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ECONOMIC HANDBOOK

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INTRODUCTION

One method of assessing the merits of a nuclear power plant of a particular type as compared with others, or with a plant burning conventional fossil fuels, is to use the total power-generating cost as a criterion. It is not intended in this introduction to discuss whether the power-generating cost may be considered as a valid criterion to determine the relative merit; it is certainly not the only one.

The present handbook is concerned with the power-generating cost as such. Enquirers are still confronted with a multitude of cost price estimates from a wide variety of sources, so that it is very difficult to decide on the exact relative meaning of the various figures.

The Euratom Commission has been keenly aware of this fact. The need to devise a uniform method for calculating nuclear electricity production costs has been apparent almost since the very beginning of nuclear power-generating history and is still very real. The first effort in this direction goes back to the first Venice Symposium of October 1963, where for the first time in the Community a basic scheme was discussed with representatives of all interested parties, i.e. the Commission itself, government organizations, nuclear equipment industries and the power utilities.

At the end of 1963, the Commission signed a contract with a representative group of the Community called "Groupement for the Euratom Economic Handbook" composed of the

— Commissariat à l'Énergie Atomique	— France
— Société Indatom	— France
— Siemens-Schuckert Werke AG	— W. Germany
— Società Ricerche Impianti Nucleari (SORIN)	— Italy

The following organizations or firms acted as consultants to these contractors:

— Électricité de France	— France
— Rheinisch-Westfälisches Elektrizitätswerk AG	— W. Germany
— Comitato Nazionale per l'Energia Nucleare (CNEN)	— Italy.

On the basis of the Venice scheme, this group was instructed to carry out the basic studies required for the compilation of a Euratom Economic Handbook, the aim being to gather all basic economic data relevant to the calculation of the nuclear power-generating cost, taking into account the existing conditions in each Community

State and in the Community as a whole, to consider the different techniques that can be applied and to propose a uniform calculation method. This work has now come to an end and the findings have been used into the compilation of this Euratom Economic Handbook. The Report of the Groupement is separately available in microcard form as an appendix to the present report.

At the same time, the Commission also obtained the first actual operating data of the first power reactors in which it had a financial stake. With a view to a proper assessment of the results gained from this Participation Programme, the Commission was very anxious to obtain a true calculation of the fuel cycle cost. It therefore engaged the Comitato Nazionale per l'Energia Nucleare (CNEN), by contract to evolve a method of calculating the fuel-cycle on the basis of actual operating data. This report was published in November 1965 (Document EUR 2521.e*).

Finally, a study was awarded at the beginning of 1966 to METRA International. The object of the study is to make a complete inventory of all taxes which directly or indirectly affect the power generating cost. The results of this study have been published in November 1967 (Document EUR 3639.f**).

The purpose of the present document is to formulate clearly the result of the studies completed to date, in the form of an unequivocal method for calculating nuclear power cost. The title Economic Handbook might be somewhat misleading. The idea is not to present an overall survey of all the economic features of the nuclear power cost calculation. What is essential is to present a method that can be applied whenever the need is felt to produce figures on the cost of the nuclear kWh which lend themselves to unequivocal interpretation.

The present document will therefore rely very heavily on the contents of the above-mentioned documents. Many analytical considerations available in those documents and in the literature in general will not be mentioned here. Only all the basic notions used and the method adopted to reach the desired result are restated in this document so that it can be used independently for practical application.

It is hardly superfluous to re-emphasize that it is not the purpose of this document to establish a valid criterion of the relative economic merit of different means of producing electricity, either by nuclear or by conventional techniques. It is confined to the elaboration of a method of calculating a power generating cost which will meet with general acceptance. This is the aim which the Euratom Commission hopes to achieve in publishing this Euratom Economic Handbook.

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* "Method of calculating fuel cycle cost on the basis of actual operating data" — Comitato Nazionale per l'Energia Nucleare, Rome, Italy, International Affairs and Economic Studies Division — Euratom Contract No. 009-62-11 ECII.

** "Incidence des régimes fiscaux en vigueur dans les pays de la Communauté sur l'économie des centrales nucléaires" — METRA INTERNATIONAL, Paris, Euratom-contract No. 028-66-2 ECIF.

1 — BASIC REFERENCE SCHEME

The following basic reference scheme is the outcome of the first Venice Symposium on The Technical and Economic Aspects of Proven-Type Reactors (October 1963).

1.1 — A priori and a posteriori costs

Before analyzing the factors making up nuclear power costs, it is necessary to state which cost is under consideration.

For a nuclear power plant in the design stage or under construction only an *a priori* cost can be calculated. Even if use is made of the best possible estimates, and certain appropriate safety margins are introduced into the calculations, they will inevitably involve approximations and uncertainties.

On the other hand, after the plant has been commissioned, and still better, after it has been in operation for a few years, it will be possible to calculate a cost based on real accounting data. This *a posteriori cost* will clearly be more exact and more realistic, but it will be difficult to compare it to the cost which was calculated a priori.

Whatever cost is calculated, a priori or a posteriori, it can be correctly interpreted only if the time factor is taken into account.

Every cost estimate must therefore indicate clearly the reference data upon which it is based. The a priori cost estimate must mention the date on which the estimate of the power design was drawn up, the scheduled commissioning date, and the reference date for the prices that have been introduced into the calculations. For the a posteriori cost, nominal expenditure must be introduced into the formulae as they actually occur. It will be explained later on in this document how to deal with expenditure scheduled for the future. The reason for earmarking carefully all expenditure and prices according to date is related to the need to identify afterwards, as clearly as possible, the influence of any variation in economic conditions on the one hand and the effects of technological progress on the other.

1.2 — Fixed costs and variable costs

One of the first distinctions to be drawn is that between *fixed costs* and *variable costs*. The former are independent of the quantities of energy actually produced, whereas the latter are related to it, either by a proportionality law or by other relationships which it is not always possible to formulate with mathematical exactitude.

The *fixed capital costs* are an essential component of the fixed costs. They represent the capital immobilization charges relating to the plant costs, including the moderator and the liquid coolant but excluding the initial fuel charge.

The *fuel costs* are subdivided into fixed costs, which result from the immobilization of the capital necessary for the fuel present in the fuel cycle, and variable costs resulting from the consumption of the fuel.

The staff costs, the consumption of maintenance material and spares, and the administrative costs do not in practice depend upon the amount of energy produced, although some of the *operating and maintenance costs* (e.g.: losses of organic moderator or heavy water) are variable.

Finally, the annual *insurance* premiums are by no means a negligible item. They are of course fixed costs.

The breakdown between fixed and variable costs is therefore as follows:

Fixed costs:

- Fixed capital costs:
  - plant
  - fuel charge
- Fixed operating and maintenance costs
- Insurance.

Variable costs:

- Fuel consumption
- Variable operating and maintenance costs.

These various cost components will be examined in detail further on.

2 — USE OF THE PRESENT WORTH METHOD

2.1 — The proposed method

Since the construction and operation of a nuclear power plant involve expenses which are spread over a long period of time, it is essential to use a method which is able to cancel out these time discrepancies. The most obvious method to be used in this case is the present worth method, also called the actual value method. As is well known, any sum of money existing in the future or in the past at a time t, is expressed in present-worth terms with respect to time t_0 by applying the factor $(1+i)^{t_0-t}$. The kWh produced at a given time t represents a certain value. This value also can be multiplied by the present-worth factor to express it in relation to the time t_0. Many values can be attributed to that kWh. However, where a cost is to be calculated this value should be replaced by a cost such that the total present-worth value of all kWh generated during the plant's lifetime is equal to a present-worth value of all expenditure and revenue (excluding however that deriving from the sales of this energy), stemming from the generation of that electrical power. The application of this principle thus leads to the following formula:

$$\sum_n \frac{CK_j}{p_j(1+r_j)} = \sum_n \frac{(E_j - R_j)}{p_j(1+r_j)}$$

where:

C = the total unit power generating cost
Σ = sum over the plant life, starting from the day the first expenditure was incurred until the end of the plant life (n)
j = the year considered
P_j = product of j factors of the type $1+r_j$
r_j = the interest rate for the j^{th} year
K_j = the number of kWh produced during the j^{th} year
E_j and R_j = expenditure and receipts in respect of the j^{th} year.

If the application of the present worth method does not give rise to any difficulties in practice once the data are available, the main problem remains the correct choice of the present worth interest rate.

In the above formula this rate is assumed to vary each year. This possibility is seldom used in practice, probably because it is already so difficult to select a *single* correct interest rate that a correct choice of an interest rate varying during each year of the plant's life seems to be completely out of the question. Consequently, all r_j will be assumed to be equal and this common value of r_j will be denoted by i.

As previously mentioned, the conversion of any sum at the time t to its actual value at the time t_0, where i is an annual interest rate, is effected by multiplying it by a factor $(1+i)^{t_0-t}$. t_0 and t must be expressed in a certain number of years. Theoretically, t_0 and t are not necessarily integers. However, published interest tables are generally designed for integral values of t_0-t. This means that the use of such interest tables presupposes that any sum of money in question is due at the end of an integral number of years. This is not so in reality and it is therefore preferable to divide the year into quarters or months. If necessary, the year could even be broken down into an infinite number of periods. This leads to the concept of continuous discounting, and it is well known that in that case the present worth factor becomes:

$$e^{\alpha(t_0-t)},$$

in which α = the continuous interest rate, which is related to i, the discrete annual interest rate, by the familiar formula:

$$\alpha = \log(1+i).$$

For practical purposes, however, it will be sufficient to divide the year into quarters. Appendix 1 of this report gives the present-worth factors for cases in which this quarterly approach is used.

Although the foregoing explains how to use the value i once it has been selected, nothing has been said yet about the choice of the value i itself. This will be discussed in the next section.

2.2 — Choice of the interest rate to be used for the present worth method

In order to simplify the terminology of the following paragraphs, the interest rate to be applied in the present worth method will be called simply the "present worth rate".

Basic theoretical considerations on the interest rate in general and the choice of this present worth rate at the firm's level in particular, are given in the Report of the Groupement (Part I, § 2.3 and 2.4, Appendix V) and in the literature in general. It is not intended to repeat these basic considerations in this document.

To sum up, it should be borne in mind that this present worth rate is influenced by the following factors:

— the cost of money in its various forms (stocks or bonds) on the capital market and the position occupied in this market by the industrial sector concerned;

— the juridical status of the firm and the fiscal system with which it must consequently comply;
— the financial structure of this utility.

All these factors will contribute to what can be called the cost of money for that particular firm. It is important at this stage to note that this cost of money already partly accounts for the losses incurred as a result of monetary depreciation. Indeed, the cost of money on the capital market normally follows—albeit with a certain time-lag and to a limited extent—the inflation for which the lender wishes to be compensated.

The financial department should be able to assess this cost of money in the light of the firm's financial and fiscal liabilities, though this will be a yearly *a posteriori* assessment based on the annual balance sheets. It also should be in a position to make a reliable estimate of the cost of money for the near future, and this estimate can then be used as a basis for determining the present worth rate.

This does not mean, however, that this cost of money should be taken as the interest rate for the present-worth method. In the first place, the payments of interests, taxes and dividends do not in practice conform with the simple compound-interest model upon which the present worth method is based.

Secondly, even if this were the case, the result for that firm would be that if its business decisions concerning price policy and investment programme are based upon such a present worth discount rate, this would lead to a somewhat static situation. On the one hand, the dynamic expansion of this firm would be severely limited, and on the other hand the firm would meet with serious difficulties in maintaining its industrial potential when it proceeded to make the necessary replacements, because no allowance would have been made for inflation.

It consequently becomes obvious that this present-worth rate is the outcome of the interplay between the cost of money (itself a very complex result of the above-mentioned factors of influence), the profitability objectives that this firm wants to pursue and, finally, its desire at least to maintain its industrial potential in view of the permanent inflation with which it is confronted.

This leads ultimately to the conclusion that the present-worth rate results from a management decision. Their responsibility is such that all decisions based upon these present-worth calculations enable the firm to fulfil all its financial obligations (interest payments, taxes and dividends), to ensure a dynamic growth compatible with the expansion of the market in which it is operating, and to maintain its industrial potential despite the permanent monetary inflation.

In the particular case of calculating the cost of power generation it seems advisable at the present time to choose a present-worth rate of between 6 and 9%, 7% being considered a good representative figure.

Two important comments are called for here:

— two power-generating costs calculated on different present-worth rates should be handled with care as far as their comparability is concerned. It must not be forgotten that the compound-interest model upon which the present worth method is based is only an approximation of reality;

— obviously, the present-worth interest rate will differ from one country to another and possibly from one utility to another. However, the difference between utilities in a given country operating under theoretically similar conditions, will be virtually negligible in practice, because they occupy similar positions on the capital market and possess similar financial structures. Their long-term policies cannot differ so fundamentally as to lead to appreciably different present-worth interest rates for power-generating cost calculations. This means that for a given country we can rely upon a single representative present worth discount interest rate.

2.3 — Practical application of the method

Having chosen the present-worth rate and divided the year into quarters, we should now be in a position to apply the correct conversion factor to each of the expenses or receipts, taking into account the time at which they occur. The same can be said of the conversion of the generated kWh to actual value.

When the *a priori* cost of a nuclear project is calculated, or even when the *a posteriori* cost of power generation by plant in actual operation is calculated, two problems arise in the determination of the time-schedule and the amount of expenses and receipts, and in the determination of the energy produced.

The first problem is that of predicting the load factor of the plant. This point will be discussed in the next chapter. It must be solved, since the flow of money is directly related to the output of the plant.

The second problem encountered is what part of the future flow of money will be influenced by the general price inflation. Any amount, the nominal value of which is unalterable, either because the relevant transaction has already taken place or because this amount is contractually fixed for the future, does not present any difficulty and is introduced as such into the calculation.

Nevertheless, corrections should be made in order to take account of the effect of price inflation on alterable future money transactions. To account for this inflation is probably, at least at the present time, an insoluble problem. It is obvious that the yearly inflation rate varies from one country to another, and in a given country from one year to the next. Its impact differs from one industrial sector to another. It is not sufficient to take price indexes as an expression of this phenomenon. Prices of industrial goods are also influenced by:

— the productivity in the manufacturing processes
— the equilibrium of supply and demand on the national and the world market

— technological progress
— more general economic factors such as the overall business climate, the foreign-trade policy of the industrial nations, the development of new techniques which can replace existing ones, the discovery of new resources, etc.

All these factors, together with monetary depreciation, have different and sometimes contradictory effects, so that it is very difficult to foresee what the actual price levels will be either in the near or the more distant future.

If we take the very simple hypothesis that monetary depreciation is the only factor affecting the price levels and that the rate of depreciation is constant over the years, a future expense or receipt can be predicted from the formula

$$S = S_p(1+r)^t$$

in which S_p is the amount based on current prices, r is the constant annual depreciation rate and S is the nominal amount of that expense t years from now.

Conversion of this amount S to present-worth using the rate i which takes account of monetary depreciation as explained above, leads to the following value:

$$\frac{S}{(1+i)^t} = \frac{S_p(1+r)^t}{(1+i)^t} = \frac{S_p}{(1+i-r)^t}$$

which in fact means that the present worth rate has been corrected by subtracting its monetary depreciation component.

Which value must be chosen for this depreciation rate is difficult to suggest. The average depreciation rate often mentioned for Western Europe in recent years is of the order of 3% p.a., but as far as we know there are no published studies which give the scientific justification of this generally accepted figure.

For certain expenses such as labour, which will be part of the operating and maintenance cost, the full impact of this monetary depreciation rate could be introduced into the calculations. For other items, in respect of which the economic conditions and technological progress are the main factors determining the price level, it should be borne in mind that this monetary depreciation rate is partly or even wholly offset by the incidence of these factors. Consequently, the value of r for these expenses would be less than 3% per annum, or even 0, and in certain cases would take on a negative value.

As a practical conclusion the following procedure could be suggested:

1. For past expenses and receipts, use the chosen present worth rate without modification.
2. For *future* expenses and receipts based on the current prices, which can vary both as a result of technological progress and fluctuations in the economic conditions, and owing to monetary depreciation, the *uncorrected* present-worth interest rate should be used. This assumes in fact that future technological progress and general economic conditions will at least compensate for the monetary depreciation.

Obviously, if future prices are already known at their nominal value they should be introduced into the calculations at their nominal value as known today.

3. For *future* expenses in respect of which the price evolution depends mainly on monetary depreciation, the nominal values based on the actual prices should be used, but they should be converted by means of a *corrected* present worth rate.

On the hypothesis that the yearly monetary depreciation rate can be accurately assessed and the resulting corrections are effected, as explained above, we have a power-generating cost based on actual prices at the time t_0 taken as a reference point. Theoretically, it can be accepted that past expenses have been corrected by the built-in influence of monetary depreciation by way of the present worth interest rate, which has taken this aspect into account. Future expenses also have been readjusted to the conditions prevailing at the time t_0.

In practice, however, the corrections suggested above under 3, which relate to a comparatively small fraction of the expenses concerned, are such a rough approximation to reality that the question arises whether it would not be advisable simply to use the *uncorrected* present-worth discount rate, as determined under 2, for all expenses, both future and past. It is therefore this solution which is finally recommended for the further application of the present worth method.

3 — BASIC ECONOMIC PARAMETERS

In order to calculate the power generating cost, using the present-worth method as explained in the previous chapter, certain basic economic parameters must be determined. If the circumstances do not dictate the value of such parameters unequivocally then a judicious choice must be made.

These parameters are:

1. the interest rate applied in the present-worth calculations
2. the reference date
3. the plant life
4. the load factor
5. the nominal power.

3.1 — **The present worth rate** as an economic parameter was thoroughly discussed in the previous chapter. Let us recapitulate that its choice results from considerations related to the cost of money on the capital market, the utilities position on this market and its profitability objectives, and to monetary depreciation and expected technological progress trends. Once the choice has been made, it will be assumed that all these aspects of the power generating cost have been accounted for, and no additional corrections will be introduced in view of one of these context factors.

3.2 — **The reference date** to which the present values pertain by the application of the present-worth factor $(1+i)^{t_0-t}$, will be 1 January of the year in which the commercial operation of the plant has begun (a posteriori cost) or is scheduled to begin (a priori cost). The results of the calculations are representative of the economic conditions prevailing at the time t_0. This should be borne in mind, as already pointed out in the previous chapter, when the calculated power generating cost is compared to that of other plants referring to different dates.

3.3 — **The plant life** is the time interval between the beginning of the commercial operation of the plant and the time at which the operation of the plant, even as a reserve unit, is no longer justified. For the sake of uniformity, the plant life will be considered as lasting from t_0 to 31 December of the year in which the plant ceases operation (t_z). The determination of this time-lapse involves an evaluation of long-term power production and power demand expansion. The fiscal conditions can be the decisive factors, so that it is known for certain that after t_z the plant will still be operated. However, energy produced after t_z and the expenses connected with the production of this additional energy are not accounted for a priori. The analysis is based on the assumption that operation ceases and the plant is dismantled. Recovery of final credits may of course occur after t_z.

The following are some numerical values adopted at present for nuclear plant life in the Community:

Belgium	20 years
Federal Republic of Germany	17 years
France	30 years
Italy	25 years
Netherlands	15 years.

3.4 — The load factor, expressed as the number of equivalent operation hours per year at nominal power, varies over the life of the plant. It is in the first place dependent upon the plant availability factor. Since plants in an interconnected system contribute to satisfying the power demand in ascending order of their variable production costs, any new addition to the system, nuclear or conventional, will at the beginning of its life operate at base load. However, since the nuclear plant has lower variable production costs, it will remain on base load during a larger number of years than a conventional plant.

It is very difficult to predict how the load factor will vary in time for a plant installed at a given time. It depends on the development of the electricity demand and of the structure of this demand as well as on the investment decisions that will ultimately be taken to meet the anticipated future evolution. A decisive factor for estimating the future load factor of a given plant is the type of new plants that will be installed later on. Considerations concerning this problem are developed in the Report of the Groupement and an optimization model for the load factor is dealt with in the annex 3 to this Report.

In view of the complexity of the problem, and consequently the doubt that might arise concerning the validity of the results of a mathematical analysis, it seems quite reasonable to adopt, for *a priori* power generating cost calculations, an average constant load factor, for instance 6000, 6500 or 7000 hours per year.

For a posteriori calculations, of course, the power actually produced in the past will replace the a priori estimate previously adopted, while for forecasting purposes an average constant load factor estimate must be maintained in the calculations.

3.5 — The nominal power is the net available electrical capacity on the high-voltage side of the transformer. It is thus the power actually available for supply to the grid, after deduction of the gross capacity of the requirements of all the plant auxiliaries.

A stretch-out capacity is often provided for. Unless the time at which this stretch-out capacity will be used is known it will not be taken into account in a priori cost calculation. For a posteriori calculation, this stretch-out capacity has no importance for the energy already produced. As far as the future energy production is concerned, this stretch-out capacity is taken into account if it has already been used, or if the time at which it will be used is known for certain.

4 — PLANT COSTS

One of the most important components of the nuclear power generating cost is the annual capital cost, i.e. an item which is based directly on the total capital investment required on the part of the utility up to the time of the power plant being brought into service. The major part of the capital cost is related to the plant cost, which includes by definition all expenses incurred to make the plant operable, excluding however the initial fuel load and reserve.

The date on which the plant is brought into commercial operation after a certain period of start-up trials shall be chosen as the reference date for establishing the plant cost. However, when the present-worth method is used to calculate the total plant cost, the rules set out in Chapter 3 shall be observed. All calculations will therefore refer to 1 January of the year in which the plant starts commercial operation.

According to the distinction of *a priori* and *a posteriori* cost which has already been introduced, two different methods of plant cost evaluation are proposed.

4.1 — The a priori plant cost

The *a priori* cost is the one which will be taken into consideration when the decision to construct a nuclear power plant has to be made, so that this concept is of some importance.

This concept can, of course, be correctly interpreted only if the reference date is known. Every *a priori* cost estimate must therefore indicate clearly the date on which the power-plant design was established as well as the scheduled commissioning date. This information is essential to interpret the technological status of the plant's conception. Further, in order to cancel out the inflation factor, the prices which have been introduced in the calculations must be those prevailing at a given time, of which mention must also be made.

If it is desired to draw a distinction between direct and indirect costs, differences will arise in the meaning of the distinction from case to case.

When the operator decides to go ahead with the construction of a nuclear plant, he may proceed in various ways.

Sometimes the operator himself assumes responsibility for design and construction. This does not prevent him farming out all or part of the design study to specialized firms or organizations under contract. He makes separate contracts for the construction and ensures their coordination (e.g. Électricité de France). Other companies have chosen the "turnkey" formula by which a supplier's group undertakes both the design and the construction of the project. The operator merely puts at their disposal a site equipped with certain on-the-spot facilities specified in the contract, and carries out constant acceptance testing (e.g. German utilities).

Between these two extremes there is an intermediate formula by which the operator undertakes various engineering studies and the direct negotiation of sub-contracts, whereas one or more contracts, which might be termed basic contracts, are awarded to a limited number of suppliers.

From the preceding remarks it is clear that if the total amount accounted for by design study and supply contracts is considered as plant costs, the figures obtained for direct and indirect cost are not strictly comparable. Engineering costs and overheads are incorporated in various ways, depending on whether they are borne by the suppliers or by the operator himself.

Keeping this difficulty in mind, the following investment cost classification system has been compiled of the factors which go to make up the initial capital expenditure for the power plant, a distribution being made between direct and indirect costs.

1. — Direct costs*

Account Number

10 **LAND PURCHASE AND GROUND TESTS**
(Normally owner's direct responsibility)

1. Land Purchase
2. Land rights and rights of way
3. Clearing of land, including demolition
4. Relocation of traffic ways, water and sewage lines, power and telephone lines, etc.
5. Surveying
6. Ground investigations and test drills.

11 **SITE DEVELOPMENT AND SUPPLIES DURING CONSTRUCTION***
(Normally the responsability of the operator; not provided for in a turnkey contract for the construction of the station)

1. Access roads to site for permanent use and maintenance during construction
2. Access rail-spurs to site and unloading facilities

* If the site is not yet known, these direct costs can be established for a hypothetical site described in Appendix 2 of this Report.

Account Number

3. Temporary and permanent unloading facilities at site for water transport
4. Draining of land around the site
5. Transmission line and H.V. sub-station for electric al powersupply during construction
6. Temporary and permanent water supply system
7. Supply of electrical power and water during construction
8. Temporary buildings at site under owner's direct responsibility.

12 **CIVIL WORKS**

All civil works normally covered by a turnkey contract for construction of the station (mainly within the fenced area).

121 **Buildings**

(separate series of accounts for each major building, minor building groups) All buildings of the station including reactor building (except pressure-tight containment structures), power house, electrical annex building, reactor auxiliary buildings, c.w. intake and pump-house, self-supporting stack, workshop, stores, administration building, porter's lodge, etc.

. 1 Excavation and backfill, sheeting and shoring, draining

. 2 Bearing piles and caissons respectively or other methods of foundation

. 3 Substructure concrete, including shuttering, reinforcing, concrete, waterproofing, insulation, finish, anchorbolts, sleeves and other embedded steel, etc.

. 4 Superstructure, rough work, consisting of all concrete, exterior walls, all brick-work; structural steel including ladders, stairs, platforms, etc., roofing and flashing

. 5 Superstructure, finish work, interior masonry and partitions doors and windows, wall and ceiling finish, floor finish, glazing, insulation and painting, special protective coatings for easy decontamination

. 6 Stacks supported by buildings

. 7 Building services:
Plumbing and drainage systems, heating and ventilation systems*, air conditioning systems*, elevator structures, lighting and service conduit and wiring fire protection system inside building

. 8 Workshop buildings (See Appendix 2)

. 9 Store for spare parts and shop materials (See Appendix 2)

.10 Hot workshop buildings

.11 Fuel inspection laboratories

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* If not part of a centralized system for the reactor area with main equipment in a special building, see account No. 134.

Account Number

122 **Reactor Containment Structure**
(only if existing)
Pressure-tight containment structures, such as spheres or cylinders, which are designed to contain the products of an uncontrolled release of reactor coolant from the reactor cooling system.
.1 Excavation and backfill
.2 Bearing piles or caissons
.3 Substructure concrete
.4 Superstructure, rough work including containment shell and airlocks, structural steel supports, all concrete and brickwork, etc.
.5 Superstructure, finish work including floor, wall and ceiling finishes, doors, exterior insulation and protection of the containment shell, interior finish of the containment shell
.6 (Reserved)
.7 Building services
same as 121.7.

123 **Site improvements**
.1 Levelling, grading and landscaping
.2 Temporary and permanent roads and parking areas at site
.3 Rail tracks and accessories at site
.4 Temporary buildings (workshops, stores, canteens, offices, labour camp, etc.) if not included in equipment supply contracts
.5 Temporary and permanent fencing
.6 Electrical power and water distribution systems for the construction period
.7 Temporary and permanent drainage and sewage systems (See Appendix 2)
.8 Permanent drinking and service water distribution systems outside the buildings, including fire protection system
.9 Outdoor lighting.

13 REACTOR PLANT EQUIPMENT

131 **Heat generating plant**
Reactor vessel with supports and structural internals, moderator and reflector, shiedling, control rods with drives, auxiliary cooling and heating facilities, cranes and hoists.
.1 Reactor pressure vessel,

shop-manufactured or site-welded metallic pressure vessel with head, bolts, nozzles, standpipes and covers, etc., without internals,
or,
prestressed concrete pressure vessel with vertical and horizontal concrete, including prestressed cables and anchorage, duct inlets and fuel channel inlets, without lining and internals,
or,
pressure tube vessel, pressure tubes with sealing plugs only, without internals as insulating tubes, shielding plugs, etc.

.2 Pressure vessel supports

.3 Pressure vessel structural internals
all structural elements inside the pressure vessel (or integral with the vessel for pressure tube design) for core support, moderator support, reflector support, coolant flow shrouds and throttles, thermal shielding and insulation, internal biological shielding, etc.
especially:
vessel lining for prestressed concrete pressure vessels including cooling tubes, coolant headers and radial thermal neutron shield for pressure tube vessels

.4 Moderator and reflector (if not identical with coolant liquid only)*
For solid moderator and reflector:
all active elements and parts including cladding (if any) and directly connected structural parts, as belts, girders, etc., and embedded instrumentation, but without support grid (in 131.3)
For liquid moderator and reflector:
moderator and reflector liquid (e.g. heavy water), moderator tank with accessories.

.5 Local reactor controls
control rods including absorber sections, housing, guide tubes and shrouds, drive mechanisms including power accumulators and position control transmitters, hydraulic, pneumatic and electrical supply system for rod drives including controls, service and maintenance facilities for control rods, supplementary control systems, neutron sources. If no absorber rods are used for control (e.g. moderator level control in case of liquid moderator) the analogous equipment is understood under this heading

.6 Reactor shielding

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* If identical with coolant liquid, it is charged under account No. 132.5.

(if not already part of civil work account Nos. 121 and 122 or part of account Nos. 123.1 to 3
thermal neutron shields including shield tanks, biological shield, cooling coils, blast shield

.7 Refuelling equipment
Fuel charge and discharge tools and machines for fuel change under shut-down or on-load conditions, including travelling facilities, auxiliaries and local controls, inside the station emergency discharge facilities.

.8 Reactor auxiliary process systems
.81 Safety injection system
.82 Emergency shut-down cooling and decay heat removal systems
.83 Shield cooling systems
.84 Moderator purification and regeneration system, cooling system, inert gas system and storage and discharge facilities for liquid moderators
.85 Filling, evacuating, cooling and flushing systems for refuelling machinery
.86 Component cooling system (intermediate cooling system)
.87 Post-incident cooling system and pressure suppression system
.88 Miscellaneous other equipment
Equipment of all systems complete with tanks, filters, pumps, blowers, compressors, drivers, heat exchangers, etc. but without pipework, valves and control equipment
.89 All pipework and valves for equipment under account No. 131, including hangers, supports, valve drives, insulation

.9 Fuel element failure detection equipment
Piping, selector valves and complete sampling units with local electronic equipment.

132 **Heat transfer and steam generating plant**
Main coolant system and, if any, intermediate coolant system, with main coolant piping, valves, pumps, blowers and steam generators (for direct cycle without the corresponding items), and auxiliaries for coolant charging and discharging, pressurizing, purification, sampling, intermediate storage, etc.

.1 Reactor coolant system
.11 Pumps, blowers and drives including auxiliaries and local control boards (variable frequency turbogenerators see number 141)
.12 Coolant piping and valves including hangers, supports, bellows and valve drives with local control, insulation
.13 External steam drums and separators when integral with reactor coolant system for direct cycle water reactors

.2 Intermediate coolant system
  .21 Pumps and drives
  .22 Piping and valves, insulation
  .23 Intermediate heat exchanger
.3 Nuclear steam generators and superheaters
  Boilers with economizer, evaporator, steam separators and superheater, if any, for drum type boilers including steam drums and circulating pumps including all integral piping and supports. Separate superheater, if any
.4 Reactor coolant supply and treatment for intermediate coolant too, if any
  .41 Charge, volume control, pressurizing and relief systems
  .42 Drying, filtering, purification and trap systems
  .43 Coolant receiving, storage, make-up, transfer and blowdown facilities
  .44 Coolant sampling system
  .45 Inert gas system
  .46 All piping and valves, thermal insulation for 122.4
  .47 Coolant fabrication, if on the site
.5 Initial charge of coolant (including recoverable coolant such as D_2O and He); if serving as both coolant and moderator it is charged to this account
.6 Conventional fuel fired superheater, if any.

133 **Nuclear fuel handling and storage equipment**
All facilities for storage, inspection, package and transport of new fuel and irradiated fuel, but without reactor fuel charging and discharging equipment under cost account 131.7
.1 New fuel store equipment:
  store racks, inspection facilities, store hoists and transport facilities
.2 Packing machinery, hoists and special transportation equipment for transport of the irradiated fuel to the storage facility inside the station
.3 Cooling plant with heat exchangers, circulating and filtering equipment, pipework, etc.
.4 Storage of irradiated fuel on the site
  a) for temporary storage prior to off-site transport to a collecting store or to the reprocessing plant
  b) for the discharge of a whole reactor capacity.

134 **Reactor area heating and ventilating plant**
If not within building accounts 121.7 and 122.7 only complete heating, cooling and ventilating plant for reactor building and reactor auxiliary

buildings, with filters, fans, heaters, coolers, refrigeration plant, filter handling facilities, ducts and valves, sampling system and control equipment, Inert gas generating equipment, if an inert gas atmosphere is needed.

135 **Radioactive waste treatment and disposal**

.1 Waste treatment plant for gaseous and liquid effluents and burnable solid waste complete plant with filters, separators, storage and monitoring tanks, ion exchangers, evaporators, pumps, blowers, pipework and control equipment, drumming and packing facilities, incinerators with filter and washing plant, etc.

.2 Station temporary storage plant for liquid and solid wastes (See Appendix 2, p. 83)

.3 Waste transport facilities for transport to central waste stores, if any.

136 **Decontamination and maintenance equipment**

.1 Equipment decontamination system with decontamination tanks, chemical mixing tanks, rinsing tanks, drying and control equipment

.2 Other special maintenance equipment for the reactor plant, if installed.

137 **Instrumentation and Control**

All measuring, control, alarm, protection, monitoring and data-processing equipment for the reactor plant, heat transfer system including the steam generators, and all auxiliary systems, except the local instrumentation and control equipment already covered by account Nos. 131 to 136.
Complete with sensors, transmitters, amplifiers, instruments, recorders, power supplies, protection and alarm relays, local boards, control boards and desks for the control room, auxiliary boards, wiring and cabling, instrument piping and tubing, including cable penetrations through the reactor containment and pressure vessel.

138 **First Fillings**

First fillings of grease, oil, filter materials, etc. for the equipment account Nos. 131 to 137.

14 TURBINE-GENERATOR PLANT

141 **Turbine-Generators**

Complete turbine generator main set (and auxiliary sets: for instance variable frequency turbo-generators, if any) with all auxiliary equipment as lubricating and control system oil tank and coolers, standby oil pumps and drives, turning gear, main stop and reheat valves, all integral piping, thermal insulation, local control equipment and instrumentation including local panels, generator coolers, hydrogen equipment, CO_2-extinguishing system, shaft driven main and pilot exciters, voltage regulator and excitation equipment.

142 **Condensation Plant**

Complete condenser, condensate pumps and drives, vacuum pumps or ejectors respectively, condenser supports, condenser protection, steam dumping device with injection system, cold condensate tanks and other tanks belonging to the condensation plant, integral piping. Air condensing plant also under this account No. 142.

143 **Feed water heating and supply system**

.1 HP- and LP-feed water heaters, feed water tanks de-aerators, pressure reducing and control valves, feed heater water level control equipment, auxiliary pumps

.2 Feed-water pumps and drives including all auxiliaries.

144 **Steam, condensate and feed-water piping**

.1 All piping and valves for the steam power generating equipment including main and auxiliary steam lines from the reactor or steam generator to the turbine, cold and hot reheat steam lines, turbine extraction lines, condensate and feedwater piping, h.p. and l.p. drains and vents, drain collecting tanks and associated equipment and all other miscellaneous auxiliary steam, drain and vent lines of the reactor or steam generator respectively, the turbine, condenser, feed heaters and feed pumps

.2 Thermal insulation of piping and valves for account No. 114 and feed-water heating and supply system account No. 143.

145 **Water Treatment Plant**

.1 Raw water supply system including storage facilities

.2 Make-up water supply and coarse treatment systems, including storage facilities

.3 Feed-water treatment and storage facilities

All systems complete with integral piping, valves and local control equipment.

146 **Circulating Water System**

Complete main and auxiliary circulating water system including water supply and facilities and cooling towers

.1 Pumping equipment, pumps, drives and controls, screen cleaning equipment, coarse and fine screens, cranes and hoists
.2 Cooling towers and cooling ponds, complete with structure shell, foundations and basin, water distribution and spraying system, integral piping, fans and drives with auxiliaries
.3 Main and auxiliary circulating water, piping and valves including main c.w. lines (steel and concrete)

Not under this item are only closed c.w. systems of the reactor plant.

147 **Turbine plant boards, instruments and controls**

Turbine plant control system, including panel mounted supervisory instruments and controls, control boards and panels, isolated controllers, recording gauges, meters and instruments, inclusing complete cabling and wiring. Not included the local instrumentation of the turbine and the electrical instrumentation of the generator and exciters.

148 **First fillings**

First fillings of grease, oil, filter materials, etc. for the equipment account Nos. 141 to 147.

15 **ELECTRICAL EQUIPMENT**

All electrical equipment of the station including the generator step-up transformer and start-up transformer, but except H.V. sub-station and the instrumentation and control equipment already mentioned under cost account Nos. 13 and 14, lighting and intercom systems.

151 **Main transformer**

Single or three-phase step-up transformers including cooling plant and oil filling.

152 **Station service equipment**

Voltage conversion and regulating equipment for station service and lighting, station batteries and charging equipment, emergency power equipment
.1 Transformers and voltage regulators
.2 Batteries and charging equipment
.3 Emergency Diesel sets and motor generators.

153 **H.V. Switchgear**
.1 H.V. switchgear, busbars, voltage and current transformers of generator main and neutral circuits including busbar connection to the L.V. terminals of the main transformer primary windings
.2 H.V. switchgear of station and unit auxiliary power systems.

Account Number

154 **L.V. Switchgear**

.1 Three-phase L.V. switchgear and motor control centers of the auxiliary power systems

.2 D.C. switchgear and D.C. auxiliary boards.

155 **Station protective equipment**

.1 General station grounding system

.2 Fire protection systems exclusively for electrical equipment account No. 15.

156 **Control, alarm and relay protection equipment**

Main control room desk and panels for the generator and auxiliary power systems, relay protection equipment with relay boards, meter panels alarm and tripping panels and other auxiliary panels.

157 **Cables and cable structures**

.1 Main and auxiliary power cables, excitation cables

.2 Control and instrumentation cables (except those already part of the control and instrumentation equipment under account Nos. 13 and 14, lighting wiring account No. 12 and cabling of intercom systems)

.3 All steel structure, cable trays and supports for cabling and wiring of the whole station.

16 AUXILIARY POWER PLANT EQUIPMENT

161 **Cranes and hoisting equipment**

Cranes and hoisting equipment for general station use, except reactor plant and fuel handling cranes, see account No. 13

.1 Turbine house crane

.2 Other cranes and hoists

.3 Passenger and cargo lift, electrical and mechanical equipment.

162 **Auxiliary boiler plant**

.1 Packaged boilers for heating and auxiliary steam generation

.2 Fuel oil storage plant.

163 **Other power plant equipment**

. 1 Local communication, signal and call systems

. 2 Oil purification plant

. 3 Equipment of electrical and mechanical workshop

. 4 Equipment of instrument and electronics workshop

Account Number

. 5 Fuel inspection laboratory equipment
. 6 Hot workshop equipment
. 7 Compressed air vacuum cleaning systems including piping
. 8 Laboratory equipment and weather instruments
. 9 Mobil fire extinguishing equipment
.10 Lockers, furniture and fixtures
.11 Diesel oil storage plant
.12 Auxiliary fluid pipe system and wells for process and drinking water.

17 INITIAL SPARE PARTS

.1 Initial spare parts for reactor plant — Account No. 13
.2 Initial spare parts for turbo-generator plant — Account No. 14
.3 Initial spare parts for electrical equipment — Account No. 15
.4 Initial spare parts for station auxiliary equipment — Account No. 16.

2. — Indirect costs

Account Number

20 **Engineering, design and inspection**

201 Architect-engineer design services, preliminary investigations; dispatch, inspection and procurement of materials and equipment; inspection of construction work to ensure compliance with plans and specifications; engineering consultant services; engineering supervision in connection with construction work.

202 Nuclear engineering and design services for the reactor plant and auxiliary systems, including core physics analyses, reactor systems design, reactor hazards evaluation, license application and procurement, initial radiological site-surveys, and related items.

203 Operator training.

21 **Overheads during construction**

211 Job supervision (whether incurred by the owner, or accrued for the owner's account by the contractor)

.1 Administrative
.2 Field engineering
.3 Field superintendency
.4 Accounting
.5 Purchasing
.6 Personnel
.7 Security
.8 Office supplies and expenses.

Account Number	
212	Office furniture and fixtures.
213	Labour costs
	.1 Payroll, taxes and insurance
	.2 Workmen's transportation and subsistence allowances
	.3 Contributions to welfare schemes
	.4 Vacations, signing-on and severance pay
214	General expenses
	.1 Medical and first aid
	.2 Safety
	.3 Guards and watchmen
	.4 Contract fee.
215	Comprehensive insurance (including nuclear insurance) during construction.
22	**Contingencies**
23	**Power plant operation cost during trials (- receipts for the power generated during this period if any)**
24	**Interest during construction**
241	on capital borrowed
242	on owner's invested capital
25	**Price revision** (escalation)
26	**Taxes (other than payroll) during construction**
27	**Customs duties**

If plant costs are worked out on the basis of the classification system recommended here, a comparison of *a priori* costs of different projects becomes more significant. Nevertheless, taxation practices in the member countries of the European Community differ so widely that due allowance has to be made if projects are not compared within one and the same country.

Direct plant costs, for instance, are normally based on prices, which include all *taxes* and acquisition costs to be paid either by the supplier or the customer. In special cases (France) the taxation system makes it possible to account taxes separately, they are paid provisionally by the present customer but subsequently refunded by the following one. In the case of electric power, the utility pays the taxes, which are charged afterwards to the final consumer. In this case, direct plant costs which do not include taxes are not comparable with those which result from a sales tax system.

Moreover, attention has also to be paid to the incidence of customs duties, which will depend on the percentage of imported supplies.

Detailed data concerning different tax and customs rates obtaining in the different Member States of the Community have been published by EURATOM (contract with METRA International mentioned on page 4).

On the other hand, indirect plant costs generally include taxes due during construction, an item which may also comprise taxes on the capital (proper and borrowed) invested before the plant comes into operation (Germany).

A final important remark concerns item 25—*Price Revision*—of the indirect costs. Although this account is useful for estimating the total amount of money that has to be spent, its introduction results in a cost figure that cannot be related to any specific reference date, neither the year when the project was elaborated nor the year of commissioning. If one is interested in comparing afterwards the a priori cost with the a posteriori cost, this should be kept in mind. In order to ensure comparability appropriate corrections may probably be necessary.

The best figure to use for comparing plant costs is the specific plant cost. The figure is calculated by dividing the total plant cost by the number of installed kilowatts net (as defined in Chapter 3) of a given power plant. It is recommended that this specific plant cost be taken as one of the basic elements for an a priori comparison of nuclear power plants.

4.2 — The a posteriori plant cost

Whereas an *a priori* cost evaluation method should help the investor in his investigation of the best way of producing low-cost electricity the *a posteriori* cost evaluation can help the operator to verify the decisions which he made earlier, to check on current profitableness and to establish a price policy on the basis of the exact and realistic plant conditions.

Since in the case of an *a posteriori* cost evaluation the precise amount of all expenditures is known, as well as the date on which they were incurred, the method "par excellence" for establishing this plant cost is the "PRESENT WORTH METHOD" proposed in Chapter 2 of this document.

As already mentioned the time t_0, i.e. the date at which all the capital amounts invested are actualized, shall be 1 January of the year in which the plant was taken into regular service.

As opposed to the *a priori* method, however the classification system of the different plant cost items has to be modified, for several reasons:

a) The distinction between direct and indirect plant costs is no longer meaningful, since the method includes at one and the same time the cost of money during construction, for direct costs as well as for certain items of the indirect costs.

b) The cost items with the following account numbers in the "a priori" classification system are:

— superfluous

22 Contingencies

25 Price revision: by the present-worth interest rate prices are implicitly corrected to the date t_0—taken into account by fixing the "present worth rate"

24 Interest during construction

26 Taxes during construction insofar as they are strictly related to capital immobilization. Moreover, new cost items have to be considered.

The power station operation cost during trials (acc. number 2.3 in the *a priori* classification system) could be offset partially by the credit for energy produced before the commercial operation of the plant, which must now figure in this account.

At the end of its life the plant is dismantled. The possible expenditures or earnings related to this procedure have also to be taken into account in calculating the power generating cost and the plant costs under consideration here. This figures under a separate account No. 108: Plant dismantling costs and receipts.

As indicated in Chapter 2, § 2.2, the "present worth rate" which should be applied to the calculation of the plant costs, has to be fixed individually for each plant. Therefore, a comparison of the plant cost of two installations on the basis of the actualization method with a different present worth rate is scarcely possible.

5 — FUEL CYCLE COSTS

5.1 — General introduction

The fuel cycle cost of a nuclear power plant differs from that of a conventional thermal plant in two major respects. The first is that a considerable amount of money is usually tied up by being invested in the fuel of the nuclear plant and its associated facilities. This money is not only accounted for by routine expenses in proportion to energy production, as is the case with conventional thermal plants, but its composition is of a far more complex nature owing to the fact that it covers not only a complete series of distinct expenditures necessary for the provision of fuel of the appropriate quality and quantity to ensure scheduled reactor operation, but also a number of expenditures and credits relating to post-irradiational operations on discharged fuel loads. Finally, it would be quite unrealistic to define fuel cycle cost as the algebraic sum of fuel expenditures and fuel credits, since a series of the fuel expenditures and credits outlined above is spread over a considerable period of time. In order to attach the appropriate significance to this time factor, all sums of money, whether debits or credits, as well as energy produced, should be weighted in accordance with the date they become effective. This means that the present worth method should also be adopted for the fuel cycle cost.

Secondly, once a conventional thermal plant has been built and is in operation, its operational characteristics and related specific and total fuel consumption will not be subject to any fluctuations other than minor, negligible ones. An inherent feature of a nuclear power plant, on the other hand, is its ability to keep step with technological progress in that it is possible to vary its core characteristics and hence its fuel schedule. By virtue of this technological flexibility, the plant operator can make good use of the latest technological developments, thus achieving cheaper power generation, but at the same time fuel cycle cost calculations and estimates are complicated considerably.

For the two reasons discussed above there are many different methods of calculating nuclear fuel cycle costs. For the same reasons it is possible to state, within certain limits, that for a given reactor there are as many specific fuel cycle costs (i.e., fuel cost per u.s.o. = unit sent out) as there are calculation methods. Consequently, the calculation method chosen will to a large measure depend on who is handling it, whether it is the organization that draw up the design or the manufacturer who is building it or the electricity producer who is considering purchasing it.

The purpose of the calculation procedure described below is that it can be applied generally and will yield such results that their significance is precisely known and are of common interest. This is because it is based upon an accurate definition of a well balanced calculation scheme, so that different fuel cycle costs for one reactor, or fuel cycle costs for different reactors, can be compared on an equal basis either in the design stage or during operation. It is because of this latter aim that two fuel cycle costing methods must be considered:

a) An *a priori* cost evaluation method, to be discussed in this chapter.

b) An *a posteriori* cost evaluation on the basis of actual operating data, for reactors already commercially producing electricity. A description of this method has been published separately as a Euratom report EUR 2521.e: "Method of calculating fuel cycle cost on the basis of actual operating data", mentioned above. With this method the effective fuel cycle cost of nuclear power plant already in operation can be adequately determined for any given period and at any desired moment.

The method mentioned under *a*) not only permits the determination of a well-defined "*a priori* fuel cycle cost" so that different nuclear power plants can be compared at the design stage, but also enables an economic comparison to be effected, with regard to different possible future fuel management programs, for a power plant already in operation. In the latter case use can possibly be made of data already provided by the earlier application of the *a posteriori* method mentioned under *b*) to this same plant or type of plant.

5.2 — General principles of the method

From a practical point of view, the life of a nuclear plant can be divided up into four different periods, according to plot *A* in Fig. 1:

5.2.1 A construction period, which starts when the decision is taken to build the nuclear power plant and ends when the reactor goes critical. In accordance with the time schedule *F* in Fig. 1, the dates are indicated by t_c and t_s respectively.

5.2.2 A running-in period ($t_i - t_s$) according to *F* in Fig. 1 (page 91). This period is that elapsing between the time the reactor first went critical and the time the reactor core can be regarded as having entered the equilibrium stage. During this period fuel expenditures and fuel credits are still unequally distributed in time and are of varying magnitude. There is no logically acceptable proportionality as yet between the electrical energy produced per unit time and the fuel cost per unit time. The length of this period is, however, approximately inversely proportional to the average load factor.

This "running-in" period, though determined technically, is based on economic considerations. Nuclear plant life is for the moment generally accepted as being between 20 and 30 years. Total fuel cycle cost optimization calculations for the whole plant life have so far always indicated that continuous refuelling or discontinuous refuelling of partial cores leads to lower total fuel costs than regular complete core exchanges would. It is obvious that a certain number of exchanges of technically unequal partial cores will be inevitable in order to obtain the so-called equilibrium stage, in which the exchanged partial cores are identical and the exchange frequency, or rather the refuelling rhythm, depends only on the load factor.

5.2.3 The equilibrium period ($t_e - t_i$). During this period, as was stated above, the exchanged partial cores are identical. As a result, the fuel expenditures and credits relating to these so-called "batches" may be assumed to be virtually constant. During this period there will be good proportionality between the fuel cost and electrical energy generation.

5.2.4 The "running-out" period ($t_f - t_e$). The period at the end of the nuclear plant's life, when the last reactor core is to be consumed and the reactor is prepared for its final shut-down. During this period expenditures for completing the last fuel cycle and the credits involved are to be taken into account.

From the different aspects that have been schematically represented as a function of time in Fig. 1 (*A-G*) it is possible to trace the evolution in time of a number of distinct simultaneous phenomena, which are closely related to the sequence of the successive fuel cycles of a nuclear power plant over its whole life.

Plot A gives the subdivision of plant life into the four periods just defined.

Plot B gives some idea of the weight of fissile material in the cycle (in fabrication, in core, on site, reserve, in cooling, in reprocessing).

At the same time it provides a rough guide to the capital expenditure on nuclear fuel during plant life, though the precise amounts may tend to rise or fall in time, owing to variations in factors making up the cost of the nuclear fuel. This plot also gives an idea of the technologically and economically pulsed nature of nuclear plant operation with regard to fuelling. The frequency and amplitude of these pulses during the running-in period are both variable and are both determined by intimately related technological and economical factors. During the equilibrium period, however, the amplitude is by definition constant, together with the frequency, since the load factor is supposed to be constant over this period.

Plot C provides a purely administrative and accounting view. The arrows pointing upwards (V_j) represent fertile and fissile material credits on the dates they are planned or assumed to be granted (t_j), while those pointing downwards represent nuclear fuel cycle expenditures (S_j) on the dates on which they are planned or assumed to be effected (t_j).

The purpose of this arbitrary model is to illustrate:

a) that the algebraical sum of incurred expenditures and credits cannot be expected to be proportional to power generation during construction, running-in and running-out periods, but is certainly proportional to the electrical energy produced during the equilibrium period as a logical consequence of its definition;

b) the period during which expenditures are effected and credits are cashed, i.e., the plant's financial fuel cycle life, considerably exceeds the effective electricity production period;

c) though correlated, to a marked extent, refuelling and related outlays and credits do not coincide in time;

d) the rhythm at which similar expenditures and credits individually occur will be geared to the refuelling rhythm.

Plot E gives a schematic arbitrary model of the electricity production of the plant.

Plot F is the time-axis, the years are indicated by little dot-dash vertical lines, significant dates by vertical arrows. The following important dates are to be noted: t_0 – if a plant that became critical at the time t_s starts "commercial electricity production" at the time t_i, during the fifth year, the reference date for application of the present worth method will be the 1st of January of this fifth year and is denoted t_0, as already mentioned in Chapter 2.

Plot G gives an indication of the value which the present worth factor $(1+i)^{-n}$ adopts as a function of t. The conversion of the fuel cycle cost factors to their present worth value will be done at time intervals of one month. This means that two financial operations carried out within a period of less than one month can be regarded as simultaneous and the same present worth factor will be applied to them. Henceforth, any present worth value will be indicated by an asterisk.

Other important dates are:

t_c = Decision to build the power station; beginning of the construction period;

t_s = Date of first criticality of the nuclear reactor; commencement of electrical energy production and possibly plant-acceptance test runs; beginning of the running-in period;

t_i = Time at which the reactor starts to operate according to its planned nuclear equilibrium; t_i does not necessarily coincide with a refuelling, though for the sake of simplicity this assumption can be made;

t_e = Time after which the reactor will no longer be operated according to equilibrium characteristics: beginning of the running-out period;

t_z = Final shut-down of nuclear power plant, electricity production definitely stopped;

t_f = End of dismantling; date of the receipts of the last credits does not necessarily relate to the fuel cycle.

As can be concluded from the above considerations and discussion of the plots drawn in Fig. 1, only some of the expenditures depend on the energy produced, while another, constant percentage is determined by plant characteristics. If "net fuel cycle costs" are now defined as being the positive difference between fuel expenditures and fuel credits, these "net fuel cycle costs" can be split into two main parts.

$$C_f^* = C_{f_1}^* + C_{f_2}^*$$

Where $C_{f_1}^*$ = fixed costs (u.a.)

$C_{f_2}^*$ = variable ("proportional") costs (u.a.)

$C_{f_2}^*$ are costs that directly depend on the amount of energy produced.

In order to obtain more precise knowledge as to which of these two cost categories the different cost factors should be allotted, a number of definitions will be given and the different cost elements summarized and grouped.

5.3 — Basic concepts and definitions

Economic operations concerning the fuel cycle of a nuclear power plant start with the purchase of the uranium as UF_6 or U_3O_8 for the first reactor charge and end with the payment of the credits for the last charge. The time elapsing between these two dates is considered as the total "fuel cycle period".

A single "batch" is defined as a quantity of fuel elements all purchased together and later reprocessed at a certain time.

The algebraical sum of all expenditures and credits concerning a single batch, present-worthed as at the date of uranium purchase, is defined as the "net refuelling expenditure". During the equilibrium period, this value will constantly repeat itself and will then be defined as "average net refuelling expenditure" S_r.

In order to be able to apply the appropriate present worth coefficient to the different batches, the batch purchase schedule must be known and at the same time the payment schedules for each individual batch have to be defined. For each quantity of fuel the following operations and constituting cost elements must be considered:

	Cost element	Unit
I. Purchase of uranium	First charge weight	kg
	Individual batch weights	kg
	Spare elements weight	kg
	Uranium cost at initial enrichments	u.a.*/kg
II. Conversion	First charge weight	kg
	Individual batch weights	kg
	Spare elements weight	kg

* Calculations are made in units of account (u.a.) of the European Monetary Agreement (1 u.a. = 50 FB = 4.00 DM = 4.937 FF = 625 Lit. = 3.62 HFL).

III. Pelletizing	First charge weight	kg
	Individual batch weights	kg
	Spare elements weight	kg
	Pellet sintering cost	u.a./kg
IV. Fabrication of fuel elements	First charge weight	kg
	Individual batch weights	kg
	Spare elements weight	kg
	Fabrication cost	u.a./kg
V. Reprocessing	Individual batch weights	kg
	U and Pu losses during reprocessing (wt. % of reprocessed U, Pu)	%
	Reprocessing costs	u.a./kg
VI. Conversion of recovered U and Pu	Individual batch weights	kg
	U and Pu losses during conversion (wt. % of converted U, Pu)	%
	Reconversion cost in UF_6	u.a./kg
	Pu content in initial, final and equilibrium batches	g/kg U_{int}*
	Pu conversion cost	u.a./g Pu
	U-235 content in initial, final and equilibrium batches (wt. %)	%
VII. Restitution	Cost of U in UF_6 form (final enrichment)	u.a./kg U
	Pu sales price	u.a./g Pu
	Fresh fuel transportation cost	u.a./kg U
VIII. Various operations	Irradiated fuel transportation cost	u.a./kg U
	Loan of irradiated fuel cask	u.a./day
	Transport insurance	u.a./kg U
	Third party liability	u.a./year
	Storage cost before reprocessing	u.a./day

As was concluded from the analysis of Fig. 1, only some of the expenditures are contingent on the energy produced while another part, which remains constant, is only a function of the plant characteristics. Now the average net refuelling expenditures S_r (during the equilibrium period), defined as the algebraical sum of all expenditures and credits concerning a single batch, calculated as at the date of uranium purchase by the present worth method, are completely dependent on the energy production. On the other hand, as far as the initial outlay and the running-in expenses are concerned, only some of them depend on the energy production, while some can be regarded as constant.

* kg U_{int} : kg of uranium (enriched or natural) introduced into the reactor.

In the ideal case, if the fuel cycle were always at equilibrium, there would be no fixed expenses of the type being considered here, all expenditures being proportional to energy production.

Since, as has been said before, the expenses incurred during the equilibrium period are strictly proportional to the energy production, such an ideal cycle, coinciding with the proportional part of the fuel cycle expenditures, can be obtained by artificially extending the equilibrium period to the whole fuel cycle period, starting from the first energy production. The value of this ideal cycle, to be known as the "extrapolated equilibrium cycle" will be calculated by multiplying the average net refuelling expenditure (S_r) by the sum of the present worth coefficients for the dates in respect of which the S_r values are effective during the equilibrium period and the dates which are obtained by extending the regular recurrence of these expenditures S_r to the running-in and running-out period. Consequently fuel cycle expenditures can be precisely split into the two categories:

a) **Proportional cost:** depending on the produced energy. It coincides with the expenditures for the extrapolated equilibrium fuel cycle.

b) **Fixed cost:** all fuel cycle costs, apart from the proportional cost which are dependent on the particular operating characteristics of a nuclear plant.

This latter value is obtained by deducting the total present worth value of the proportional cost from the total present worth value of the fuel cycle cost.

Actually all expenses relating to:

— the excess of the first fuel charge expenditures
— the final credits for the last charge
— the excess of running-in and running-out period refuelling expenditures
— the spare parts fuel element expenditures,

are part of the *fixed cost.*

A logical consequence of this is to express the fuel cycle cost by the two-term formula.

5.4 — Calculation procedure

Table I (p. 44) gives a survey of the different financial transactions involved in the fuel cycle, the material weights, specific cost and total cost concerning each operation for the first core, each of the individual batches and the spare parts fuel elements.

This table gives the components of table II, determining the present worth value of the total cost of each batch during the equilibrium period, referred to the date of uranium purchase.

In table II (p. 45) the present worth method can then be applied to the related expenditures and credits on the respective dates, which should be known.

Table III (p. 46) gives the present worth value for the cost of the fuel cycle during the equilibrium period. There are four columns. The first gives the equilibrium batch numbers, the second the related dates, the third the related present worth coefficients and the fourth the net fuel batch expenditures. The sum of these present worth coefficients multiplied by the unit net fuel batch expenditure gives the total present worth value for the fuel cycle cost during the equilibrium period. Table IV (p. 46) lists the fuel cycle expenditures during the running-in period with the relevant dates, present worth factors and resulting present worth values, which are summarized to give the present worth value for the total fuel cycle expenditures during the running-in period. The same procedure is followed in table V (p. 47) for the running-out period, giving the present worth value for the total fuel cycle expenditures during the running-out period. Table VI (p. 47) lists the fuel cycle credits during the running-in and running-out period and the resulting total present worth value for these credits. From tables III, IV, V and VI the present worth value for the fuel cycle expenditures during the complete fuel cycle period can now be determined. The sum of the results of these tables, less the total present worth value of the credits during the running-in and running-out periods, equals the present worth value for the total net expenditures for the fuel cycle (see table VII, p. 48).

If the present worth value for the total net expenditures for the extrapolated fuel cycle is deducted from the figure obtained from table VII, the present worth value of the fixed costs of the fuel cycle (table VIII, p. 48) is obtained.

The present worth value for the total net expenditures for the extrapolated fuel cycle is calculated by the following formula:

$$S_r \times \frac{i_m}{1-\frac{1}{(1+i_m)^p}} \times \frac{1-\frac{1}{(1+i_m)^{n_{tot.}}}}{i_m}$$

where i_m = monthly interest rate: $(1+i_m)^{12} = 1+i$ and i the yearly interest rate.

p = period of the fuel during equilibrium, i.e., number of months between two refuellings.

$n_{tot.}$ = total number of months covered by the extrapolated equilibrium period, i.e., $(t_z - t_s)$ where t_z is the date of final shutdown of the reactor and t_s the date of the first criticality.

In the above formula the first factor spreads S_r equally over the p months of the fuel cycle period during equilibrium; the second factor being the cumulated present worth coefficient actualizes at once the this way obtained monthly rates involved during the entire energy-production life of the plant.

Finally, table IX (p. 49) gives the present worth quantity for the total energy produced as a function of possible load factors. By simple appropriate division by the adopted average yearly utilisation time in hours, the specific (per kWh produced) fixed, proportional and total cost can now be determined as for the fuel cycle.

Summary of the input data for the calculations

Technical:

First charge weight	kg (at % enrichement)
Individual batch weight	kg (at % enrichment)
Spare fuel elements weight	kg (at % enrichment)
Uranium losses (during irradiation)	%
Uranium losses (in chemical reprocessing)	%
Plutonium losses (in chemical reprocessing)	%
Uranium losses (in reconversion)	%
Plutonium losses (in reconversion)	%
Spec. plutonium production	g/kg $U_{intr.}$*

Specific expenditures:

Uranium as UF_6 (% enrichment)	u.a./kg U
Conversion Pellet sintering Fuel elements fabrication	u.a./kg U
Fresh fuel transportation	u.a./kg U
Irradiated fuel transportation	u.a./kg U
Lease of irradiated fuel cask	u.a./kg
Transportation insurance	u.a./kg U
Third party liability	u.a./year
Storage expenditure before reprocessing	u.a./
Reprocessing	u.a./kg U
Reconversion in UF_6	u.a./kg U
Pu conversion	u.a./g Pu

Specific credits:

Uranium as UF_6 (% enrichment) 1st batch	u.a./kg U
Uranium as UF_6 (% enrichment) 2nd batch	u.a./kg U
Uranium as UF_6 (% enrichment) 3rd batch	u.a./kg U
Uranium as UF_6 (% enrichment) equilibrium batch	u.a./kg U
Plutonium	u.a./g Pu*

* The plutonium production per kg of uranium introduced into the reactor may be the fissile plutonium production or the total plutonium production. The specific Pu credit must be established accordingly.

TABLE I

	Weight	Specific cost of operation	Total cost of operation
Purchase of UF_6			
first charge	kg	u.a./kg	u.a.
individual batches	kg	u.a./kg	u.a.
spare fuel elements	kg	u.a./kg	u.a.
Fabrication			
first charge	kg	u.a./kg	u.a.
individual batches	kg	u.a./kg	u.a.
spare fuel elements	kg	u.a./kg	u.a.
Transportation and insurance for individual batches	kg	u.a./kg	u.a.
Chemical reprocessing: individual batches*	kg	u.a./kg	u.a.
Reconversion: individual batches*	kg	u.a./kg	u.a.
Conversion of Pu: individual batches*	g	u.a./g	u.a.
*Credits for each batch**			
Credits for uranium	kg	u.a./kg	u.a.
1st batch	kg	u.a./kg	u.a.
2nd batch	kg	u.a./kg	u.a.
... batch	kg	u.a./kg	u.a.
eq. batch	kg	u.a./kg	u.a.
Credit for Pu: individual batch	g	u.a./g	u.a.

* Uranium (and Pu) losses have been subtracted.

* See footnote p. 43

TABLE II

*PRESENT WORTH VALUE FOR THE TOTAL COST OF EACH BATCH, DURING THE EQUILIBRIUM PERIOD, REFERRED TO THE PURCHASING DATE OF THE URANIUM**

Load factor:

Date (months)	Cost item	Value in u.a.	Present worth coefficient	Present worth value of expenditure or credits u.a.
	1. Fabrication instalment rate			
	2. Fabrication instalment rate			
	3. Fabrication instalment rate			
	4. Fabrication instalment rate			
	Purchase of U			
	Transportation and insurance			
	Reprocessing and conversion			
	Pu credit (−)			
	U credit (−)			
Present worth value of the cost of the batch			$S_r =$	u.a.

* Calculation in relation to present worth values should be effected on a monthly basis. A quarterly approach is also permissible.

TABLE III

PRESENT WORTH VALUE FOR THE COST OF THE FUEL CYCLE DURING THE EQUILIBRIUM PERIOD

Load factor			
Batch number	Date* (No. of months)	Present worth coefficient	Value in u.a.
j	n	$(1+i)^{-n}$	S_{jr}**
		$\Sigma(1+i)^{-n}$	
Total present worth value of the fuel cycle cost during the equilibrium period $\Sigma(1+i)^{-n} \times S_{jr}$ in u.a.			

* Reference date is t_0.

** Normally S_{jr} should repeat itself as a constant equal to S_r.

TABLE IV

FUEL CYCLE EXPENDITURES DURING RUNNING-IN PERIOD

Load factor:

Date (in months) from t_0)	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of expenditures in u.a.
n		S_j	$(1+i)^{-n}$	S_j*
Total present worth value of expenditures during running-in period in u.a.				ΣS_j* =

TABLE V

FUEL CYCLE EXPENDITURES DURING THE RUNNING-OUT PERIOD

Load factor:

Date (in months from t_0)	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of expenditures in u.a.
n		S_j	$(1+i)^{-n}$	S^*_j
Total present worth value of expenditures during the running-out period in u.a.				$\Sigma S^*_j =$

TABLE VI

FUEL CYCLE CREDITS DURING THE RUNNING-IN AND RUNNING-OUT PERIODS FOR URANIUM AND PLUTONIUM

Load factor:

Date (in months from t_0)	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of credits
n		V_j	$(1+i)^{-n}$	V^*_j
Total present worth value of credits during running-in and running-out periods in u.a.				$\Sigma V^*_j =$

TABLE VII

Cost specification		Cost in u.a.
Total present worth value of the fuel cycle cost during the equilibrium period (Table III)		
Total present worth value of the expenditures during the running-in period (Table IV)		
Total present worth value of the expenditures during the running-out period (Table V)	+	
Total present worth value of credits during the running-in and running-out periods (Table VI)	−	
Total present worth value of the net expenditures for the fuel cycle C^*_f		

TABLE VIII

Total present worth value of the net expenditures for the fuel cycle (Table VII) C^*_f		
Total present worth value for the cost of the extrapolated fuel cycle $C^*_{f_2}$	−	
Total present worth value for the fixed costs of the fuel cycle $C^*_{f_1}$		

TABLE IX

PRESENT WORTH VALUE OF THE TOTAL ENERGY PRODUCED FOR DIFFERENT POSSIBLE LOAD FACTORS

Year	Present worth coefficient	Produced energy in kWh			Load factor
		Load factor 0.6	Load factor 0.7	Load factor 0.8	
	$(1+i)^{-N}$	E_{N_1}	E_{N_2}	E_{N_3}	E_{N_4}
1					
2					
3					
4					
N					
	$\sum_N (1+i)^{-N}$	E_{N_1}	E_{N_2}	E_{N_3}	E_{N_4}
Present worth amount of energy produced		$\Sigma E^*{}_{N_1} = \sum_N (1+i)^{-N} \times E_{N_1}$	$\Sigma E^*{}_{N_3} = \sum_N (1+i)^{-N} \times E_{N_2}$	$\Sigma E^*{}_{N_2} = \sum_N (1+i)^{-N} \times E_{N_3}$	$\Sigma E^*{}_{N_4} = \sum_N (1+i)^{-N} \times E_{N_4}$

* The asterisks indicate present worth values.

6 — OPERATING, MAINTENANCE AND INSURANCE COSTS

The operating, maintenance and insurance costs are all the expenses which are to be recorded for accounting purposes during the operation period; the fuel costs are not included.

This head embraces the following items:

Account Number

31 — Personnel costs (including overheads)

This item includes all expenses for the staff necessary on the site for regular and steady-state operation and maintenance of the plant in order to keep the availability factor of the plant at as high a level as possible. These expenses include not only direct salaries, but all related indirect charges such as social security payments, overtime rates, health insurance, etc. They are independent of the quantity of energy produced.

This item can be divided into various sub-items corresponding to the various personnel categories, such as:

— operating staff in charge of energy production and responsible for nuclear fuel handling;

— technical staff responsible for all fuel management matters, i.e., out-of-pile fuel operations such as controls, storage and irradiation;

— maintenance staff in charge of all equipment whose function is to repair any minor damage occurring during reactor operation and to carry out all scheduled maintenance operation;

— staff of the auxiliary departments (i.e., administration and health physics sections). This does not include the staff engaged on special tasks not immediately relating to normal operation, such as scientific staff working in the plant prior to start-up.

Details of staff requirements for nuclear power stations and an example of the typical staff organization of a graphite-gas nuclear power station are given in the Report of the Groupement (Appendix 12, p. 3 and following).

32 — Insurance costs

This item includes costs relating to the insurance of the plant and the third party liability.

32.1 — Plant insurance

This item comprises all expenses relating to insurance against material damage caused to the installations. The yearly premiums depend on numerous factors, such as the type, purpose and capacity of the reactors, and is independent of the number of kWh produced.

The insurance premiums during the construction period are recorded separately in the accounts and added to the total investment cost (See Chapter 4, Plant Costs).

32.2 — Third party liability

This item includes all payments relating to the insurance premiums that the operator of nuclear plant has to pay in order to cover himself against third party liability resulting from nuclear risks.

The cost of nuclear liability insurance depends on the location, safety characteristics and thermal capacity of the nuclear plant, rather than the capital cost.

33 — Taxes

This item covers all taxes which may be paid in connection with the operation of a nuclear power plant (annual taxes due to government and local Authorities).

34 — Consumable material

The consumable material to be taken into account under this heading is that which is normally supplied for the steady-state running of the plant, with the exception of all equipment or products necessary for special operations (accidentals overhauls or exceptional repair).

This item covers, for instance: coolant make-up, D_2O make-up, burnable poisons in water reactors, gas and liquid filters, oil and greases, clothing and shoes for contaminated zones, cleaning materials, etc.

35 — Spare parts

This item only includes expenses for spares which are necessary for the normal routine maintenance programme drawn up for the whole life of the plant.

The major spare parts, which are generally ordered together with the first equipment of the plant, are deducted from this item and are included in the chapter relating to the investment costs.

Although it is not always possible to make a clear-cut distinction between items which are independent of the quantities of energy produced and those which are proportional to these energy quantities, it will be assumed that the situation is the following:

— Fixed: 31 Personnel costs
32 Insurance costs
33 Taxes

— Variable: 34 Consumable material
35 Spare parts

7 — TOTAL POWER GENERATING COST

Following the procedure adopted in the previous chapters, the total power generating cost will be calculated on the basis of one of the two methods indicated, i.e., an *a priori* or *a posteriori* evaluation, depending upon the circumstances under which this power generating cost is established.

The total power generating cost is expressed as a specific cost in mills per kWh delivered to the grid, i.e., is computed on the basis of the net electrical plant capacity and the plant operation factor (load factor). This characteristic figure is calculated by relating the amounts of the different cost components to the total amount of energy produced in the period considered (*both* amounts converted to present value if this method is applied). The total of these unit cost components gives the unit power cost.

The calculation schemes used below indicate the procedure to be adopted when computing the unit power generating cost of a nuclear power plant:

7.1 — The a priori unit power generating cost

7.1.1 — The capital cost

As described in Chapter 4, the capital cost is directly based on plant cost,this latter being for the *a priori* method, represented by the total amount of all direct and indirect cost items enumerated in Chapter 4, Plant Costs, 4.1 (Nos. 10-27). The capital cost is in the first instance calculated on an annual basis.

If i is the annual average interest rate for the capital invested and N the economic plant life (in years), and the capital depreciation is computed in such a way that the resulting annual fixed charges $[a]$ as a percentage of the initial capital are constant, the following equation is obtained:

$$[a] = \frac{i}{1 - \left(\frac{1}{1+i}\right)^N}$$

In some countries of the European Community taxes and return on capital are paid annually. In this case the annual fixed charges in %, if x is the average tax rate, are:

$$[a] = \frac{i}{1-\left(\frac{1}{1+i}\right)^N} + x$$

In the Community the value of $[a]$ is normally situated between 8 and 14% of the capital invested.

If the total plant cost is P, the annual capital charges A are:

$$A = P \times [a]$$

If part of the capital is not amortized (for instance land, heavy water, e.a.) P must be split into P_1 (not amortized capital items) and P_2 (capital items to be amortized).

$$A = P_1 \times i + P_2 \times [a]$$

The production of electricity to which the annual capital charges have to be related in order to find the unit capital cost is the electricity generated in the period for which the capital charges have been computed, e.g., a year. Multiplication of the annual utilization time (see Chapter 3, § 3.4) by the net electrical plant capacity gives the annual electric power generation E.

The unit capital cost p is obtained by dividing the annual capital charges by the annual output.

$$p = \frac{A}{E} \text{ mills/kWh}$$

7.1.2 — Fuel cycle cost

The calculation method and principles in the case of the fuel cycle costs were described in detail in Chapter 5. In fuel cycle costing, whether "a priori" or "a posteriori", application of the present worth method has proved to be the most appropriate way of taking the time factor into account.

A useful division of the total fuel cycle cost and the specific fuel cycle cost into a "fixed cost" part and a "variable cost" part has been effected.

As a result the present worth value of the total fuel cycle cost C_f can be represented as:

$C_f^* = C_{f_1}^* + C_{f_2}^*$ *(see Table VIII, Chapter 5. Fuel Cycle Costs)..

$C_{f_1}^*$ = present worth value of the "fixed cost" part of the complete fuel cycle period. This is any cost that does not directly depend on the amount of energy produced.

* The asterisks indicate present worth values.

$C^*_{f_2}$ = present worth value of the "variable cost" part of the complete fuel cycle period. This is the cost that is proportional to the energy produced.

As for the specific cost, the same procedure can be followed:

$$c^*_f = c^*_{f_1} + c^*_{f_2}$$

$c^*_{f_1}$ and $c^*_{f_2}$ can be written as:

$$c^*_{f_1} = \frac{C^*_{f_1}}{\sum E^*_N} \qquad \left\{ \begin{array}{l} \Sigma E^* = \text{present worth amount of electrical energy produced} \\ \text{(in kWh) — see Table IX, Chapter 5. Fuel Cycle} \\ \text{Costs, p. 49.} \end{array} \right.$$

$$c^*_{f_2} = \frac{C^*_{f_2}}{\Sigma E^*_N}$$

Because $C^*_{f_2}$ and E^*_N are proportional and uniformly distributed over the whole extrapolated fuel cycle period, the present worth factor has no influence on $c^*_{f_2}$.

The final formula for the specific fuel cycle cost is now:

$$c^*_f = c^*_{f_1} + c^*_{f_2} = \frac{C^*_{f_1}}{\sum E^*_N} + c^*_{f_2},$$

where $c^*_{f_1}$ varies according to ΣE^*, i.e., with the assumed load factor, while $c^*_{f_2}$ is constant.

7.1.3 — Operating, maintenance and insurance costs

Details of these costs, which form the third component of power generating costs, are given in Chapter 6 of the present document.

The unit operating, maintenance and insurance cost is obtained by dividing the following items calculated for one year, by the energy generated annually, defined earlier as E.

Accounting number	Denomination of costs
31	Personnel
32	Insurance
33	Taxes
34	Consumable material
35	Spare parts

* The asterisks indicate present worth values.

7.1.4 — The total unit power generating cost

The addition of the sub-totals for items 1, 2 and 3 gives the total unit power generating cost:

1 — unit capital cost
2 — unit fuel cycle cost
3 — unit operating, maintenance and insurance cost
4 — total unit power generating cost.

7.2 — The a posteriori unit power generating cost

7.2.1 — The capital cost

In the *a posteriori* situation, all costs relating to the plant cost are supposed to be known not only in respect of the amount but also with regard to the date at which they were incurred.

As shown in 4.2, the application of the present worth method is recommended in this case. All the direct and indirect costs, listed in 4. Plant Costs from No. 10 to 27, must be individually converted to present worth at t_0 and added up, except items 22. Contingencies, 24. Interest during construction, 25. Price revision and 26. Taxes during construction related to capital immobilization (see 4. Plant Costs). Expenses listed under No. 23 must also be converted to present worth at t_0; however, the amount figuring under item 23 will include the compensation for the revenue obtained from the energy produced and sold during the testing period of the plant, e.g., before t_0 (see 5. Fuel Cycle Costs).

Moreover, the expenses or revenue involved in the dismantling of the plant must be converted to present worth at t_0 and added algebraically to the amounts computed as indicated in this paragraph (Account No. 1.8).

The unit capital cost (p^*)* is calculated by dividing the total present worth capital cost (A^*)* so obtained by the amount of energy produced during the commercial life of the plant and converted to present worth at t_0, and is henceforth written as (E^*)* (see paragraph 7.1.2 of this chapter).

$$p^* = \frac{A^*}{E^*}$$

7.2.2 — The fuel cycle cost

As indicated in paragraph 7.1.2 of this chapter, fuel cycle costs are always calculated on the basis of the present worth method.

* The asterisks indicate present worth values.

With regard to the determination of the *a posteriori* fuel cycle cost evaluation method, the reader is referred to Euratom Report EUR 2521.e, mentioned earlier.

7.2.3 — Operating, maintenance and insurance cost

The unit operating, maintenance and insurance cost is calculated by dividing the total of items 31 through 35 (see 7.1.3) over the whole plant life, present worthed at t_0, by (E^*) over the whole plant life.

7.2.4 — The total unit power generating cost (a posteriori)

The arithmetical addition of sub-totals in items 1, 2 and 3 gives the total unit power generating cost.

1 — unit capital cost
2 — unit fuel cycle cost
3 — unit operating, maintenance and insurance cost
4 — total unit power generating cost.

8 — NUMERICAL EXAMPLE AND PRACTICAL APPLICATION OF THE CALCULATION SCHEMES ESTABLISHED IN THE PRECEDING CHAPTERS FOR COMPUTING TOTAL UNIT POWER GENERATING COST*

(*A priori method*)

The numerical example quoted below is simply intended to provide an illustration of the calculation method discussed in the previous chapters.

The numbers used should under no circumstances be regarded as representative. This is particularly the case as regards the rate of interest and the taxes, the lifetime and the items making up the specific plant costs, the cost of the fuel cycle, the operating and maintenance costs and insurance charges. The economic parameters employed in the calculations do not claim to be characteristic of a specific period of time or a particular country.

The technical parameters are not based on a detailed fuel management study aimed at the technical and economic optimization of operation of the reactor, but are rather average values estimated from reasonable suppositions.

The power station to be considered here is supposed to have the following characteristics:

— Reactor type	BWR = light water moderator and cooled
— Thermal power	1912 MW
— Electrical gross power	631 MW
— Electrical net power	600 MW
— Net efficiency	31.4%
— Average burn-up	
1st core	17,000 MWd/t
Subsequent cores	24,000 MWd/t
— Initial enrichment of uranium	
1st core	2.00%
Subsequent cores	2.35%

* Calculations are made in units of account (u.a.) of the European Monetary Agreement (1 EMA u.a. = 50 FB = 4.00 DM = 4.937 FF = 625 Lit. = 3.62 Fl.)

The economic parameters are fixed as follows:

- Design and construction period — 4 years
- Operation period = N — 20 years
- Dismantling period — 3 years
- Interest rate = i — 7% p.a.
- Tax rate = x — 3% p.a.
- Average load factor — 0.70 (running-in period = 4 years); 0.80 (equilibrium period = 16 years)
- Annual energy production = E = 3.6792×10^9 kWh (running-in period); 4.2000×10^9 kWh (equilibrium period)

8.1 — Plant costs

8.1.1 — Direct costs

Accounting number		Amounts in u.a.
10	Land purchase and ground tests	1 500 000
11	Site development and supplies during construction	1 000 000
12	Civil works	8 200 000
13	Reactor plant equipment	16 700 000
14	Turbine-generator plant	18 100 000
15	Electrical equipment	6 500 000
16	Auxiliary power plant equipment	5 000 000
17	Initial spare parts	3 000 000

8.1.2 — Indirect costs

Accounting number		Amounts in u.a.
20	Design, conception and inspection	7 000 000
21	Overheads during construction	4 000 000
22	Contingencies	2 000 000
23	Power plant operation cost during trials	1 500 000
24	Interest during construction	12 000 000
25	Price revision (escalation)	1 000 000
26	Taxes during construction	3 000 000
27	Customs duties	500 000

Total plant costs:

1. Direct costs	60 000 000 u.a.
2. Indirect costs	31 000 000 u.a.
Total:	91 000 000 u.a.

$$\text{Specific plant costs: } \frac{91\,000\,000 \text{ u.a.}}{600 \text{ MWe}} = 152 \text{ u.a./kWe.}$$

8.2 — Fuel cycle costs

Assumptions for the a priori fuel cycle cost evaluation

In order to establish this example of an *a priori* fuel cycle cost evaluation, a number of assumptions have had to be made, which will be discussed below.

1. A "four-zone" core exchange model has been adopted.
2. After exchanging the fourth fuel batch, the reactor is to enter its equilibrium stage.
3. During the running-in period the reactor is supposed to be operated at an average load factor of 0.7, which results in yearly refuelling of one batch.
4. For the rest of the reactor's power-generating life an average load factor of 0.8 has been estimated. The zone-wise refuelling will then take place every 15 months.
5. UF_6 payments are effected three months before this material is to be incorporated into the fuel element fabrication process.
6. Fabrication cost of first core, as of subsequent batches, is to be paid in three equal instalments: the first when fabrication is started, the second half-way through production (that is, three months later) and the third upon delivery (that is, another three months later).
7. The fuel element fabrication time is six months.
8. The entire first core is to be introduced into the reactor three months in advance of t_s (start-up).
9. Rather than predict the fuel management at the end of the plant life, it is supposed, for simplification purposes, that the operation of the reactor is stopped abruptly when the 17th fuel batch is discharged, i.e., that $t_e = t_z = 19\frac{3}{4}$ years. Batches 18, 19 and 20 are reprocessed and the residual value of U and Pu is credited on an average content basis. Significant dates in accordance with plot F of Fig. 1 have been set as follows:

$$
\begin{aligned}
t_c &= -\ 3\tfrac{1}{2} \text{ years}\\
t_s &= -\ \tfrac{1}{2} \text{ year}\\
t_0 &= 0\\
t_i &= +\ 3\tfrac{1}{2} \text{ years}\\
t_e &= t_z = 19\tfrac{3}{4} \text{ years.}
\end{aligned}
$$

10. The annual interest rate which serves as a base for the application of the present worth method, has been selected as 7% as above.
11. The time elapsing between UF_6 purchase and loading of the individual batch amounts in this chosen example to three three-month periods. All expenses and receipts concerning a batch are consequently present worthed to a time three such periods ahead of the introduction of this batch into the reactor.
12. Cooling (decay) time: 3 months
    Transport time: 1 month.

Summary of the Input Data for the Calculations

Technical:

First charge weight	116 400 kg (at 2% enrichment)
Individual batch weight	29 100 kg (at 2.35% enrichment)
Spare fuel elements weight	1 164 kg (at 2.35% enrichment)
Uranium losses (during irradiation)	3.1%
Uranium losses (in chemical reprocessing)	1%
Plutonium losses (in chemical reprocessing)	1%
Uranium losses (in reconversion)	0.3%
Plutonium losses (in conversion)	1%
Specific plutonium production	4.9 g/kg $U_{intr.}$
Specific plutonium production (first 4 batches)	3.7 g/kg $U_{intr.}$
Average specific plutonium production (batches 18, 19 and 20)	2.6 g/kg $U_{intr.}$

Specific expenditure:

Uranium as UF_6 (at 2% enrichment)	146.5 u.a./kg U
(at 2.35% enrichment)	183.5 u.a./kg U
Conversion Pellet sintering Fuel element fabrication Fresh fuel transportation	83 u.a./kg U
Irradiated fuel transportation Lease of irradiated fuel cask Transportation insurance Third party liability Storage expenditure before reprocessing	16 u.a./kg U
Chemical reprocessing	30 u.a./kg U
Reconversion into UF_6	6.5 u.a./kg U
Pu conversion	1.5 u.a./g Pu

Specific credits:

Uranium as UF_6	(0.88% enrichment) batch 1 (0.88% enrichment) batch 2 (0.88% enrichment) batch 3 (0.88% enrichment) batch 4	37.25 u.a./kg U
	(0.79% enrichment) batches 5-17	29.5 u.a./kg U
	(1.31% enrichment) average of batches 18, 19 and 20	75.7 u.a./kg U
Plutonium		10 u.a./g Pu

TABLE I

Operation	Weight	Specific cost of operation	Total cost of operation in u.a.
Purchase of UF_6			
First charge	116 400 kg	146.5 u.a./kg	17 052 600
Individual batches	29 100 kg	183.5 u.a./kg	5 339 850
Spare fuel elements	1 164 kg	183.5 u.a./kg	213 594
Fabrication			
First charge	116 400 kg	83 u.a./kg	9 661 200
Individual batches	29 100 kg	83 u.a./kg	2 415 300
Spare fuel elements	1 164 kg	83 u.a./kg	96 612
Transportation and insurance for individual batches	29 100 kg	16 u.a./kg	465 600
Chemical reprocessing* (individual batches)	28 198 kg	30 u.a./kg	845 940
Reconversion of U* (individual batches)	27 916 kg	6.5 u.a./kg	181 454
Conversion of Pu* (individual batches)			
Nos. 1-4	106 593.00 g	1.5 u.a./g	159 890
Nos. 5-17	141 164.10 g	1.5 u.a./g	211 746
Nos. 18, 19 and 20	224 771.00 g	1.5 u.a./g	337 065
*Credits for each batch**			
Credits for U			
Nos. 1-4	27 832 kg	37.25 u.a./kg	1 036 742
Nos. 5-17	27 832 kg	29.50 u.a./kg	821 044
Nos. 18, 19 and 20 together	83 496 kg	75.70 u.a./kg	6 320 647
Credits for Pu			
Nos. 1-4	105 527.07 g	10 u.a./g	1 055 271
Nos. 5-17	139 752.46 g	10 u.a./g	1 397 525
Nos. 18, 19 and 20 together	222 456.00 g	10 u.a./g	2 224 560

* Uranium (and Pu) losses have been subtracted.

TABLE II

*PRESENT WORTH VALUE OF THE TOTAL COST OF EACH BATCH, DURING THE EQUILIBRIUM PERIOD, REFERRED TO THE PURCHASING DATE OF THE URANIUM**

Load factor: 0.8

Date (months)	Cost item	Value in u.a.	Presen worth coefficient	Present worth value of expenditure or credits in u.a.
0	Purchase of U	5 339 850	1.0000	5 339 850
+ 3	First instalment for fabrication	805 100	0.9832	791 574
+ 6	Second instalment for fabrication	805 100	0.9667	778 290
+ 9	Third instalment for fabrication	805 100	0.9505	765 248
+72	Transportation and insurance	465 600	0.6664	310 276
+73	Reprocessing of U	845 940	0.6626	560 520
+73	Reconversion of U	181 454	0.6626	120 231
+73	Conversion of Pu	211 746	0.6626	140 303
+73	U credit (−)	821 044	0.6626	544,024
+73	Pu credit (−)	1 397 525	0.6626	926 000
Present worth value of the cost of the batch in u.a.				$S_r = 7\ 336\ 268$

* Calculation in relation to present worth values is effected on a monthly basis.

TABLE III

PRESENT WORTH VALUE OF THE COST OF THE FUEL CYCLE DURING THE EQUILIBRIUM PERIOD

Load factor: 0.8

Batch number	Date (No. of quarters)	Present worth coefficient	Value in u.a.
8	+11	0.8302	7 336 268
9	+16	0.7629	7 336 268
10	+21	0.7011	7 336 268
11	+26	0.6442	7 336 268
12	+31	0.5920	7 336 268
13	+36	0.5440	7 336 268
14	+41	0.4999	7 336 268
15	+46	0.4593	7 336 268
16	+51	0.4221	7 336 268
17	+56	0.3879	7 336 268
		5.8436	
Total present worth value of the fuel cycle cost during the equilibrium period in u.a.			42 870 216

TABLE IV

FUEL CYCLE EXPENDITURES DURING RUNNING-IN PERIOD

Load factor: 0.7

Date (in months from t_0)	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of expenditures in u.a.
−18	Payment of U for the first charge	17 052 600	1.1068	18 873 818
−18	Payment of U for spare elements	213 594	1.1068	236 406
−15	First instalment for fabrication of the first charge	3 220 400	1.0883	3 504 761
−12	Second instalment for fabrication of the first charge	3 220 400	1.0700	3 445 828
− 9	Third instalment for fabrication of the first charge	3 220 400	1.0521	3 388 183
− 9	Payment of fabrication of spare elements	96 612	1.0521	101 645
− 3	Payment of U for batch 5	5 339 850	1.0161	5 425 822
0	First instalment for fabrication of batch 5	805 100	1.0000	805 100
+ 3	Second instalment for fabrication of batch 5	805 100	0.9832	791 574
+ 6	Third instalment for fabrication of batch 5	805 100	0.9667	778 290
+ 9	Payment of U for batch 6	5 339 850	0.9505	5 075 527
+ 9	Transportation and insurance of batch 1	465 600	0.9505	442 553
+10	Reprocessing and conversion of U+Pu in batch 1	1 187 284	0.9452	1 122 220
+12	First instalment for fabrication of batch 6	805 100	0.9346	752 446
+15	Second instalment for fabrication of batch 6	805 100	0.9189	739 806
+18	Third instalment for fabrication of batch 6	805 100	0.9035	727 408
+21	Payment of U for batch 7	5 339 850	0.8884	4 743 923
+21	Transportation and insurance of batch 2	465 600	0.8884	413 639
+22	Reprocessing and conversion of U+Pu in batch 2	1 187 284	0.8833	1 048 728
+24	First instalment for fabrication of batch 7	805 100	0.8735	703 255

TABLE IV (CONTD.)

Date (in months from t_0)	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of expenditures in u.a.
+27	Second instalment for fabrication of batch 7	805 100	0.8588	691 420
+30	Third instalment for fabrication of batch 7	805 100	0.8444	679 826
+33	Transportation and insurance of batch 3	465 600	0.8302	386 541
+34	Reprocessing and conversion of U+Pu in batch 3	1 187 284	0.8256	980 222
+45	Transportation and insurance of batch 4	465 600	0.7759	361 259
+46	Reprocessing and conversion of U+Pu in batch 4	1 187 284	0.7715	915 990
+60	Transportation and insurance of batch 5	465 600	0.7130	331 973
+61	Reprocessing of U batch 5	845 940	0.7090	599 771
	Reconversion of U batch 5	181 454	0.7090	128 651
	Conversion of Pu batch 5	211 746	0.7090	150 128
+75	Transportation and insurance of batch 6	465 600	0.6552	305 061
+76	Reprocessing of U batch 6	845 940	0.6515	551 130
	Reconversion of U batch 6	181 454	0.6515	118 217
	Conversion of Pu batch 6	211 746	0.6515	137 953
+90	Transportation and insurance of batch 7	465 600	0.6021	280 338
+91	Reprocessing of U batch 7	845 940	0.5988	506 549
	Reconversion of U batch 7	181 454	0.5988	108 655
	Conversion of Pu batch 7	211 746	0.5988	126 794
Total present worth value of expenditures during running-in period in u.a.				60 481 410

TABLE V

FUEL CYCLE EXPENDITURES DURING THE RUNNING-OUT PERIOD

Load factor: 0.8

Date*	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of expenditures in u.a.
+61	Purchase of U for batch 20	5 339 850	0.3564	1 903 123
+62	First instalment for fabrication of batch 18	805 100	0.3504	282 107
+63	Second instalment for fabrication of batch 18	805 100	0.3445	277 357
+64	Third instalment for fabrication of batch 18	805 100	0.3388	272 768
+66	Purchase of U for batch 19	5 339 850	0.3275	1 748 800
+67	First instalment for fabrication of batch 19	805 100	0.3220	259 242
+68	Second instalment for fabrication of batch 19	805 100	0.3166	254 895
+69	Third instalment for fabrication of batch 19	805 100	0.3113	250 628
+71	Purchase of U for batch 20	5 339 850	0.3009	1 606 761
+72	First instalment for fabrication of batch 20	805 100	0.2959	238 229
+73	Second instalment for fabrication of batch 20	805 100	0.2909	234 204
+74	Third instalment for fabrication of batch 20	805 100	0.2861	230 339
+80	Transportation and insurance of batches 18, 19 and 20	1 396 800	0.2584	360 933
+80 1/3	Reprocessing and conversion of U+Pu in batches 18, 19 and 20	3 415 866	0.2570	877 878
Total present worth value of expenditures during the running-out period in u.a.				8 797 264

* In quarters from t_0.

TABLE VI

FUEL CYCLE CREDITS DURING THE RUNNING-IN AND RUNNING-OUT PERIODS FOR URANIUM AND PLUTONIUM

Load factor: 0.8

Date*	Cost specification	Value in u.a.	Present worth coefficient	Present worth value of credits in u.a.
+ 10	Credit for U batch 1	1 036 742	0.9452	979 929
+ 10	Credit for Pu batch 1	1 055 271	0.9452	997 442
+ 22	Credit for U batch 2	1 036 742	0.8833	915 754
+ 22	Credit for Pu batch 2	1 055 271	0.8833	932 121
+ 34	Credit for U batch 3	1 036 742	0.8256	855 934
+ 34	Credit for Pu batch 3	1 055 271	0.8256	871 232
+ 46	Credit for U batch 4	1 036 742	0.7715	799 846
+ 46	Credit for Pu batch 4	1 055 271	0.7715	814 142
+ 61	Credit for U batch 5	821 044	0.7090	582 120
+ 61	Credit for Pu batch 5	1 397 525	0.7090	990 845
+ 76	Credit for U batch 6	821 044	0.6515	534 910
+ 76	Credit for Pu batch 6	1 397 525	0.6515	910 488
+ 91	Credit for U batch 7	821 044	0.5988	491 641
+ 91	Credit for Pu batch 7	1 397 525	0.5988	836 838
+241	Credits for U batches 18, 19 and 20	6 320 647	0.2570	1 624 406
+241	Credits for Pu batches 18, 19 and 20	2 224 560	0.2570	571 712
Total present worth value of credits during running-in and running-out periods in u.a.				13 709 360

* In months from t_0.

TABLE VII

Cost specification		Cost in u.a.
Total present worth value of the fuel cycle cost during the equilibrium period (Table III)		42 870 216
Total present worth value of the expenditures during the running-in period (Table IV)		60 481 410
Total present worth value of the expenditures during the running-out period (Table V)		8 797 264
	+	112 148 890
Total present worth value of credits during the running-in and running-out periods (Table VI)		13 709 360
	−	
Total present worth value of the net expenditures for the fuel cycle C^{*}_{f}		98 439 530

TABLE VIII

Total present worth value of the net expenditures for the fuel cycle (Table VII) C^{*}_{f}		98 400 000
Total present worth value for the cost of the extrapolated fuel cycle $C^{*}_{f_2}$		66 700 000
	−	
Total present worth value for the fixed costs of the fuel cycle $C^{*}_{f_1}$		31 700 000

* Calculated according to the formula on page 42.

TABLE IX

PRESENT WORTH VALUE OF THE TOTAL ENERGY PRODUCED FOR DIFFERENT POSSIBLE LOAD FACTORS

Year	Present worth coefficient	Produced energy in kWh	
		Load factor 0.7	Load factor 0.8
1	0.9346	$3\,679.2 \times 10^6$	
2	0.8734	$3\,679.2 \times 10^6$	
3	0.8163	$3\,679.2 \times 10^6$	
4	0.7629	$3\,679.2 \times 10^6$	
5	0.7130		4.200×10^6
6	0.6663		4.200×10^6
7	0.6227		4.200×10^6
8	0.5820		4.200×10^6
9	0.5439		4.200×10^6
10	0.5083		4.200×10^6
11	0.4751		4.200×10^6
12	0.4440		4.200×10^6
13	0.4150		4.200×10^6
14	0.3878		4.200×10^6
15	0.3624		4.200×10^6
16	0.3387		4.200×10^6
17	0.3166		4.200×10^6
18	0.2959		4.200×10^6
19	0.2765		4.200×10^6
20 (0.75)	0.2584		3.150×10^6

Present worth amount of energy produced: $42{,}459 \times 10^6$ kWh

8.3 — Operating, maintenance and insurance costs

Accounting number		Amounts in u.a. (annually)
31	Personnel	500,000
32	Insurance	750,000
33	Taxes	100,000
34	Expendable material	900,000
35	Spare parts	900,000
	Total (annually)	3,150,000

8.4 — Total unit power generating cost

8.4.1 — The capital cost

As described in 7.1.1, the total amount of capital invested (P) is represented by the addition of the values of items 10-27 as shown in that chapter.

A. Direct costs	60,000,000 u.a.
B. Indirect costs	31,000,000 u.a.
Total of P =	91,000,000 u.a.

With $i = 7\%$, $x = 3\%$ and $N = 20$ years the annual capital charges (A) are

$$A = 91{,}000{,}000 \times \left[\frac{0.07}{1 - \left(\dfrac{1}{1+0.07}\right)^{20}}\right] + 0.03$$

$$= 91{,}000{,}000(0.094+0.03) = 11{,}284{,}000 \text{ u.a.}$$

The unit capital cost p is:

$$p = \frac{11{,}284{,}000 \times (\text{u.a.}) \times 10^3}{3.6792 \times 10^9 (\text{kWh/a})} = 3.06 \text{ mills/kWh (running-in period)}$$

$$p = \frac{11{,}284{,}000 \times (\text{u.a.}) \times 10^3}{4.2000 \times 10^9 (\text{kWh/a})} = 2.69 \text{ mills/kWh (equilibrium period)}$$

8.4.2 — Fuel cycle cost

Fixed unit fuel cycle cost $$c^*_{f_1} = \frac{31.700.000 \text{ u.a.} \times 10^3}{42.459 \times 10^6 \text{ kWh}} = 0.75 \text{ mill/kWh}$$

Variable unit fuel cycle cost $$c^*_{f_2} = \frac{66.700.000 \text{ u.a.} \times 10^3}{42.459 \times 10^6 \text{ kWh}} = 1.57 \text{ mill/kWh}$$

Total unit fuel cycle cost $$c^*_f = 2.32 \text{ mills/kWh}$$

8.4.3 — The unit operating, maintenance and insurance costs

$$\frac{3.150.000 \text{ (u.a.)} \times 10^3}{3.6792 \times 10^9 \text{ (kWh/a)}} = 0.86 \text{ mill/kWh (running-in period)}$$

$$\frac{3.150.000 \text{ (u.a.)} \times 10^3}{4.2000 \times 10^9 \text{ (kWh/a)}} = 0.75 \text{ mill/kWh (equilibrium period)}$$

8.4.4 — Total unit power generating cost (mills/kWh)

	Running-in period	Equilibrium period
1. Unit capital cost	3.06	2.69
2. Unit fuel cycle cost	2.32	2.32
3. Unit operating, maintenance and insurance cost	0.86	0.75
4. Total unit power generating cost.	6.24	5.76

PRESENT WORTH COEFFICIENTS

TABLE I

Yearly discount rate

Month	4%	5%	6%	7%	8%
−24	1.0815	1.1025	1.1235	1.1449	1.1664
−23	1.0781	1.0981	1.1181	1.1385	1.1590
−22	1.0746	1.0936	1.1127	1.1321	1.1516
−21	1.0711	1.0892	1.1073	1.1257	1.1442
−20	1.0676	1.0847	1.1019	1.1194	1.1369
−19	1.0641	1.0803	1.0966	1.1131	1.1296
−18	1.0606	1.0760	1.0913	1.1068	1.1224
−17	1.0572	1.0716	1.0860	1.1006	1.1152
−16	1.0537	1.0672	1.0807	1.0944	1.1081
−15	1.0502	1.0629	1.0755	1.0883	1.1010
−14	1.0468	1.0586	1.0704	1.0822	1.0940
−13	1.0434	1.0543	1.0652	1.0761	1.0870
−12	1.0400	1.0500	1.0600	1.0700	1.0800
−11	1.0366	1.0457	1.0549	1.0640	1.0731
−10	1.0333	1.0415	1.0498	1.0580	1.0663
− 9	1.0298	1.0373	1.0447	1.0521	1.0594
− 8	1.0265	1.0330	1.0397	1.0461	1.0527
− 7	1.0232	1.0289	1.0347	1.0403	1.0459
− 6	1.0198	1.0247	1.0296	1.0344	1.0392
− 5	1.0165	1.0205	1.0247	1.0286	1.0326
− 4	1.0131	1.0164	1.0197	1.0228	1.0260
− 3	1.0099	1.0122	1.0147	1.0161	1.0194
− 2	1.0066	1.0082	1.0098	1.0113	1.0129
− 1	1.0033	1.0041	1.0049	1.0057	1.0064
1	0.9967	0.9959	0.9951	0.9943	0.9936
2	0.9934	0.9919	0.9903	0.9888	0.9873
3	0.9902	0.9879	0.9855	0.9832	0.9809
4	0.9871	0.9839	0.9807	0.9777	0.9747
5	0.9838	0.9799	0.9759	0.9722	0.9684
6	0.9806	0.9759	0.9713	0.9667	0.9623
7	0.9773	0.9719	0.9665	0.9613	0.9561
8	0.9742	0.9681	0.9618	0.9559	0.9499

CONTINUATION OF TABLE I

Yearly discount rate

Month	4%	5%	6%	7%	8%
9	0.9710	0.9640	0.9573	0.9505	0.9439
10	0.9679	0.9602	0.9326	0.9452	0.9378
11	0.9647	0.9563	0.9480	0.9399	0.9319
12	0.9616	0.9524	0.9434	0.9346	0.9259
13	0.9584	0.9485	0.9388	0.9293	0.9200
14	0.9553	0.9446	0.9342	0.9240	0.9141
15	0.9522	0.9408	0.9298	0.9189	0.9083
16	0.9490	0.9370	0.9253	0.9137	0.9024
17	0.9459	0.9332	0.9208	0.9086	0.8967
18	0.9429	0.9294	0.9164	0.9035	0.8910
10	0.9398	0.9257	0.9119	0.8984	0.8853
20	0.9367	0.9219	0.9075	0.8933	0.8796
21	0.9336	0.9181	0.9031	0.8884	0.8740
22	0.9306	0.9144	0.8967	0.8833	0.8684
23	0.9276	0.9107	0.8944	0.8783	0.8628
24	0.9246	0.9070	0.8901	0.8735	0.8573
25	0.9215	0.9033	0.8857	0.8685	0.8518
26	0.9185	0.8997	0.8814	0.8636	0.8464
27	0.9156	0.8960	0.8772	0.8588	0.8410
28	0.9125	0.8923	0.8729	0.8540	0.8356
29	0.9096	0.8887	0.8687	0.8492	0.8302
30	0.9067	0.8851	0.8645	0.8444	0.8250
31	0.9038	0.8815	0.8603	0.8396	0.8197
32	0.9008	0.8780	0.8562	0.8349	0.8144
33	0.8978	0.8744	0.8520	0.8302	0.8093
34	0.8949	0.8709	0.8479	0.8256	0.8041
35	0.8920	0.8674	0.8438	0.8209	0.7989
36	0.8891	0.8638	0.8397	0.8163	0.7938
37	0.8862	0.8603	0.8356	0.8117	0.7888
38	0.8833	0.8568	0.8316	0.8072	0.7837
39	0.8804	0.8553	0.8276	0.8026	0.7787
40	0.8775	0.8499	0.8235	0.7981	0.7737
41	0.8747	0.8465	0.8195	0.7936	0.7688
42	0.8718	0.8430	0.8156	0.7892	0.7639
43	0.8690	0.8396	0.8116	0.7847	0.7590
44	0.8661	0.8362	0.8077	0.7803	0.7542
45	0.8633	0.8328	0.8038	0.7759	0.7493
46	0.8605	0.8294	0.7999	0.7715	0.7545
47	0.8577	0.8260	0.7961	0.7672	0.7398
48	0.8549	0.8226	0.7922	0.7629	0.7350
49	0.8522	0.8193	0.7883	0.7586	0.7303
50	0.8493	0.8160	0.7846	0.7544	0.7256

CONTINUATION OF TABLE I

Yearly discount rate

Month	4%	5%	6%	7%	8%
51	0.8466	0.8127	0.7807	0.7501	0.7210
52	0.8438	0.8094	0.7769	0.7459	0.7164
53	0.8410	0.8061	0.7732	0.7417	0.7118
54	0.8383	0.8028	0.7695	0.7376	0.7073
55	0.8356	0.7996	0.7658	0.7334	0.7027
56	0.8328	0.7963	0.7620	0.7293	0.6982
57	0.8302	0.7931	0.7583	0.7252	0.6938
58	0.8274	0.7898	0.7547	0.7211	0.6894
59	0.8247	0.7867	0.7510	0.7171	0.6850
60	0.8221	0.7835	0.7474	0.7130	0.6806

TABLE II

Yearly discount rate

Quarter	4%	5%	6%	7%	8%
−20	1.2165	1.2764	1.3380	1.4025	1.4693
−19	1.2046	1.2609	1.3187	1.3790	1.4413
−18	1.1929	1.2456	1.2996	1.3558	1.4139
−17	1.1812	1.2305	1.2808	1.3331	1.3869
−16	1.1697	1.2156	1.2623	1.3107	1.3605
−15	1.1583	1.2008	1.2441	1.2888	1.3346
−14	1.1470	1.1863	1.2261	1.2672	1.3091
−13	1.1358	1.1719	1.2084	1.2459	1.2842
−12	1.1248	1.1577	1.1099	1.2250	1.2597
−11	1.1138	1.1436	1.1737	1.2045	1.2357
−10	1.1029	1.1298	1.1567	1.1843	1.2122
− 9	1.0922	1.1161	1.1400	1.1644	1.1891
− 8	1.0815	1.1025	1.1235	1.1449	1.1664
− 7	1.0711	1.0892	1.1073	1.1257	1.1442
− 6	1.0606	1.0760	1.0913	1.1068	1.1224
− 5	1.0502	1.0629	1.0755	1.0883	1.1010
− 4	1.0400	1.0500	1.0600	1.0700	1.0800
− 3	1.0298	1.0373	1.0447	1.0521	1.0594
− 2	1.0198	1.0247	1.0296	1.0344	1.0392
− 1	1.0099	1.0122	1.0147	1.0171	1.0194
1	0.9902	0.9879	0.9855	0.9832	0.9809
2	0.9806	0.9759	0.9713	0.9967	0.9623
3	0.9710	0.9640	0.9573	0.9505	0.9439
4	0.9616	0.9524	0.9434	0.9346	0.9259
5	0.9522	0.9408	0.9298	0.9189	0.9083
6	0.9429	0.9294	0.9164	0.9035	0.8910
7	0.9336	0.9181	0.9031	0.8884	0.8740
8	0.9246	0.9070	0.8901	0.8735	0.8573
9	0.9156	0.8960	0.8772	0.8588	0.8410
10	0.9067	0.8851	0.8645	0.8444	0.8250
11	0.8979	0.8744	0.8520	0.8302	0.8093
12	0.8891	0.8638	0.8397	0.8163	0.7938
13	0.8804	0.8533	0.8276	0.8026	0.7787
14	0.8718	0.8430	0.8156	0.7892	0.7639
15	0.8633	0.8328	0.8038	0.7759	0.7493
16	0.8549	0.8226	0.7922	0.7629	0.7350
17	0.8466	0.8127	0.7807	0.7501	0.7210
18	0.8383	0.8028	0.7695	0.7376	0.7073
19	0.8302	0.7931	0.7583	0.7252	0.6938
20	0.8221	0.7835	0.7474	0.7130	0.6806
21	0.8140	0.7740	0.7366	0.7011	0.6676
22	0.8061	0.7646	0.7259	0.6893	0.6549

CONTINUATION OF TABLE II

Yearly discount rate

Quarter	4%	5%	6%	7%	8%
23	0.7983	0.7553	0.7154	0.6777	0.6424
24	0.7905	0.7461	0.7051	0.6664	0.6302
25	0.7828	0.7371	0.6949	0.6552	0.6182
26	0.7751	0.7282	0.6849	0.6442	0.6064
27	0.7676	0.7193	0.6750	0.6334	0.5948
28	0.7601	0.7106	0.6652	0.6228	0.5835
29	0.7527	0.7020	0.6556	0.6123	0.5724
30	0.7453	0.6935	0.6461	0.6021	0.5615
31	0.7381	0.6851	0.6368	0.5920	0.5508
32	0.7309	0.6768	0.6276	0.5820	0.5403
33	0.7238	0.6685	0.6185	0.5723	0.5300
34	0.7167	0.6604	0.6096	0.5627	0.5199
35	0.7097	0.6524	0.6008	0.5532	0.5100
36	0.7028	0.6445	0.5921	0.5440	0.5002
37	0.6959	0.6367	0.5835	0.5320	0.4907
38	0.6892	0.6290	0.5751	0.5259	0.4814
39	0.6824	0.6213	0.5668	0.5171	0.4722
40	0.6758	0.6138	0.5586	0.5084	0.4632
41	0.6692	0.6064	0.5505	0.4999	0.4544
42	0.6627	0.5990	0.5425	0.4915	0.4457
43	0.6562	0.5916	0.5347	0.4832	0.4372
44	0.6498	0.5846	0.5270	0.4751	0.4289
45	0.6435	0.5775	0.5194	0.4672	0.4207
46	0.6372	0.5705	0.5118	0.4593	0.4127
47	0.6310	0.5636	0.5044	0.4516	0.4048
48	0.6248	0.5567	0.4972	0.4440	0.3971
49	0.6187	0.5500	0.4900	0.4366	0.3895
50	0.6127	0.5433	0.4829	0.4293	0.3821
51	0.6067	0.5367	0.4759	0.4221	0.3748
52	0.6008	0.5302	0.4690	0.4150	0.3677
53	0.5950	0.5238	0.4622	0.4080	0.3607
54	0.5892	0.5174	0.4556	0.4012	0.3538
55	0.5834	0.5111	0.4490	0.3945	0.3471
56	0.5777	0.5049	0.4425	0.3879	0.3404
57	0.5721	0.4988	0.4361	0.3813	0.3340
58	0.5665	0.4928	0.4298	0.3750	0.3276
59	0.5610	0.4868	0.4236	0.3687	0.3214
60	0.5555	0.4809	0.4175	0.3625	0.3152
61	0.5501	0.4751	0.4114	0.3564	0.3092
62	0.5447	0.4693	0.4055	0.3504	0.3033
63	0.5394	0.4636	0.3996	0.3445	0.2975
64	0.5342	0.4580	0.3938	0.3388	0.2919

CONTINUATION OF TABLE II

Yearly discount rate

Quarter	4%	5%	6%	7%	8%
65	0.5290	0.4524	0.3881	0.3331	0.2863
66	0.5238	0.4469	0.3825	0.3275	0.2809
67	0.5187	0.4415	0.3770	0.3220	0.2755
68	0.5136	0.4362	0.3715	0.3166	0.2703
69	0.5086	0.4309	0.3662	0.3113	0.2651
70	0.5037	0.4256	0.3609	0.3061	0.2600
71	0.4987	0.4205	0.3557	0.3009	0.2551
72	0.4939	0.4154	0.3505	0.2959	0.2502
73	0.4891	0.4103	0.3455	0.2909	0.2455
74	0.4843	0.4054	0.3405	0.2861	0.2408
75	0.4796	0.4004	0.3355	0.2813	0.2362
76	0.4749	0.3956	0.3307	0.2765	0.2317
77	0.4703	0.3908	0.3259	0.2726	0.2273
78	0.4657	0.3861	0.3212	0.2673	0.2229
79	0.4611	0.3814	0.3166	0.2629	0.2187
80	0.4566	0.3767	0.3120	0.2584	0.2145
81	0.4522	0.3722	0.3075	0.2541	0.2104
82	0.4478	0.3677	0.3030	0.2498	0.2064
83	0.4434	0.3632	0.2986	0.2457	0.2025
84	0.4391	0.3588	0.2943	0.2415	0.1986
85	0.4348	0.3544	0.2901	0.2375	0.1949
86	0.4306	0.3501	0.2859	0.2335	0.1911
87	0.4264	0.3459	0.2817	0.2296	0.1875
88	0.4222	0.3417	0.2777	0.2257	0.1839
89	0.4181	0.3376	0.2737	0.2219	0.1804
90	0.4140	0.3335	0.2697	0.2182	0.1770
91	0.4100	0.3294	0.2658	0.2146	0.1736
92	0.4060	0.3254	0.2620	0.2110	0.1703
93	0.4020	0.3215	0.2582	0.2074	0.1671
94	0.3981	0.3176	0.2544	0.2039	0.1639
95	0.3942	0.3137	0.2508	0.2005	0.1607
96	0.3904	0.3099	0.2471	0.1972	0.1577
97	0.3866	0.3062	0.2436	0.1939	0.1547
98	0.3828	0.3024	0.2400	0.1906	0.1517
99	0.3791	0.2988	0.2366	0.1874	0.1488
100	0.3754	0.2952	0.2331	0.1843	0.1460

HYPOTHETICAL SITE CONDITIONS

General points of view for establishing hypothetical site conditions

Within definite limits, the capital cost of a nuclear power station is dependent on the site conditions. The location of the site, its accessibility and development with regard to transport, the geological and seismological conditions, the cooling water supply, the meteorological and hydrological conditions, the availability of local labour, the relationship to the transmission system and many other factors affect planning. These take effect partly in the extent of construction work for the development of the site, for the foundations of the structures, for dewatering during below-surface construction and others, thus in the costs of the civil engineering portion, with the foundations of the heavy structures in particular acting, under unfavourable conditions, as substantial cost-raising factors.

Likewise, unfavourable transport conditions entail the construction of long access roads and/or rail spurs, with the special requirements of heavy transport during the construction period and during operation exerting a special influence. With an advantageous location on the bank of waterway suitable for heavy transport, the transport problem may sometimes be solved better by the waterway, in which case, however, not unimportant structures are required for unloading. If existing routes of traffic or other commercially utilized structures and facilities are destroyed or unutilizable by the construction of the power station, there arise additional costs for their relocation and reconstruction which are directly chargeable to the power station.

On the other hand, the costs of the mechanical and electrical equipment, too, are influenced by local conditions. The type of circulating water supply, the annual pattern of circulating water temperatures and the available circulating water quantity decide whether fresh water cooling, which must always be striven for because of its economic advantages, will be possible or whether recooling operation must be chosen. With fresh water cooling the type of the circulating water (sea water or river water) and its impurities, the distance of the intake from the turbine house, the difference in altitude between water level and turbine condenser as well as the extreme level fluctuations at the intake point influence strongly the design of the intake structure with the mechanical water purification plant and the pumping equipment. Especially in case of a coastal location of the power station the civil engineering expenditure for the circulating water intake is considerable. The design of the turbine condenser, too, and ultimately the power station output attainable with a definite thermal output of the reactor are dependent on the c.w. supply by way of the average circulating water temperature.

Recooling operation by means of cooling towers results in additional expenditure for the cooling towers themselves and a loss of ouput due to the higher cooling water temperature and to the energy required for additional circulation.

Moreover, in this scheme the design of the make-up water facilities is dependent on the site conditions, particularly on the water quality. The highest degree of independence from sites with regard to cooling water have air condensing systems whose capital cost, as shown by experience, is even higher than that of the cooling tower installations.

The meteorological and hydrological conditions play a part in the case of nuclear power stations, above all in the determination of the criteria for nuclear safety. Together with the location of the site relative to residential developments, cities and major centers of population, above all the statistical distribution of wind direction, wind velocity and the incidence of temperature inversions govern the safety considerations. From these result finally the design criteria for a possible reactor containment shell and for the stack to discharge gaseous waste activities .The flood situation and ground water conditions determine criteria for the construction of the damp proofing of the reactor containment structure, of the liquid radioactive effluent treatment building and of storage buildings for irradiated fuel and solid radioactive wastes and concentrates. The basis for the safety considerations and establishment of design criteria are in each case the existing local safety regulations and the statutory regulations having priority. Although a common basis may be expected to exist generally within the countries of the Community, there prevails yet a dependence on the site with respect to the numerous local by-laws being valid in addition, and thus an influence on the capital cost.

The relationship to the transmission system exerts first an influence on the high voltage of the main generator transformer, from which fact will possibly depend, in the case of large capacities and high voltages, the changeover to considerably more expensive single-phase units. Moreover, the necessity of a second high-voltage system as far as possible independent of the main transmission system may imply for feeding ~~in~~ station start-up power a not inconsiderable additional outlay with the electrical station service equipment. The location of the high voltage outdoor switchyard of the power station, too, depends on the local situation. In many cases the power station has no such installation on its own site, but overhead lines lead directly from the high-voltage terminals of the transformers to the larger grid substation not far away. In other cases the local situation enforces the construction of an own outdoor switching compound on the power station site.

The costs for the civil engineering portion, which include a very high labour content, and for equipment erection are also sensitive with respect to the availability of skilled and unskilled local labour. If this force must be brought in daily from far away and/or housed in labour camps, this will cause an increase in cost for the site. Likewise, the proximity of building materials and aggregates, of workshops and material stores plays a not inconsiderable part.

Finally, the reactor type, too, has an influence on the site-dependent costs, in so far as the factors listed above have consequences differing from type to type. Thus, the safety criteria of different reactor types operate differently for a given site, the problem of transporting heavy items of plant may be of more or less importance, and the erection expenditure on the building site may govern the sensitivity of costs with respect to the availability of local labour.

If all these factors are allowed for, it becomes obvious that with the large number of influences and parameters the capital costs for two different sites are practically never fully comparable. To make a genuine comparison, the exact conditions must, therefore, be known of both sites. Only then will it be possible to eliminate the specific influences of the site and to arrive at a cost comparison of both plants reduced to a single site. To have available such a basis for comparing projects studied and for factually sound comparisons of different reactor systems, it is practical to start from a theoretical site with assumed conditions. One could be tempted to seek for this purpose an "average" site to be regarded as normal as possible in all countries of the Community. Due to the many parameters, however, this effort will encounter insurmountable difficulties. Such an "average" site must, therefore, be disregarded.

If it is assumed that each electricity supply undertaking will select in each case the most favourable site available from a number of possible ones, namely the most favourable for the reactor type concerned, the "hypothetical" site for each reactor type which is to be determined for comparison purposes must also satisfy this condition. But this fixes the guidelines for establishing the conditions of such a site. On the following pages, these conditions have been laid down.

A hypothetical site so defined will always safely lead to the lowest capital cost. When this is transferred to an actual site, additional costs must therefore be expected. If it is assumed, however, that today and in the near future only few nuclear power stations are under construction and will be constructed, in the majority of cases a more or less close approximation to the ideal site conditions should be obtained so that these additional capital costs, as related to the overall capital cost, will remain within moderate limits.

For the above-mentioned purpose is proposed a hypothetical site located immediately on the bank of a river with a favourable and sufficient cooling water supply. Fig. 1 shows a schematic layout plan of the power station. This plan shows only the conceptual arrangement of the buildings relative to each other as well as to the river and the access roads. In a specific case the layout plan will have to be adapted to the requirements of the reactor type chosen.

Geographical location

The site is a grass-covered level terrain on the east bank of a river running from south to north. It lies in the centre of a predominantly agricultural area of relatively low population density. A large city of approx. 200,000 inhabitants lies 50 km away. The site is favourably located with respect to rail and road connections. In spite of the location immediately on the river bank, the terrain is free from floods.

Land area size and land costs

The size of the fenced-in power station area suitable for the construction of two or three units each of 200 to 500 MW capacity is 8 ha. Including the area not fenced in, 15 ha of land in all have been purchased. The purchase price for the land totals 100,000 u.a. Besides this the land purchase entails no further commitments.

Access and transport development

A railway main line and a truck road pass the site parallel to the river at a distance of a few kilometers. The terrain between the site and the railway line or road is only slightly inclined and not cut by watercourses, so that construction of a railway spur and of an access road to the power station is possible under advantageous conditions. The truck road as well as the railway line are suitable for transporting heaviest items weighing up to 200 ton per piece and do not need any improvements (by the State).

	Access road	Railway spur
Length	5.0 km	8.0 km
Overall cost chargeable to the power station operator	400,000 u.a.	560,000 u.a.

It is assumed that all transport will be on land. In addition, however, there will be the possibility of transporting especially bulky and heavy parts to the site on water, as the river is navigable for heavy-load barges. In this case the cost arising for unloading facilities on the power station site will have to be added.

Construction of the connecting road and of the railway spur will be possible without any considerable relocation of existing roads, services and communication lines and other facilities, so that this will not entail any separate costs.

Altitude level of the construction site relative to the river

The power station site is situated 7.5 m above normal river water level and

1.5 m above maximum flood level. The river water level is subject to seasonal fluctuations averaging between -8 m and 4.5 m calculated from the power station site level.

Subsoil characteristics and load bearing capacity

The soil profile shows rather uniformly over the entire construction site alluvial deposits and rock fill below the topsoil stratum down to a depth of approx. 2.50 m, underlain by homogenous limestone strata of varying compositions and low settlement down to 15 m depth.

Allowable soil bearing of top stratum	3.0. kg/cm^2
Permissible load bearing of limestone strata	7.0. kg/cm^2 as a minimum

Over 15 m depth there is bedrock of higher load bearing.
No underground cavities exist in the limestone strata.

Seismic hazards

The site is located in a seismic zone presenting low hazards Earthquakes observed over the last 100 years reached intensities up to a maximum of 5 of the Mercalli-Sieberg scale.

Hydrological situation

Even at minimum flow the water flow of the river will be sufficient to cover the cooling water and raw make-up water requirements of the power station at its ultimate stage of construction without the biologically permissible heating limit being exceeded. The mean maximum temperature of the river water is 22 °C, the mean minimum temperature 4 °C. The water has a salinity of 6-8 mval/l of which approx. $\frac{1}{4}$ is carbonate hardness and a low content of organic matter in solution. The annual precipitation on site is on the average 700 mm. Natural drainage of the area is provided by the ground water flow directed towards the river following the land contours at a velocity averaging 100 m per year.

Drinking and process water may be drawn by wells from the ground water at approx. 12 to 15 m depth.

Meteorology and climatology

The annual wind distribution shows prevailing winds from the west through south quadrant with intensities averaging 4-5. There is no special daily variation in wind speed or direction. The wind velocity rises evenly with the altitude. The maximum wind velocity observed over the last few decades near the site and close to the surface was 90 km/h. The occurence of times with inversions is relatively rare, amounting on the average to approx. 10% of the entire year.

The annual average of air temperature is 15 °C, with maximum temperatures up to 38 °C on few hot summer days and lowest temperatures down to −15 °C in winter. Frost spells lasting for prolonged periods in winter may occur. Snow loads of 75 kg/m^2 of ground area as a maximum must be expected.

Population distribution and land use in surrounding region

The nearest large city of 200,000 inhabitants lies south of the building site on the river and is connected with it by the truck road and railway main line. Up to a radius of 40 km the surrounding region is rather sparsely populated. Special safety precautions on the reactors beyond the normal ones are not required.

In small towns situated within 30 km of the site there are only minor industrial manufacturing plants employing less than 100 people each. A chemical works producing photographic materials is not situated within this area.

Major industrial works are located in the above-mentioned large city. The remaining land surrounding the site is used largely as cultivated crop land or forest.

Liquid effluent treatment

All normal sewage and fecal sewage may be dumped to the river only after treatment in a sewage treatment plant. The surface drainage system drains directly to the river. Effluents from the chemical water treatment plant may be discharged only after neutralization.

All possibly active and radioactive liquid wastes must be decontaminated down to the tolerance dose value and will be either reused or discharged to the river after final monitoring. The following safety regulations will apply to all active effluents.

Regulations for radioactive waste discharge

The tolerance dose values established by the EURATOM Safety Regulations will apply to the discharge of liquid or gaseous active waste to the environment.

Storage of solid radioactive wastes and concentrates within the power station

It is assumed that only an intermediate storage facility will have to be installed on the power station site for the storage of solid radioactive wastes and concentrates. Final storage will be in a collective storage facility owned and operated by the State.

On-site storage of irradiated fuel

The irradiated fuel store shall be dimensioned only for temporary storage of fuel elements prior to off-site transport to a collecting store or to the reprocessing plant. Additional storage capacity for the discharge of a whole reactor core shall be provided.

Capacity of power station workshops for non-contamined equipment

Suitable workshops for performing major repairs on all parts of the equipment exist in the nearby large city or within a larger radius from the power station site. However, to keep plant availability high, an adequate workshop capacity is to be provided on the station site. For the size of these workshops, the following useful areas shall apply as guiding values with a unit of 250 to 500 MWe.

Mechanical workshop	approx. 400 m^2
General electric shop	» 50 m^2
Instrumentation and electronics workshop	» 80 m^2
Other workshops	» 100 m^2

In addition, a store for spare parts and shop materials adapted to these workshops shall be provided.

Accommodation of non-local labour

A construction labour camp for the whole construction period of a capacity of 250 men including a canteen shall be provided near the site. The construction management staff may be accommodated in the surrounding towns and villages, so that no special housing units may be constructed for this purpose.

Local labour availability

Throughout the construction period availability of local skilled and auxiliary labour may be expected to be adequate within a radius of 1 hour of transport time from site. Transport facilities shall be provided for part of this labour force.

Work week

All work on site during the construction period will be based on a 40-hour week with overtime allowances as fixed by wage rate agreements.

Utilities

For construction power supply, the site boundary is passed immediately by a 20 kV line able to meet construction power requirements in any case. The cost of this power will be $\frac{15}{1000}$ kWh a.u.

Fuel oil, fuel and automotive workshops are available at a few kilometers distance from the site.

Drinking and process water supply during the construction period must be provided by the construction of a well.

The disposal of sewage and liquid wastes during the construction period will be the construction and erection firms' responsibility.

System connection situation

The nuclear power station is located within the general distribution area of a large electricity supply undertaking. About 4 km away is situated a large 220/110 kV transformer and switching station to whose 220 kV busbars the power station is to be connected. A 220 kV overhead line connects the high-voltage terminals of the main generator transformer with the switching station. In addition, a 110 kV station service start-up line leads from the substation to the power station.

Permanent staff housing

Due to the major distances from the neighbouring towns and cities, a housing development for 70% of the overall permanent staff shall be constructed together with the power station.

Type of power station design

The site is located in an area where indoor installation of turbo-generators within a closed turbine house is common practice.

Turbo-generator design

C.W. Design temperature 15 °C.

Normally 1 turbo-generator is to be allocated to a single reactor.

If, for reasons of capacity limits or other considerations, the overall capacity is to be subdivided into 2 units, caution must be exercised in drawing comparisons, as the capital cost of a nuclear power station comprising 2 turbo-generators is 3 to 5% higher than that of a station featuring only 1 turbo-generator of the same overall capacity.

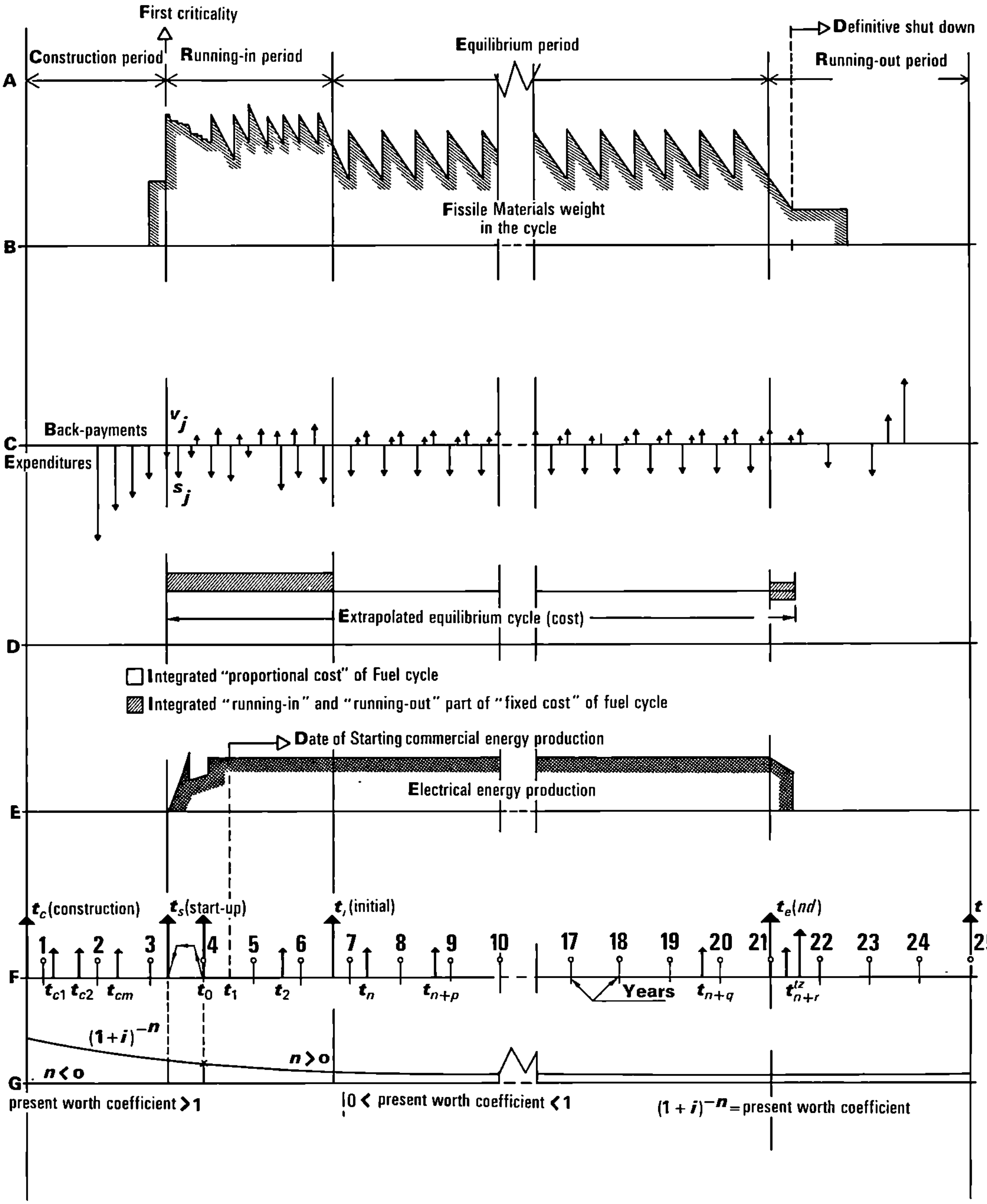

Fig. 1. — Schematic representation of economical, technical and administrative plant life as for the fuel-cycle costing procedure

(a priori method)

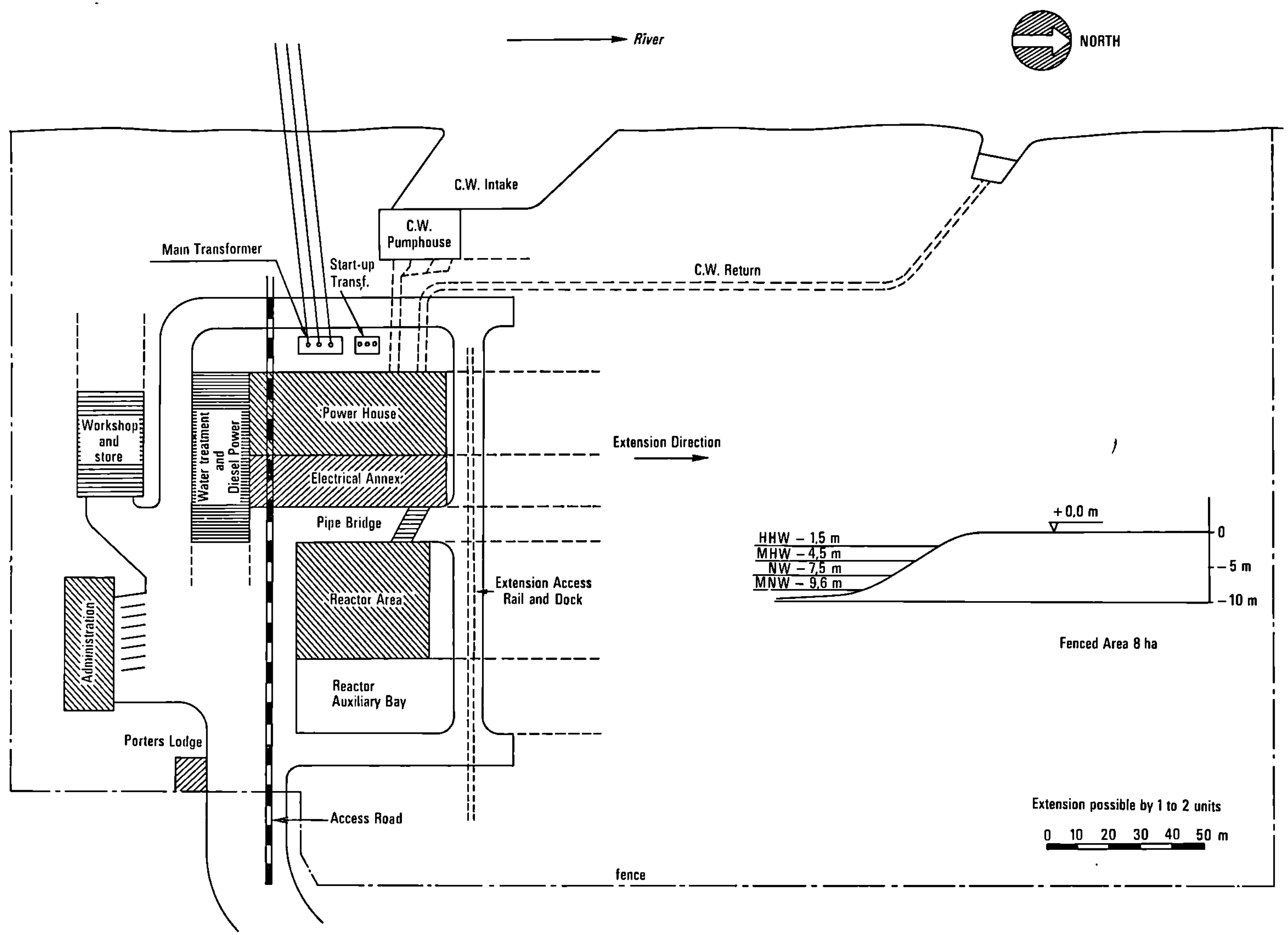

Fig. 2. — Hypothetical site for 300-MW-unit Schematic Layout

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