET reactor)	
Valves	
Quantity	146
Type/Size	Plug/2"
Material	304 S.S.
Piping	
Diameter	2"
Length/Material CAPS -------	1700'/Carbon steel
PHTS argon -	2100'/304 S.S.
IHTS argon -	1500'/Carbon steel
Freeze vent	
Material	304 S.S.
Quantity/Size	37/3"x30" 8/27 ft.^{3}
Total cost	$5,930,379
220A.262 SPECIAL HEATING SYSTEMS	
Scaling factor	0.7 (by power size)
220A.2215 Primary heat transport system - heating system	
220A.2225 Intermediate heat transport system - heating system	
Total cost	$3,663,644
220A.264 Na RECEIVING, STORAGE & MAKEUP	
Material	304 S.S.
Primary Na storage tanks	
Quantity	8
Size	25'x20'x3/4"
Volume	58,752 gallons
Intermediate Na storage tanks	
Quantity	2
Size	25'x20'x3/4"
Volume	58,752 gallons

TABLE 42 (continued)

Account description	Value
NaK storage tanks	
Quantity	3
Height/Diameter	7'/4.9'
Volume	900 gallons
Filters	
Quantity	2
Type	Na particulate
Flow	180 GPM
Quantity	1
Type	NaK particulate
Flow	45 GPM
Valves	
Type	Plug
Quantity/Size	9/2" 48/2" 16/3"
Tanks (Oil bubblier)	
Quantity/Size	6/(3'x3')
Volume	202 gallons
Material	Carbon steel
Piping	
Length/Diameter	1400'/3" 1700'/3" 150'/3"
Scaling factor	0.7 (by power size)
Total cost	$5,964,953
220A.265 Na PURIFICATION SYSTEM	
Scaling factor	0.7 (by power size)
Material	304 S.S.
Overflow pumps	
Quantity/Type	2/EM
Fluid	Primary Na
Flow	120 GPM
Primary cold trap cooling pumps	
Quantity/Fluid	2/NaK
Flow	54.7 GPM
IHTS cold trap pump	
Quantity/Fluid	4/Na
Flow	24 GPM

TABLE 42 (continued)

Account description	Value
IHTS cold trap cooling pumps	
Quantity	2
Fluid	NaK
Flow	34 GPM
Heat exchangers	
Primary cold trap regenerative	
Quantity	2
Type	Shell/Tube
Fluid	Primary Na/Primary Na
Flow	34/34 GPM
Intermediate Na regenerative	
Quantity	4
Type	Shell/Tube
Fluid	Inter. Na/Inter. Na
Flow	34/34 GPM
Primary overflow tank	
Quantity	1
Height/Diameter	12.5'/16.5'
Volume	20,086 gallons
HTS NaK expansion tank	
Quantity	4
Height/Diameter	1.5'/1.65'
Volume	24 gallons
Filters	
Primary cold trap	3
Intermediate Na cold trap	4
NaK diffusion cold trap	5/Carbon steel
Valves	
Quantity/Size	6/2" 8/3"
Piping	
Length/Diameter	68'/3" 136.7'/2"
Scaling factor	0.7 (by power size)
Total cost	$2,463,954
220A.26 TOTAL COST	$24,013,902

TABLE 42 (continued)

Account description	Value
220A.27 INSTRUMENTATION & CONTROL SYSTEM EQUIPMENT	
Data processing system	
Plant protection system	
Supplementary reactor protection system	
Containment isolation system	
In-vessel flux monitoring system	
Ex-vessel flux monitoring system	
Vessel & internals monitoring system	
Equipment operating surveillance	
Radiation monitoring equipment	
Control systems	
Process instrumentation	
PHTS & IHTS	
S.G. system	
Intermediate Na purification system	
Primary Na purification system	
Na & NaK receiving system	
Primary Na storage & processing	
Ex-vessel storage	
Primary Na cold trap	
Intermediate Na processing system	
Component control system	
Control element drive mechanism control system	
Piping & equipment electrical heating system	
Remote shutdown system	
Control panels	
No scaling (same cost as TARGET reactor)	
Total cost	$32,456,614