PUBLIC POWER CORPORATION

GREECE

INTERIM REPORT

ON

ELECTRICITY TARIFFS

BY

D. J. BOLTON, M.Sc., M.I.E.E.

ΕΝΩΣΗ ΔΗΜΟΚΡΑΤΙΚΟΥ ΚΕΝΤΡΟΥ
ΕΔΗΚ

Consulting Engineers:
KENNEDY & DONKIN,
Alliance House,
12, Caxton Street,
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1 INTRODUCTION

1.1 Origin and Terms of Reference

On February 20th, 1963 the Firm were asked by the Public Power Corporation of Greece to make recommendations on their electricity tariffs and to prepare a new rate structure. Although no formal terms of reference were laid down, it was made clear that the problem was two-fold. Namely, to formulate a tariff which would be appropriate to a number of new large industrial loads expected to arise, and to design a single rate structure for the whole of Greece which would replace the two sets of tariffs now operating. It was stated that the first-mentioned was the more urgent of the two.

In earlier discussions in London between Mr. Goustis of the Corporation and Mr. Bolton, and subsequently with other members of the Firm, it was explained that it was difficult to estimate how long the whole work would take, or whether it could best be done in a single operation. It was therefore advisable to arrange a visit as early as possible, and to base future plans on this.

1.2 Visit to Athens

Mr. Bolton went to Athens on May 1st, 1963 and stayed for seven weeks. He had meetings with the Chairman (Mr. Arliotis, now Minister for Co-ordination in the Greek Government) and the General Manager (Mr. Kalimskis). During the whole time he was in constant communication with the Assistant General Manager (Mr. Goustis) and his colleagues, particularly Mr. Apostolakis, Mr. Scaramangas and Mr. Andreadis. He received the utmost co-operation and unstinted assistance from all these gentlemen, and indeed the whole staff, and would like to place on record his thanks and admiration for the way in which they were able to meet him in his language instead of their own.

1.3 Historical and Statistical Background

Electrically, Greece divides naturally into two parts, and it is not surprising that until quite recently these were supplied by two separate utility organisations. On the one hand there is the "Capital" area (Athens, Piraeus) small geographically, relatively well developed electrically, with a fairly dense population and containing almost the whole of Greece's few heavy industries. This has had an electricity supply for nearly 40 years and was served by a company, the Athens-Piraeus Electric Company (APECO). On the other hand, there is the remainder of the Greek mainland and islands comprising most of the area, with a low population density and very low consumption per head. This was served by about 390 separate utilities under municipal or company operation and not interconnected.

This multiplicity of isolated utilities and this duality of organisation was clearly not calculated to enable an economical supply to be given to a majority of the population. Moreover it runs counter to the pattern of distribution of Greece's power resources. These are fairly well scattered, with lignite in the north west and south west, and hydro resources in the mid west, whilst the centre of gravity of the load (Athens) is in the east. To exploit these resources in the most efficient manner, to give country-wide distribution, and to secure a wide latitude in the siting of new industries, a single organisation and a high-voltage transmission and interconnection network was obviously called for.

In 1950 electricity supply in the Provincial area was nationalised by the setting up of the Public Power Corporation. A central (steam) power station at Aliveri commenced operating at the beginning of 1954 and shortly afterwards a high voltage network (150 kV) was established. Since then, the process of interconnection has continued steadily and rapidly. Existing systems have been connected up and their generating equipment (usually diesel) has, where practicable, been transferred to islands, etc. where isolation is at present unavoidable. At the same time, supplies have been given to many smaller towns or villages previously without any public electricity.

In accordance with a Decree of November 1957 APECO was purchased by the Greek Government and with effect from January 1st, 1961 it became part of the Public Power Corporation. This has enabled the continued electrification of the Provincial area to be combined with an integration with an urban complex having a substantial industrial load. This should ultimately lead to economies and greatly improved facilities on both sides.

In the meantime it would be difficult to exaggerate the size of the task which has been accomplished, and of that which still remains. As regards the former, there are now about 1400 towns and villages supplied by the Corporation. In a single year, 1961, 107 separate systems were connected to the national supply, and a further 137 towns and villages were given a supply for the first time. In this one year therefore there were 244 towns and villages added to the list of those serviced by the Corporation.

For the future, a three-and-a-half fold increase in total supplies is being prepared for in the ten-year period to 1972. To meet this huge increase, four major new power stations have been planned or started, two steam and two hydro. It is expected that part of the new load development will consist of certain large, high load-factor, loads representing a type of development not at present existing in Greece.

In addition to the technical integration described above, and now largely accomplished, there must, of course, be a corresponding integration on the commercial and financial sides. This involves uniform systems of costing and accounting which will make possible a uniform tariff schedule. At present the two areas are continuing to operate their individual tariff systems exactly as before the merger, and the following Table(1) will indicate the proportion of the two electricity systems as in 1962.

TABLE 1

ELECTRICITY PROPORTIONS

Area	Electricity Sales	Revenue	Number of Customers	Population Served	Consumption per Head of Population Served (kWh) 1961
Capital	67.5%	65.8%	41%	37%	767
Provincial	32.5%	34.2%	59%	63%	198
Total (Actual Magnitudes)	2295×10^6 kWh	2100×10^6 Drachmas $= 25.2 \times 10^6$ £ Sterling	1 279 920	4.98 Million (Total Population 8.4 M.)	410 (Per head of total Population: 250)

1.4 Assumptions and Procedure

Before making a cost assessment and a set of tariff recommendations it is necessary to make certain basic assumptions and to agree them with the Corporation's management. These concern such things as the financial target to be aimed at, and the magnitude and method of depreciation provision. Since the new tariffs are required to serve for a number of future years it is also necessary to aim at some particular future year and to agree on load and cost estimates for that year.

During the visit, by means of meetings and exchange of memoranda, agreement was reached on all these main issues. At the end of the visit it was possible to make an interim recommendation for a tariff for the new large industrial consumers.

1.5 Data Employed

Printed annual reports were available for a number of years up to and including 1961. These reports contained a fully documented record of all the essential engineering and financial statistics relating to the Corporations' operations. During the visit most of the corresponding figures for 1962 were made available.

1.6 Ten-Year Forecast

A very detailed and comprehensive forecast has been prepared for the ten years 1963 to 1972 inclusive. (Referred to hereafter as the 10-year forecast). A copy of this was made available, and a tribute must be paid to the thoroughness and precision of this document. The main schedules comprised in the forecast are the following. (In every case figures are given for each of the ten years).

Energy sales to each class of consumer, and system maximum demand.

Revenues from each consumer class.

Generation requirements and sources of supply.

Profit and loss accounts showing operating expenses, capital charges and surpluses.

Balance sheets.

Construction costs on power stations, transmission lines and substations, distribution.

Extent of capital expenditure covered by surpluses ("self-financing") after meeting debt services (interest and repayment).

1.7 Contents of Interim Report

The present Report, which is of an interim character, comprises the following :

(i) A complete analysis of the costs, leading to a set of cost formulae.

(ii) A preliminary load study containing the material for estimating the load factors and demand responsibilities of different consumer groups.

(iii) A recommended tariff for new large industrial consumers.

(iv) A suggested tariff for high tension industrial consumers of the existing type, together with recommendations for trials to be carried out in order that final recommendations can be made.

(v) A discussion of the types of residential tariff appropriate to Greece, and an indication of what will require to be done before recommendations can be made for these and other low tension consumers.

2 FINANCIAL STATISTICS

2.1 1962 Revenue Account

In the yearly operating statement the activities of the Corporation are regarded as occurring in two sectors, namely, generation and (main) transmission, and distribution. The generation and transmission sector produces electricity and sells it to the distribution sector. The distribution sector buys electricity from the generation sector and sells it to the consumers. Each sector shows a balance or surplus on its transactions. The capital charges are debited to each sector according to the plant employed. The management and common expenses are apportioned in some unstated manner.

This division into two so far as the costs are concerned has many advantages and is particularly useful for tariff costing. But the division into two in the profit and loss account appears to have little meaning. The amount which the distribution sector pays to the generation sector for the bulk supplies appears to be an arbitrary figure, and if this were changed the balances of the two sectors would be altered although the overall surplus would be the same as before.

In the following simplified statement (Table 2) the similar elements in the sectors are coupled together and the final column shows the overall effect when the two sectors are merged into one.

TABLE 2

CONSOLIDATED OPERATING STATEMENT FOR 1962

(see page 6)

The outstanding feature of this account is the size of the net income or surplus which is 23.4% of the turnover. This is not an accident of a particular year but is a figure which has been steadily approached for some years past. The corresponding percentages for the four previous years 1958 to 1961 were : 2.8%, 11.5%, 12.1% and 21%. The main reason for this is that rather more than half of the Corporation's capital has been provided free of interest. (This is referred to later under the heading "revenue target"). A secondary reason for the high surplus is that depreciation provision has been at a somewhat low rate.

TABLE 2

CONSOLIDATED OPERATING STATEMENT FOR 1962
(Thousands of Drachmas)

	REVENUE	DETAILS	TOTAL
1	Retail Sales	2 071 610	
2	Bulk Sales to Utilities	34 554	
3	Direct Supplies	3 321	
4		2 109 485	2 109 485
5	Add Other Operating Revenues	17 771	17 771
6	Total Revenue from all sources		2 127 256
	EXPENSES		
7	Headquarters, Generation and Transmission	11 314	
8	Generation, Direct Expenses	643 722	
9	Transmission, Direct Expenses	32 138	
10	Total, Generation & Transmission	687 174	687 174
11	Distribution, Direct Expenses	353 342	
12	Purchase from Naval Arsenal	327	353 669
13	Depreciation, Generation and Transmission	148 584	
14	Depreciation, Distribution	121 064	269 648
15	Administration and General, G & T.	13 667	
16	Administration and General, D.	21 269	34 936
17	Interest and Financing, G & T.	188 180	
18	Interest and Financing, D.	95 866	284 046
19	Net Income, G & T sector	242 172	
20	Net Income, D sector	255 611	497 783
21	Total Outgoings		2 127 256

2.2 1962 Balance Sheet

The statement shown in Table 3 is a simplified form of the balance sheet for December 31st, 1962. This omits all the items which cancel out (in whole or in part) in respect of the capital required to operate the utility. The accounts owing and the accounts receivable are only shown to the extent of their net difference. The balance therefore shows the net capital actually and necessarily employed (except possibly for the relatively minor item of investment holdings).

TABLE 3

SIMPLIFIED BALANCE SHEET AS AT 31.12.1962
(Millions of Drachmas)

	ASSETS	DETAILS	TOTAL
1	Plant in Service	8 872.0	
2	Work in Progress	1 466.0	
3	Intangibles, etc.	90.7	
4	Total Utility Plant	10 428.7	10 428.7
5	Less Depreciation Reserves	1 226.1	
6	Net Worth of Plant	9 202.6	9 202.6
7	Supplies, Materials and Net Outstanding Orders	821.7	
8	Current Assets less Current Liabilities	328.4	
9	Deferred Debits less Deferred Credits	553.4	
10	Investments, etc.	246.5	
11	Total Current Assets and Debits	1 950.0	1 950.0
12	Total Assets, Lines (6) + (11)		11 152.6
	LIABILITIES		
13	Long-term debt carrying interest		5 149.7
14	Customers and Collectors Deposits		137.3
15	Contributions of Greek Government	4 319.8	
16	Customers Contributions	234.4	
17	Reserves (excepting Depreciation) and Various Capitalizations	102.6	
18	Capitalized Surplus	1 208.8	
19	Total Capital and Surplus	5 865.6	5 865.6
20	Total Liabilities		11 152.6

The outstanding feature of this account is the low value of the depreciation reserve, which is only 13.8% of the asset cost whereas a more usual figure would be in the range 30% to 40%. This is attributable to two things namely a comparatively low rate of annual depreciation provision and a short period of average life expiry. Owing to the rapid growth of capital expenditure and the absence until recent years of large central generating stations there is a preponderence of new and fairly new capital assets. Hence the fund accumulated for their replacement is small.

On the other hand there is a reserve of about the same magnitude described as "capitalised surplus". These two can be grouped to the extent that they both represent amounts that have been saved out of current expenditure and employed in the financing of new capital works. This extent of what is called "self-financing" has been made possible without increasing the price of electricity owing to the low overall rate of interest already referred to.

Two other figures in the balance sheet differ from average. The figure for work in progress is a higher proportion than usual of the plant in service. This is due in part to the high rate of construction and in part to a delay in having the accounts transferred. The figure for current assets, namely about 21% of the net fixed asset cost, is also unusually high.

2.3 Depreciation Provision

The annual provision made for depreciation has not yet been fully unified as between the assets taken over from APECO and those which belonged to the Corporation in the first place. For example, on steam-electric plant the depreciation in 1962 as a percentage of first cost was higher (representing a shorter life period) with APECO than with P.P.C. plant. On the whole, the Corporation appears to have been guided largely by American practice, and in particular Bulletin "F" of the U.S. Treasury. The life periods there indicated are in general longer than those in European practice, and it is noteworthy that a later American publication No. 456 (7/62) dated July 1962 substitutes a new set of lives stated to be on the average 30 to 40 per cent shorter.

The matter was discussed at some length with the Corporation's officers, and it was finally decided to adopt, for purposes of tariff costing, the life periods shown in Table 4. It is further assumed that the provision will be made on a straight line basis - i.e. by equal annual amounts equal to the asset first cost divided by the life in years.

These life periods are wherever applicable identical with those employed for the same purpose in Great Britain. The following are the main reasons for choosing these figures.

(a) They represent the accumulated wisdom of some eighty years experience of publicly owned electric utilities, municipal and national.

(b) They have been adopted by a number of other government-owned utilities in various parts of the world.

(c) They are generally in line with, though not necessarily identical with, good modern practice elsewhere.

Owing to differences of classification or grouping it was not always possible to supply an appropriate figure from the U.K. schedule. These cases are indicated by letters with footnote references.

TABLE 4

LIFE PERIODS FOR DEPRECIATION PROVISION

	Life in Years
Hydro-electric stations and equipment	65 (1)
Steam-electric stations and equipment	25
Diesel-electric stations	12 (2)
Transmission lines	40 (3)
Distribution lines, H.T.	35 (3)
Distribution lines, L.T., consumer services, meters and equipment	25
Transmission and distribution substations	25

(1) The usual practice with hydro-electric stations is to employ a longer life than 65 years for the civil engineering construction and a shorter life for the water-wheels and alternators. In the present case this degree of complication did not appear justified, and a weighted average was substituted. The figure used is the one which has already been employed by the Corporation in costing the Kastraki project.

(2) In the absence of a figure in the schedule referred to, this figure is employed.

(3) A common practice is to allow 40 years for underground cables and 30 to 40 years for overhead lines and towers. This latter figure will depend to some extent on the policy pursued regarding maintenance. Thus if restringing of lines is charged to maintenance a longer period can be allowed for depreciation.

The only substantial difference from the present practice of the Corporation arises in the use of a 25-year period for steam generating plant and electrical equipment generally. Some of these assets are at present depreciated over periods up to 34 years, and it must be emphasised that the shorter period is essential if obsolescence risks are to be covered. The extent of this risk can be very well seen by comparing the average fuel cost per kWh generated in 1962 with the figure forecast for 1966. This shows a drop to less than two-thirds in four years which is a measure of the improved efficiency obtainable through larger sets and higher steam conditions. Technological progress will continue, and provision must be made such that plant can be economically replaced or relegated to lower rank usage before the end of its physical life.

2.4 Revenue Target : Return on Capital

The new tariffs must have a target as regards the overall revenue which they aim to procure. They must, of course, cover working costs, management and depreciation, and they must give a satisfactory return on the capital employed. It is therefore necessary to see what is the present capital return and what is the return in future years as shown in the forecast. It is then necessary to ask whether this return can be regarded as the right one or whether it is excessive or inadequate. The answer to these questions will indicate what the future tariff revenue should be.

A minimum requirement is of course solvency, but it would be a mistake to aim merely at meeting the actual expenses and capital charges incurred. In the Corporation's case a considerable proportion of the capital at present employed is interest free, and if the revenue were only sufficient to service the remainder of the debt it would mean that a proper and adequate return was not being earned on the real capital resources which were being utilised. This fact has been recognised in the past, and it has been the Corporation's policy to earn each year a substantial surplus over the immediate interest requirements.

In setting a target for future years, much depends upon how the figure is to be expressed and on what basis it is to be reckoned. It seems preferable to express a gross return before depreciation provision has been deducted rather than a net return after providing for depreciation. This enables systems using different methods of depreciation provision to be compared on a uniform basis. When the provision is by way of a sinking fund, which is then coupled with interest on the full amount of the first cost, the interest component of the capital charge is greater and the depreciation component is less than it is when the provision is by way of straight-line allocations, coupled with interest on the outstanding balance. An overall return which includes both interest and depreciation then provides a better guide to the situation, and this is the practice of the British nationalised electricity system where the "target" is a return of 12½%.

The other point of difficulty concerns the question of what is to be regarded as the "net" capital upon which this "gross" return shall be earned. The figure of capital shown in a balance sheet is usually swollen considerably beyond the true value of the net capital because it includes items such as "accounts receivable" on the one side, and "accounts payable" and other obligations, on the other side. These to a large extent cancel out and do not necessitate capital. Apart from these smaller items, the main item on the assets side of the balance sheet is the expenditure on fixed assets. This is partially off-set by an accumulated depreciation reserve on the other side of the balance sheet, or alternatively by an immediate deduction leading to a lower value for the assets, sometimes termed the written-down value.

The proportions of the above figures will greatly affect the calculation which is made of the "return" on the capital employed. For example, in Britain the depreciation reserve is approximately 35% of the asset first cost. There is only a very small proportion of working capital in addition to the assets. Hence the "return" of 12½% is only reckoned on a total of some 65% of the assets cost. In the Corporation's case owing in part to a very rapid growth and a preponderence of new assets the depreciation reserve at 31.12.1962 is less than 12% of the asset cost, and there is a further addition of about 18% to the net asset cost for working capital.

In setting a target for future years it is necessary to make some assumptions regarding depreciation provision so as to know what figure the return will be reckoned on. There are three possible assumptions namely

(a) A continuance of the present practice regarding depreciation provision. This seems most unlikely because the present practice differs as between the Capital and the Provincial areas.

(b) The adoption of new rates of depreciation (based on the life periods shown in Table 4) starting with the depreciation allocations for 1963. This would result in a depreciation reserve which built up at a somewhat higher rate than at present but at a low rate nevertheless because of the rapid capital expenditive.

(c) New rates as under (b) and in addition a retroactive adjustment of the depreciation reserve up to the figure which it would have reached had the new rates been employed from the commencement. This re-adjustment would not be so devastating as it sounds - it merely means that certain sums would appear under the heading "depreciation reserve" which formerly appeared under the heading of "capitalised profits".

Taking the revenues and expenses shown in the 10-year forecast the results have been worked out under assumption (b) and alternatively under assumption (c) for the two years 1966 and 1972. Owing to the very rapid rate of capital development during both these years it is reasonable to assume that a certain proportion of the assets whose cost appears under "work in progress" would in fact be in operation and subject to depreciation provision during a part if not the whole of the year in question. On the other hand, some of the "plant in service" at the end of any given year will not have been in this account for the whole of the twelve months.

It is assumed that these items cancel out, and that in any year it will be correct to associate twelve months' depreciation provision with the total depreciating plant cost shown to be in service at the end of the year. After deducting the depreciation reserve from the asset cost, an increase of 10% was made for working capital, since it appeared from present experience that something of this size would be required for future operations.

The results are summarised in the following table :

TABLE 5

FORECAST OF GROSS RETURN ON NET CAPITAL EMPLOYED

	1966	1972
Assumption (b)	10.9%	12.5%
Assumption (c)	11.2%	12.7%

In any plan for the future it is necessary to weigh up the various pros and cons. In the present case if too low a return is budgetted for, there is a danger that scarce capital resources will be employed at less than their proper rate. Electricity users will then be benefitting from a hidden subsidy, and it is possible that there has been some element of this in some of the existing rates.

If too high a return is aimed at, it means that present electricity consumers will be to some extent subsidising the future ones. On balance, it would appear that the above figures represent a desirable middle position between these two extremes. The revenues indicated in the 10-year forecast have therefore been accepted as the target of the new tariffs.

3 ENGINEERING STATISTICS

3.1 Consumer Classes and Consumptions

Statistics of consumptions and revenues are still being recorded separately for the Provincial area and for the Capital area (late APECO). This separation is inevitable whilst separate tariff schedules are in operation, and it will be necessary to use these separate figures when planning the transition to a new schedule. In future years, however, it does not appear that the compilation of separate figures for the two areas will be necessary, or even desirable. Since the whole system is to operate as a single utility, and since a common tariff schedule is proposed, it seems better to group the consumers and their loads according to the tariff categories under which they will be supplied, and not to complicate the picture by a further division into areas.

In Table 1 a territorial division was employed in order to provide the historical background, but the tables which follow are more forward-looking and the area division has been submerged in the more technical classification and groupings.

TABLE 6

CONSUMPTION STATISTICS, 1962

Consumer Class	Tariffs		Proportions of		Mean Revenue Lepta Per kWh	Number of Consumers
	Capital	Provincial	Sales	Revenue		
Residential	T1 to T4	T9	35.7%	49.4%	127	1 060 657
Industrial H.T.	A1 to A5	T23	38.8%	23.1%	54	607
Industrial L.T.	K1 to K3	T19	11.6%	11.7%	92	38 954
Industrial total			50.4%	34.8%	63	39 561
Commercial	Offices	T19	9.0%	11.6%	118	163 184
Traction	Special	None	1.8%	1.7%	82	3
Street Lighting	Special	T49	1.6%	1.4%	82	3 146*
Irrigation	None	T33	1.5%	1.1%	66	13 369
Total			100.0	100.0	91.5	1 279 920
SUMMARY						
Residential			35.7%	49.4%		
Industrial, Traction and Irrigation			53.7%	37.6%		
Commercial and Street Lighting			10.6%	13.0%		
Total			100.0	100.0		

* Number of metering points.

It will be seen from the upper part of the table that, of the two major consumer groups, the residential account for about half the revenue and 35% of the consumption whilst the industrial accounts for half the consumption and 35% of the revenue. Together they account for about 85% of both sales and revenue, the remaining 15% being for commercial uses, offices, shops, etc., and for traction and street lighting and irrigation.

3.2 Load Growth

With most utilities it is possible to study the load growth over, say, the last five or ten years and to analyses this growth into its two components - growth in number of consumers, and growth in consumption per consumer. Curves of load growth for different consumer groups can then be extra-polated for purposes of a forecast of future growth.

In the present case this is difficult and may prove unreliable for two reasons. In the first place the joint operation of the Corporation's original Provincial area with the Capital area taken over from APECO dates only from January 1st, 1961. Previously the two organisations employed quite different accounting methods as regards both investments and operating expenses, they operated entirely different tariffs with different classifications and definitions of consumers. Moreover if, for example, an earlier year of APECO is compared with the 1962 consumptions and consumers in the APECO area there are difficulties because certain districts on the fringe have been switched from P.P.C. to APECO operation and accounting whilst still retaining their old tariffs.

The other difficulty is that in the Provincial area the process of buying out existing independent utilities and connecting them where possible to the national network has been going on rapidly, and side-by-side with the giving of a supply to towns and villages previously without one. For example, in 1961, 44 electric utilities were purchased by the Corporation of which 10 were in Continental Greece and 34 in the Islands. This taking over of existing utilities is now virtually completed; the addition which it makes to the energy sales and the number of consumers is a non-recurring type of load growth which adds to the difficulty of forecasting.

These difficulties in the detailed study of consumers and load growth in the two areas do not arise when looking at the total electricity consumption in Greece as a whole. When this is done, the picture is one of steady and rapid annual growth. Taking the eight years from 1955 to 1962 involving seven annual increases the percentage growth has never been less than 8% and has reached twice this figure. The mean annual increase over the whole period has been 12½% - i.e. this is the figure which, had it occurred every year, would have given the total increase that actually occurred.

In the 10-year forecast the consumption figures appear to assume an annual growth from existing consumer classes of about 10%. In addition there are some half-a-dozen potential large new industrial loads, the largest of which (Aluminium) has already concluded a contract. It is estimated that by 1972 their loads will represent an addition of between 35 and 40 per cent to the routine loads of the types now existing. The overall growth will represent an increase of some three-and-a-half times in the ten years from 1962 to 1972.

As percentages these figures may seem high, but the starting figures to which they apply are low in relation to the population and in comparison with other European countries. Moreover they have been backed by a comprehensive programme of generating station construction which should ensure that the load, as it develops, will not be throttled by lack of capacity to meet it.

3.3 Maximum Demand and Load Factor

In expressing the annual load factor of the interconnected system it is best to express this as a ratio between the output in a given year and the maximum demand during the winter at the end of the year. This maximum might occur in December or in January, and if the load factor is calculated on a purely calendar-year basis this maximum would be associated with different years' consumption in the two cases. By using the winter peak as a criterion this difficulty is avoided and more consistent results are obtained. This plan is followed in the 10-year forecast and will be followed here.

The system maximum demand in the calendar year 1962 was 537.6 MW but the maximum for the 1962/63 Winter was 552.1 MW both of which figures include an allowance of about 2 MW for certain very small hydro stations which have no telemetering. Relating this to the total system energy (sent out of stations plus purchase) gives a system load factor for 1962 of 54.8%. (The calendar year load factor was 56.3%).

In the 10-year forecast it is assumed that the load factors of existing consumer classes remain approximately the same as at present. As regards the large new industrial loads which are anticipated, figures for the consumption and demand of the largest of them (Aluminium) are known, and estimates for five others have been made. Combining these loads with those of existing consumer classes gives a load factor rising steadily to 64.1% in 1972.

3.4 Generation Resources and Development

Greece is well provided with indigenous energy resources in the form of lignite deposits for steam raising and hydro-electric potentialities. These two kinds of resource have been developed side-by-side for supplying the national interconnecting network whilst diesel stations have supplied the isolated systems on the mainland and the islands. Now that 95% of the country's supplies come from the network it will be sufficient to study power resources only in connection with this network.

Future development is planned along similar lines, with new steam stations alternating with new hydro capacity. One reason for this alternation is to preserve a balance in the matter of load factor. A hydro scheme is designed to operate at a particular annual load factor although there may be fluctuations year by year depending on the rainfall. In a purely hydro system this load factor has to be governed by the load factor of the load to be supplied, but in a mixed hydro and thermal system a more economical arrangement is to

design the hydro scheme for its optimum economic load factor depending on its natural situation. The difference between this load factor and that of the load can then be made up by thermal generation. Thermal stations have the advantage of flexibility, and the load factor can be varied from year to year at no greater cost than the cost of the fuel.

The situation in Greece is broadly that the existing hydro stations have an overall annual plant factor of about 27% whilst the two projected stations will have ultimate plant factors of 42 to 45%. With a system load factor rising from 54% to 64% this means that the steam stations which make up the balance will have to operate at substantially higher load factors than this. One consequence which is of importance from the costing point of view is that extra energy demands resulting from higher consumer load factors can only be met by additional thermal generation.

A slight variation in this pattern is provided by the new hydro station at Kastraki. Initially developed with a view to supplying the aluminium load (load factor 91%) it will have an initial capacity of 160 MW and a corresponding annual plant factor of 63%. Provision has beenmade for the installation of a third 80 MW set at a later date which will enable it to operate at a 42% plant factor representing its optimum natural characteristics. The third set whose output will not be required by the aluminium works will be able to provide peak load service for the system.

The foregoing description can be supported by figures as shown in Table 7. In the absence of separate maximum demand readings at the different stations it is not possible to give the actual yearly load factors (ratio of energy to maximum demand). The table does however give the annual plant factors (ratio of energy to installed capacity). These will be sufficiently close to the load factors to illustrate the balance of hydro and thermal generation. The capacities shown are the installed capacities in the case of the hydro plant, and the net output capacities (after deducting power used on site) in the case of the thermal plant.

TABLE 7

GENERATING CAPACITY (INTERCONNECTED SYSTEM)

(see page 17)

TABLE 7

GENERATING CAPACITY (INTERCONNECTED SYSTEM)

Approximate Date	Hydro Stations			Steam Stations			Total MW
		Added MW	Total MW		Added MW	Total MW	
	Tavropos	120		St.George's Bay	125		
	Ladhon	70		Aliveri	75		
	Agra	50		Ptolemais I	65		
	Louros	10		New Faleron	72		
	Four small	5					
Present			255			337	592
1963				Ptolemais II	115	452	707
1964	Edesseos	28	283				735
1965	Kremasta	400	683	Liptol	30		
				New Faleron out	72	410	1093
1966				Ptolemais III	115	525	1208
1967	Kastraki	160	843				1368
1969				Megalopolis I	115	640	1483
1971				Megalopolis II	115	755	1598
1972	Topoliana	136	979				1734
1972?	Kastraki (3rd)	80	1059				1814

3.5 Generation Operation

The results of this side-by-side build-up of generating capacity can be seen when the operation programme is examined. The aim will be to make the utmost use, each year, of the hydro capacity, where additional generation (up to the limit of water availability) adds virtually nothing to the costs. The balance of energy requirements will then be made up by steam generation. The overall result will be that the proportion of hydro generation will increase from the 1962 figure of 23% to a maximum of about 52% around 1967 and will then fall slightly to 41% in 1972.

There is no point in tracing this process precisely from year to year. Moreover the dates, especially in the later years, are necessarily uncertain. It is, however, useful to take "spot readings" in certain years in order to see how the two types of plant are being utilised. The results throw light on the allocation of generation costs.

The following Table 8 lists four of the years whose costs have been given special consideration in the costing analysis. It is noteworthy that in the future years the plant factor of the hydro stations is a constant figure, indicating that they are being operated throughout at their optimum load factor. The plant factor of the steam stations rises somewhat between 1962 and 1966 due to the addition, on the system, of hydro stations of higher load factor than the earlier ones. Subsequently the steam stations plant factor rises because, over this later period, new loads are being acquired of higher load factors than that of the new hydro stations. (N.B. Kastraki 3rd set is excluded from this list as its installation date is uncertain).

TABLE 8

GENERATION OPERATION (INTERCONNECTED SYSTEM)

	1962	1966	1967	1972
Hydro Generation 10^6 kWh	599	2540	3140	3640
Hydro Capacity MW	255	683	843	979
Hydro Plant Factor %	26.9	42.5	42.5	42.4
Steam Generation 10^6 kWh	1985	2952	2955	5240
Steam Capacity (net) MW	337	525	525	755
Steam Plant Factor %	67.3	64.2	64.3	79.3
Proportion of Hydro Generation %	23.2	46.3	51.5	41.0

3.6 System Load Curves

(As in the previous sections this study concerns only the interconnected system, comprising about 95% of total supplies). System load curves were examined for the day of annual peak in 1962, namely, Friday December 21st. In order to study seasonal variations, load curves for the same day of the week (Friday) were examined at three-monthly intervals throughout the year. In the case of the peak day, December 21st, separate curves were examined for the Capital and Provincial areas, and the diversity between them was calculated. Some of the numerical results are given in Table 9. A detailed load analysis has not been made, and the following comments refer to points which are of importance in tariff costing.

None of the load curves show a sharp-pointed peak of short duration such as occurs in many countries due to the overlap of an industrial and a residential lighting load. The maximum loads usually lasted for several hours and represented plateau rather than peaks. Almost always there is a secondary peak or "near peak" of not much less than the peak magnitude but at a different time of day. One of these occurrences was from 11 to 12 hours and the other was between 18 and 21 hours (6 to 9 p.m.).

In the total system load curve, the morning peak was the greater in all but the September curve. When the peak day curve was split, the capital component showed a well pronounced morning peak whilst the provincial area showed a pronounced evening peak.

Under these circumstances it would clearly be incorrect to allocate demand-related costs on the basis of a narrowly-conceived "peak responsibility" theory. Instead, it is necessary to regard considerable periods of the day as being "peak liable" and to assess liability for demand-related costs according to the loads in this "potential peak period". If such periods are defined as those in which the load curve is more than 75% of its maximum (yearly) height, the potential peak period in December would appear to be between 8 and 15 hours and between 17 and 22 hours (12 hours in all). Outside these hours, peaks appear most unlikely to occur. At week-ends and outside the winter months the potential peak periods would be shorter or non existent. A more detailed study than this would be necessary in determining times for off-peak tariffs or for reduced kilowatt charges.

TABLE 9

SYSTEM LOAD CURVE 1962

Day	Peak Time	Secondary or Near Peak		Daily Peak	Daily
		Time	Magnitude % of Peak	% of Annual	Load Factor
Fri. March 30th	11 to 12	19 to 20	98.6	76.5	64.6
" June 29th	11 to 12	20 to 21	85.0	76.2	71.1
" Sept. 28th	19 to 20	11 to 12	96.3	83.5	69.7
" Dec. 21st	11 to 12	18 to 19	97.5	100.0	69.8
" " Capital	11 to 12	18 to 19	91.4	69.4	
" " Provincial	18 to 19	11 to 12	89.4	34.1	
				103.5	

N.B. It is noteworthy that the Capital area has a morning peak and the Provincial area, with a much smaller industrial load, has a late afternoon peak. Since each area has a near peak in the other time, the diversity between them is not great. In figures it is 103.5 divided by 100 = 1.035.

3.7 Weekly and Seasonal Variations

Since the daily load factor for the peak day of 1962 was 69.8% and the yearly load factor was 56.3% (omitting in both cases the effect of the small unmetered stations) the closeness of these two figures shows that there cannot be very large seasonal variations or week-end reductions. The smallness of the seasonal fluctuations can also be seen by examining the monthly variations in energy generation and maximum demand.

Figures for the total net generation and maximum demand were obtained for each month of 1962 for the interconnected system. Since there is a continual growth in load it is necessary to adjust these figures in some way in order to eliminate the growth element and study only the monthly variations. The method of adjustment employed was to assume a yearly increase of 10% and to assume that this took place by a uniform amount each month. This amount would then be $^{10}/_{12}$ per cent - i.e. 0.833% of the January figure. This quantity was therefore subtracted from the February figure, twice this quantity was subtracted from the March figure, three times as much from the April figure, and so on.

The resulting "adjusted" figures for both energy and demand show a fairly steady drop during the earlier months of the year (January to May), a fairly steady constant value from May to September, and then a steady rise to December. The load factor tended to be lower in the peak months of December and January, and higher in the summer months, with the result that the fluctuations of demand were greater than the fluctuations of energy.

In figures, the total range of variation, as measured by the difference between the highest and lowest readings divided by the average reading was 18½% for the energy curve and 26% for the demand curve. The ratio between the sum of the twelve readings and the highest of the twelve was 10.75 for the energy, and 10.6 for the demand. These figures can be compared with those in the last line of Table 10 below.

The absence of large seasonal variations is doubtless partly due to the smaller variation between summer and winter daylight hours (as compared with countries further from the equator) and to the absence of any large electric space heating load. Looking ahead, there is even the possibility that with rising standards of living and the growth of air conditioning and irrigation the peak might occur in the summer. Off-peak rates must bear this possibility in mind, and it also has a bearing on the question of monthly and annual maximum demand assessments in two part industrial tariffs.

3.8 Individual Power Consumers

The above study was supplemented by an examination of the records of a number of individual consumers on two-part maximum demand tariffs in the Capital area (Tariffs A1 to A5). In order to get a range of sizes, a random sample of ten consumer was taken out of the 197 consumers on Tariff A1. At the other extreme, the whole of the five consumers on A5 were examined. Attention was particularly directed to the monthly maximum demand readings.

As regards seasonal characteristics it was found that, out of the 15 yearly maxima, four occurred in February, three in December, two each in January, August and October, and one each in April and July. (The total of sixteen is due to one maximum having been repeated in a second month). The three winter months, December to February inclusive therefore included nine out of the sixteen maxima.

When the actual figures are examined, this seasonal variation proves to be only slight. The results are summarised in Table 10 which has been included partly to illustrate the use of sampling methods referred to in a later chapter. One point to note in this connection is that when a particular quantity can be evaluated for both the sample and the whole population, e.g. the main consumption per consumer, lines 2 and 5, the closeness of the two figures is an indication that the sample is representative. (Under tariff T5, since the sample equals the whole population, the figures should be identical. The discrepancy probably arises because in the total returns only the bills issued were taken into account and not the materialised receipts). The figures in the last line are made use of in connection with monthly and annual demand assessments.

TABLE 10

INDIVIDUAL H.T. CONSUMERS

Line	Tariffs	A1	A5
1	Number of consumers on tariff	197	5
2	Mean consumption per consumer (Thousand kWh)	272	25 330
3	Mean revenue per kWh (Lepta)	74.4	47.2
	(The following lines refer to the sample)		
4	Number of consumers in sample	10	5
5	Mean consumption per consumer (Thousand kWh)	280	26 600
6	Mean monthly M.D. per consumer (kW)	69.95	4 904
7	Mean monthly load factor	45.6%	62.0%
8	Mean monthly aggregate M.D. % of maximum	84.6%	89.3%
9	Ratio of aggregate monthly M.D.'s to annual M.D. (line (8) x 12)	10.2	10.7

3.9 Loads of Consumer Groups : Capital Area

The results were made available of a study that had been carried out on the loads of different consumer groups in the Capital area. These refer to the component loads which made up the total Capital area load on the peak day of 1961, namely December 20th. The results were presented graphically in the form of 24-hour load curves for each consumer group but it is not known how these were obtained. The aggregate curve for the whole area had a peak at 11.30 hours, and a near peak, 94% as high, at 18.30 hours. It follows that the behavour of the component curves at these two times is particularly important. The results are summarised numerically in the following table. (N.B. as certain of the values were read off the graphs, the figures are only approximate).

TABLE 11

COMPONENT LOADS ON PEAK DAY, CAPITAL AREA

Consumer Class T	Tariffs	Daily Energy MWh	Daily Demands, MW			Effective Daily Load Factor
			Maximum	At 11.30 Hours	At 18.30 Hours	
Lighting, Etc.	T1, T4	1 202	115.0	54.5	114.5	43.7%
Cooking, Heating, Lighting.	T2, T3	1 700	120.0	120.0	91.0	59.0%
Municipal Lighting.	Special	50	3.0	0	3.0	69.5%
Power, L.T.	K1, K4	558	64.5	62.5	23.5	37.2%
Power, 6.6 kV	A1 to A4	1 540	86.5	85.7	64.5	75.0%
Power, 22 kV	A5	478	24.0	16.5	21.5	92.7%
Sub-total, H.T. Power	A1 to A5	2 018	110.5	102.2	86.0	82.2%
Traction	Special	128	10.5	6.5	7.0	76.3%
Total		5 656	423.5	345.7	325.0	68.3%

The last column gives the effective daily load factor in relation to the peak time of the system. Since the aggregate curve is nearly as high at 18.30 hours as it is at the absolute peak time of 11.30 hours it is necessary to regard both these times as being potentially (and almost equally) dangerous. In calculating the load factor therefore the higher of the two readings, whichever it happened to be, was taken in each case. The annual load factors will be less in the ratio :- annual consumption divided by peak day consumption x 365. For example, in the case of the H.T. power consumers, if this ratio were 1.17 the effective annual load factor of this consumer group would be 82.2/1.17 = 70%. This is the figure which has been employed in Table 13, Section (4.5).

It will be noted that the aggregate of the individual group maximum demands (423.5 MW) is far greater than the actual simultaneous peak (345.7 MW). The difference represents a diversity factor of 1.225. Moreover there would be a further diversity between the separate consumers within each group.

4 COSTS AND COST FORMULAE

4.1 Procedure

The procedure in this chapter is as follows. A particular target year, 1966, is fixed upon as the aim of the new tariffs. This is judged with the background of the 1962 (actual) figures, and it also takes account of some of the other years in the 10-year forecast, notably 1967 and 1972 (the last year). The complete supply system from power station to consumer is sectionalised into three according to the point in the system at which the supply is taken. A cost structure is then built up for 1966 divided into these three sections. Each cost is allocated according to whether it is proportional to the energy consumption or the maximum demand. These two cost components are referred to as "energy-related" and "demand-related".

A load structure is also built up for 1966 with estimates of the energy consumption and the maximum demand at the three sectional points. The three pairs of cost components are then divided by the corresponding electrical outputs, thus giving three two-part cost formulae. The process is illustrated and the results are given in a series of Tables. (Tables 12 to 19).

4.2 Revenue Aim

As explained in Section (2.4) the tariffs are designed to secure the revenue indicated in the 10-year forecast in relation to the electrical output shown for that year. In the forecast this revenue is shown as being distributed in certain ways - working costs, interest charges, depreciation allocations and undistributed surplus or profit. For tariff costing purposes the whole revenue has to be accounted for - i.e. distributed or allocated in some way that can be attached to the Corporation's activities and services. For the purpose of this allocation the actual interest payments are disregarded, and a notional rate of interest is regarded as being paid on the net capital employed in the business. This rate (which is referred to hereafter as the "yield" on the capital employed) is 6.315%, this being the figure which is necessary to absorb the whole of the surplus remaining from the forecast revenue after paying for depreciation. It is in line with the overall financial target discussed in Section (2.4) and it is a realistic figure in the sense that it covers not only the probability of higher interest rates in the future but also the probability that plant replacements will cost more per kilowatt than the plant they replace.

(N.B. the depreciation provision has been designed to recover only the historic cost not the replacement cost).

4.3 Expenditure : Unit Costs

The costs and other outgoings fall into four groups as follows:

(a) Fuel, oil and other generation materials,

(b) Operating expenses, including repairs, maintenance, purchases and work done by outside contract excepting that charged to capital account,

(c) Management and administration,

(d) Capital charges and disbursements (depreciation and interest or "yield").

Only the first three of these are dealt with in this section.

Detailed cost estimates are given in the 10-year forecast. It would be out of the question to prepare an independent set of estimates, even for the one target year. On the other hand it would not seem right to accept these figures uncritically in every detail, particularly since fresh data may have arisen since they were prepared, such as changes in price levels or wage rates. The following plan has therefore been pursued.

The forecast figures for 1966 are tabulated, and side-by-side are shown the figures for the last factual year (1962). In respect of each group of costs a suitable denominator is then chosen, and the cost is divided by this denominator so as to give a unit cost. For example, for generation costs, the denominator is the energy generated, and the cost is then expressed per kilowatt-hour generated. In respect of transmission and distribution operating costs, these could be regarded as being a function of the energy sold, the maximum demand or the cost of the assets employed (since the staff is largely employed in operating or maintaining the plant). Since, with a steady load factor, these three are roughly proportional it is immaterial which is chosen, and for distribution costs the most convenient, namely energy sold, is employed here. For transmission costs the capital investment is considered to be a more rational basis. Finally, the management and administration costs are regarded as a function of the turnover or total revenue, and are expressed as a percentage thereof.

It must not be supposed that the procedure described above is any substitute for an accurate forecast of the costs. It does, however, throw a certain amount of light upon the forecast that has been made, albeit a superficial one since it lacks inside knowledge of the situation. By using the conception of "unit costs" it enables a rough comparison to be made over the years.

The method can be illustrated by the case of operating expenses. Such expenses increase over the years for two reasons, namely that a bigger number of staff is employed and that rates of pay tend to increase. But both these increases taken together do not, as a rule, mount as fast as the increase in energy sold, maximum demand, or number of consumers. In other words, it is usually possible to deal with double the sales and double the number of consumers without doubling the operating costs. The "unit costs" should then go down.

This achievement of what are called "economies of scale" is not always realised. For example, the Corporation's accounts in the distribution sector for the last five years show the opposite tendency. After deducting the hypothetical sum paid to the generation sector for electricity, the net distribution expenses when divided by the energy sold show the following figures for 1958 to 1962 (Lepta per kWh) : 5.8; 8.5; 8.0; 14.3; 15.0; (These figures include management but not administration. Excluding management the last figure becomes 13 as in the Table below). The large increases in 1961 and 1962 are doubtless partly due to the merging of APECO and P.P.C. In any such reorganisation there is bound to be some overlapping and redundancy, and this can only be corrected over the years without causing hardship by allowing the load to grow without proportional staff increases. Some improvement can therefore be looked for in the next few years but it would be a mistake to be over-optimistic or to suppose that the strong tendency shown by past figures can suddenly be put into rapid reverse.

TABLE 12

UNIT COSTS

(Lepta per kWh except where stated)

	1962			1966		
	10^6 Drs.	10^6 kWh	Unit Cost	10^6 kWh	10^6 kWh	Unit Cost
Fuel (Steam)	368.9	1 985	18.6	361.9	2 952	12.3
Other Operation	128.6		6.5	118.0		4.0
Hydro Operation	22.5	599	3.75	36.8	2 540	1.45
Diesel Fuel etc.	122.7	128	96	208	208	100
		Plant Cost 10^6 Drs.			Plant Cost 10^6 Drs.	
Transmission	32.1	1 238	2.6%	36.0	2 135	1.7%
		10^6 kWh			10^6 kWh	
Distribution Operation	297.9	2 295	13.0	290	3 382*	11.5
		Turnover 10^6 Drs.			Turnover 10^6 Drs.	
Management and Administration	101.6	2 027	5.0%	112	3 114	3.6%
	1 075.3			1 262.7		

* Excluding energy sold to heavy industries.

Comparing the unit costs in the two years, those in the later year are substantially lower in every case. Some of these reductions are quite understandable but others are less so. Taking them in turn, the steam station fuel costs are doubtless based largely on guaranteed heat rates and performances, and the only thing likely to go wrong with the estimate would be an increase in miners' wages. The other operating costs of steam generation should also be amenable to fairly precise forecasting, and with the use of much larger sets the unit costs can be expected to come down substantially. The hydro station operating costs are alos greatly reduced (less than half) but the amount is so small anyway that the forecast cannot affect the total appreciably. The diesel operating costs including fuel are estimated at an overall figure of 1 drachma per kWh, which appears reasonable.

As regards transmission operating costs the denominator chosen is the capital cost of the line and substations since the expenses are likely to be plant-related. The unit cost figure in 1966 then comes to two-thirds of that in 1962, which may seem over optimistic. In the case of distribution operating costs the denominator is the energy sales, omitting the heavy industries in 1966 since they make no use of the distribution system. For the management and administration costs the denominator is the turnover. The falls in unit costs from 13 to 11.5 and from 5.0% to 3.6% represent an expectation of some of the "economies of scale" referred to in a previous paragraph.

Whilst it is not possible to criticise any of these figures in detail it is clear that those involving a high labour content are highly vulnerable to any increase in rates of pay. Already there are indications that some of the 10-year costs will require upward revision. Following discussions with the Corporation's officers it was decided that for tariff costing purposes the operating and administration costs which had been forecast for 1966 would be increased by ten per cent.

4.4 Marginal Running Cost

A knowledge of this is necessary for two purposes, namely in allocating the cost of hydro-electric stations, and as a boundary line in the running charge of maximum demand tariffs. The following cost figures for Megalopolis strip mining were used by the Corporation in costing the output of Megalopolis steam station :

	Deutsche Marks per Metric Ton
Capital Charges	1.680
Operating Expenses	1.378
Administration	0.080
	3.138

Multiplying by a specific consumption of 3.2 kilograms per kWh sent out, and by an exchange rate of 7.5 drachmas per D.M. gives a fuel cost of 7.53 lepta per kWh. Dividing by three this is 2.51 mills/kWh. For safety, the figure was given as 9 lepta or 3 mills per kWh.

For marginal cost calculations, the capital charges and administration costs were omitted, giving a figure of : 1.378 x 3.2 x 7.5 = 3.3 lepta/kWh. With a margin of safety, this became 4 lepta/kWh. It was stated that the capital charges were based on the terms of the loans and were unaffected by the lives of the assets. It was further stated that the mine output, at present 5 million tons a year, could be stepped up to 8 million tons a year at no extra cost other than the operating expenses shown. Also that the life of the mine even at the higher rate of exploitation would still be some 35 years.

As a check on the above assumption, data was asked for regarding the nature of the capital expenditures in the mine. These were in two groups, namely mining equipment, (excavators, conveyor belts, cranes, lorries, etc.) and river diversion works. The capital costs in million D.M. were given as follows :-

	Equipment	River Diversion	Total
Immediate	100.2	19.9	120.1
Subsequent	22.6	10	32.6
Final Total	122.8	29.9	152.7

Taking the immediate investment of 120.1 million D.M. for a yearly output of 5 million tons, and assuming a total capital charge of 7% per annum, this gives the figure of 1.68 D.M. per ton as listed above.

In view of the above figures, the assumption of constant capital charges independent of output cannot be accepted as a basis for marginal costing. Even if all the shorter-lived items such as lorries are replaced out of revenue and so included in the operating expenses there must be some major items of equipment employed in strip working whose lives would be shortened if output were increased. The time when subsequent works were required would also be reduced. Furthermore, if a proportion of the capital charges is to be included with the output-related running cost the question might be raised as to whether the capital charge as a whole is as high as it should be. It would appear that the total "return" (including depreciation) on the mine investment is only 7% at a time when the corresponding return on the equity investment is 11%.

No attempt has been made to calculate a new figure, which would involve considerably more data than that given above. It would appear, however, that the correct marginal cost would lie above the figure of 4 lepta/kWh although certainly not so high as the figure of 9 lepta/kWh which has been employed for the full fuel or running cost. (Both these figures include safety margins over the calculated figures but these margins may have been intended to cover transmission costs). It seems probable that a realistic value of the marginal fuel cost, exclusive of transmission, would lie between 5 and 6 lepta/kWh.

On consideration, it was decided to use a figure of 5 lepta/kWh as the marginal fuel cost for the purpose of allocating the costs of hydro-electric stations. Where used as a boundary in tariff construction, a figure of 6 lepta/kWh will be employed. The situations are not identical, and, in the second one, transmission and distribution costs may be involved.

4.5 Electricity Sales

Fig. 1 gives a highly simplified circuit diagram of the interconnected system. Points X represent the output sides of the power stations, and A, B and C represent three sets of points at which supplies are given to consumers. Points A on the outgoing side of the main transmission line represent points of bulk supply to the aluminium and other large industries. Points B represent supplies to medium-sized high voltage industrial consumers who make use of the high tension distribution network. Points C represent the low voltage supplies.

The cost allocation is based on the assumption that all consumers make equal use of the generation and transmission system in proportion to their maximum demands at the time of system peak or potential peak period. Consumers supplied from the high tension distribution network make use also of this part of the system, whilst low voltage consumers use in addition the low tension distributors. The costs of these later sections of the distribution are shared amongst the consumers making use of them in proportion to their maximum demands at these points. Inevitably there are variations within this simple framework, and points at which the costs are intermediate, but it was felt that any further sub-division would make the cost structure too elaborate and unwieldy.

The energy consumptions and system maximum demand are those given in the 10-year forecast. Since no breakdown was given between H.T. and L.T. industrial consumers it has been assumed that their proportions will be the same as in 1962. The maximum demands of the aluminium and other new large consumers are those which have been estimated by the Corporation's staff. In estimating the load factor of H.T. industrial consumers of the present type at 70%, guidance was obtained from the study referred to in Section (3.9)

Table 13 shows the progress of supplies from power station to low voltage consumer's premises. At the intermediate points A and B, supplies are sold to consumers and the remainder passes on to the lower voltage network. Percentage losses have been assumed which seem reasonable in themselves and such that the three together add up to the total of 717 million kilowatt-hours given in the forecast.

TABLE 13

SUPPLIES AND SALES 1966
(Interconnected System)

(see page 29)

GENERATING STATIONS.

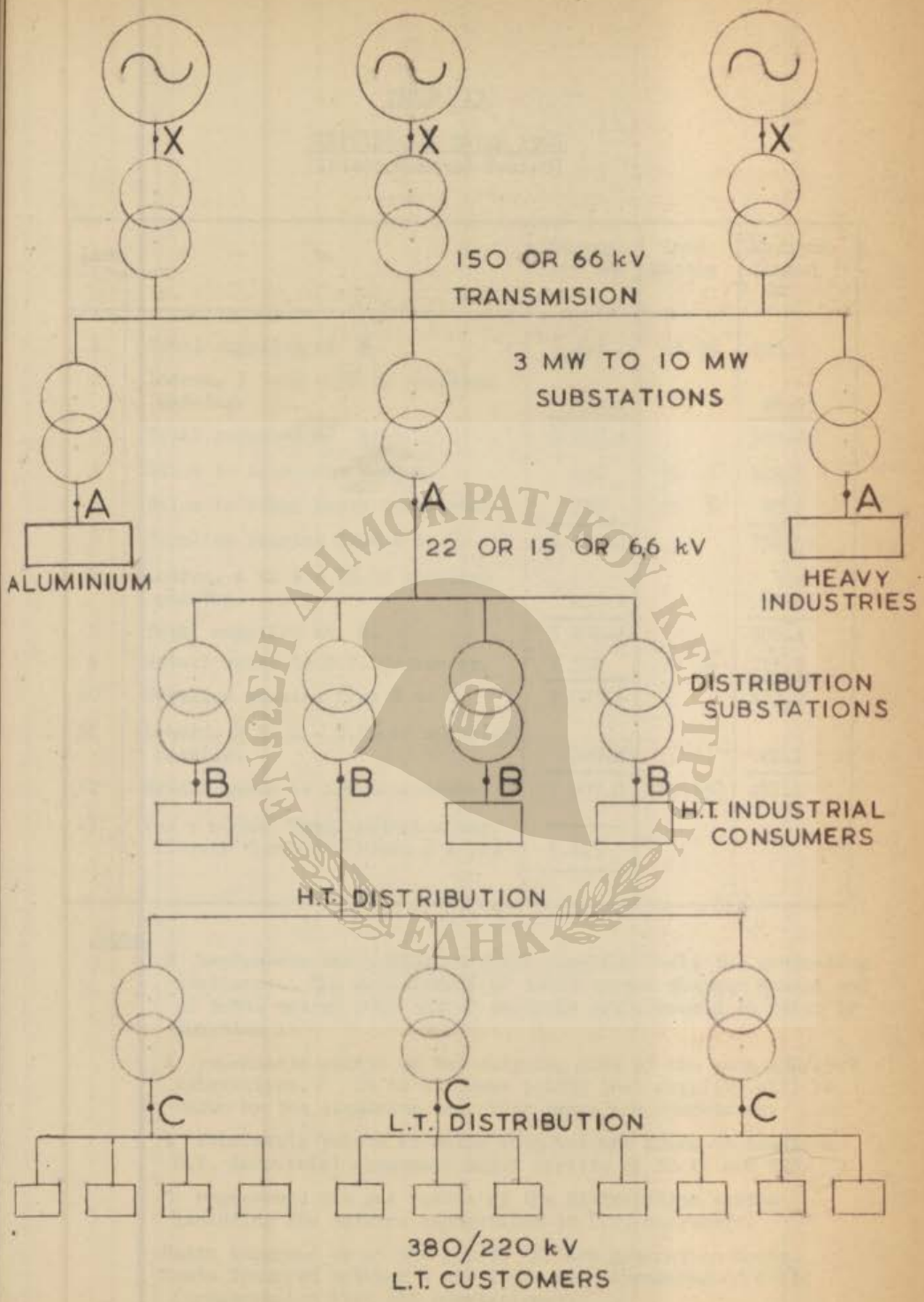


FIG.1-SYSTEM DIAGRAM.

A		B		C		D		E	
KENNEDY & DONKIN, ALLIANCE HOUSE, 12 CAXTON ST, WESTMINSTER, S.W.1.		DRAWN BY SIGN		CHECKED BY SIGN		SCALE DATE		4	

TABLE 13

SUPPLIES AND SALES 1966
(Interconnected System)

Line		Energy 10^6 kWh	Load Factor	Maximum Demand MW
1	Total supplies at X.	5 492	63.6%	985
2	Losses, X to A = 5% of supplies passing.	274.6		49.25
3	Total supplies at A.	5 217.4		935.75
4	Sales to Aluminium Company.	830	91 %	104.1
5	Sales to other heavy industries.	730	89 %	93.6
6	Supplies passing from A to B.	3 657.4		738.05
7	Losses, A to B = 7% of supplies passing.	256.0		51.65
8	Total supplies at B.	3 401.4		686.4
9	Retail sales to H.T. consumers.	1 308	70 %	213.2
10	Supplies passing from B to C.	2 093.4		473.2
11	Losses, B to C = 8.9% of supplies passing.	186.4		42.1
12	Retail sales to L.T. consumers.	1 907.0	(50.5%)	431.1
13	(as a check) Total retail sales, 10-year forecast (lines 9 & 12)	3 215		

Note

X represents the points at which supplies leave the generating stations. The measurement of total system maximum demand and of total energy sent out of stations are presumed to refer to position X.

A represents points on the outgoing side of the main 150/15kV substations. It is at these points that supplies will be taken by the aluminium and other large new industries.

B represents points at which supplies are going to existing H.T. industrial consumers under tariffs A1 to A5 and T23.

C represents the end points of the distribution system including the service connections to L.T. consumers.

Costs incurred up at the points X are generation costs.
Costs incurred between X and A are main transmission costs (transmission line and substations).
Costs incurred between A and B are described as H.T. distribution, and those between B and C are described as L.T. distribution.

4.6 Depreciation Provision

The 10-year forecast gives figures for the total cost of the fixed assets, and a breakdown was provided with certain adjustments for the 1966 total. This is shown in Column A of Table 14. As explained in Section (2.4) the figure on which a full year's capital charges are to be reckoned is the utility plant in service at the end of the year. Deductions are made for land, etc., giving the depreciable assets shown in Column C. The life periods are those given in Table 4, Section (2.3), and dividing the cost by the life gives the annual depreciation provision shown in the last column.

TABLE 14

ASSETS AND DEPRECIATION PROVISION 1966

Fixed Assets at end of year Category	A Cost 10^6 Drs.	A %	B Land & Rights	C Depreciable Assets A - B	D Life Period	E Depreciation Provision C - D
Hydro	6 142.6	33.4	450.6	5 692.6	65	87.6
Steam	3 586.2	19.5	96.4	3 489.8	25	139.6
Diesel	490.1	2.7	-	490.1	12	40.9
Transmission lines	1 188.8	6.5	56.3	1 132.5	40.	28.3
Transmission Substations.	946.2	5.1	13.7	932.5	25	37.3
Subtotal Generation and Transmission	12 353.9	67.2	616.4	11 737.5		333.7
Distribution H.T.	2 231.9	12.1	-	2 231.9	35	63.8
Distribution L.T.	3 305.9	18.0	-	3 305.9	25	132.2
Subtotal Distribution	5 537.8	30.1		5 537.8		196.0
General Utility Plant	504.9	2.7	30.2	330.0	10	33.0
Grand Total	18 396.6	100.0	646.6	17 605.3	(31.3)	562.7

Column C does not exactly equal Columns A minus B because the depreciable cost of General Utility Plant is reduced by 144.7 million drs. representing the portion of costs depreciated through operating expenses.

4.7 Revenue and Expenditure.

For costing purposes the revenue estimate in the 10-year forecast is accepted as it stands. This estimate appears to be based on the assumption that existing classes of consumers will continue to pay existing prices - i.e. that the new tariffs will have approximately the same overall money content as the old ones. The forecast assumes that the alumina revenue will be as already agreed, and that the revenue from the expected new large consumers will be in accordance with an earlier draft tariff (subsequently modified). Since neither the earlier draft nor its modification have actually been offered to prospective consumers, this portion of the revenue estimate is necessarily an open question which cannot be answered until the recommendations of this Report have been adopted or modified.

The tariff which is recommended in a later chapter appears to be higher than the formula on which the forecast revenue was based. The revenue from the large consumers (excluding alumina) should therefore exceed the estimate, and to the extent that this occurs, the "yield" indicated below should be very slightly increased. As the effect on the total is slight, and as there are so many other unknowns, it was thought better to leave the estimate untouched with the knowledge that there may be a small margin on the right side.

Table 15 shows the revenue and expenditure account for 1966. This differs from that shown in the 10-year forecast in three main respects. Firstly, the expenses are increased by 10%, secondly, the depreciation is based on the new set of life periods, and thirdly, instead of interest payments, the whole of the surplus (before charging interest) is divided by the fixed assets total shown at the bottom of Column A, Table 14. This quotient, amounting to 6.315%, is distributed over the assets in the manner described in Section (2.4).

TABLE 15

REVENUE, EXPENDITURE AND CAPITAL YIELD

Line			10^6 Drs.
1	Total electricity revenue		3 108.2
2	Other revenue		5.4
3	Total turnover		3 113.6
4	Deduct Operating costs	1 222.7	
5	General administration	40.0	
6		1 262.7	
7	Deduct additional 10% of same	126.3	
8	Sub-total	1 389.0	
9	Deduct depreciation provision (Table 14)	562.7	1 951.7
10	Total net yield		1 161.9

This yield can be spread over the capital assets in the form of a percentage, namely

$$\frac{1\ 161.9}{18\ 396.6} = 6.315\%$$

4.8 Capital Charges

The next table, numbered 16, gathers together information from the two previous tables. Column A is a repetition of Column A, Table 14. Column B shows the yield on this capital at the rate of 6.315%. Column C is a repetition of Column E, Table 14. Column D is the sume of B and C, and the final column shows the same total with the General Utility figures re-allocated pro rata amongst the remainder.

TABLE 16

CAPITAL CHARGES 1966
(Depreciation plus yield : 10^6 Drs.)

Fixed Assets at end of year. Category	A Cost	B Capital yield at 6.315 %	C Depreciation Allocation	D Total Charges etc. B + C	E Ditto with Gen.Utility re allocated
Hydro	6 142.6	388.1	87.6	475.7	494.3
Steam	3 586.2	226.4	139.6	366.0	380.3
Diesel	490.1	31.0	40.9	71.9	74.7
Transmission lines	1 188.8	75.1	28.3	103.4	107.4
Transmission substations	946.2	59.7	37.3	97.0	100.8
Subtotal G & T	12 353.9	780.3	333.7	1 114.0	1 157.5
Distribution H.T.	2 231.9	141.0	63.8	204.8	212.8
Distribution L.T.	3 305.9	208.7	132.2	340.9	354.3
Subtotal Distribution	5 537.8	349.7	196.0	545.7	567.1
General Utility	504.9	31.9	33.0	64.9	
Grand Total	18 396.6	1 161.9	562.7	1 724.6	1 724.6
As a check { Adding the operating costs (Table 15, line 8)					1 389.0
As a check { Gives the total revenue					3 113.6

4.9 Allocation

In allocating the cost of hydro generation into demand-related and energy-related a common plan is to put the costs almost entirely in the former category. This procedure arises from the fact that the hydro costs are almost entirely capital charges. The operating costs are negligible and the water is free and hence it is assumed that there are no energy-related costs. Such a procedure takes a very short-term view of the cost situation, and in a mixed hydro and thermal system such as that of Greece it could lead to faulty tariff construction. It is therefore necessary to take a broad view of the long-term costs of providing generation facilities.

A hydro scheme just as much as a thermal scheme, must be regarded as a way of purchasing both kilowatts of demand capacity and kilowatt-hours of energy output. The only difference between hydro and thermal is that in the former case both the kilowatts and the kilowatt-hours are approximately fixed for all time by the character of the site and the way in which it has been developed, whereas in a thermal station the kilowatt-hours can be varied at any time throughout the station's life merely at the cost of the fuel consumption.

If a choice had to be made between two hydro stations A and B of the same kilowatt capacity, and if B is better supplied with water and storage so that it can give a greater annual output, it is clearly worth more than A. Moreover in the present case it is possible to say just how much greater this value is. In order to make the production of A match that of B it would be necessary to generate the additional energy by other means, and the extra annual value of B is the cost of generating this additional energy.

On the basis of the foregoing argument, the annual costs of the hydro stations have been allocated as follows. The value of the energy generated has been taken as the marginal fuel cost which would have been incurred in generating the amount of additional energy at a thermal station. An appropriate rate for this has already been estimated as 5 lepta/kWh (see Section 4.4). This amount has been allocated as energy-related, and the difference between that and the total has been allocated as demand-related.

The costing of the diesel supply in the islands presents considerable difficulties. In the first place such supply is inherently more expensive, and since a common tariff system is proposed the inclusion of the outlying systems inevitably causes a fractional increase in price all round. In the second place, the extra cost appears in the accounts only in the generation sector and since the cost is largely energy-related its conclusion has the effect of artificially over-weighting the energy-related component.

The difficulty of allocation arises from the fact that the allocation system employed depends essentially on the conception of an interconnected network whose costs are sectionalised in a particular way. The problem is solved here by including the diesel costs in the totals but not in the allocation. After all the cost quotients have been computed an overall addition of 5.4% is made to each of them. This represents the actual cost of diesel operation minus the receipts from the sales in the islands assuming the same mean revenue per kilowatt-hour as with low tension sales on the mainland. The figure is some measure of the loss incurred though having to generate more dearly than on the mainland.

TABLE 17

ALLOCATION OF 1966 COSTS (10^6 Drs.)

	Operating Expenses	Ditto plus 10% plus Allocation of Administration	Capital Charges Table 16 Column E	Total "Cost"	Allocation	
					Demand Related	Energy Related
Hydro	36.8	42.9	494.3	537.2	410.2	127
Thermal fuel	361.9	421.5				421.5
Thermal other	118.0	137.4			137.4	
Thermal total	479.9	558.9	380.3	939.2	380.3	
Diesel	208.0	242.3	74.7	317.0		
Transmission	36.0	41.9	208.2	250.1	250.1	
Total G & T	760.7	886.0	1 157.5	2 043.5	1 178.0 (Excluding diesel)	548.5
Distribution H.T.	157.0	202.5	212.8	415.3	415.3	
Distribution L.T.	233.0	300.5	354.3	654.8	654.8	
Distribution Total	390	503.0	567.1	1 070.1		
Administration	112.0					
Grand Total	1 262.7	1 389.0	1 724.6	3 113.6	2 248.1 (As a check add: 317(Diesel) = 3 113.6)	548.5

4.10 Cost Formulae

The following table shows how the costs in Table 17 are divided by the electrical quantities in Table 13 to give three cost formulae.

TABLE 18

DERIVATION OF FORMULAE

Points of Supply	Demand - Related			Energy - Related		
	Costs 10^6 Drs	Demand MW	Quotient + 5.4% Drs p.a. per kW	Costs 10^6 Drs	Energy 10^6 kWh	Quotient + 5.4% Lepta per kWh
A	1 178.0	935.75	1 327	548.5	5 217.4	11.08
B	415.3	686.4	637			
	Add 7/93 of A (Losses = 7%)		160	Add 7/93 of A		0.93
			2 064			12.01
C	654.8	431.1	1 602			
	Add 8.9/91.1 of B (Losses = 8.9%)		202	Add 8.9/91.1 of B		1.17
			3 868			13.18

4.11 Revenue Check

The best check on these coefficients is to apply them to the load sequence shown in Table 13, and see if they bring in the required total revenue. This is down in the following table :

TABLE 19

REVENUE CHECK (10^6 Drs).

Selling Point	Consumer Class	MW	Rate	Revenue	10^6 kWh	Rate	Revenue	Total Revenue	Mean Price Lepta
A	Heavy Ind.	197.7	1 327	262	1 560	11.08	173	435	27.9
B	Retail H.T.	213.2	2 064	439	1 308	12.01	157	596	45.9
C	Retail L.T.	431.1	3 868	1 665	1 907	13.18	251	1 916	100.5
Total for interconnected system					4 775			2 947	61.7
Add for islands					167	x 100 assumed mean selling price		167	
					4 942			3 114	63.0*

* This is fractionally above the forecast figure of 62.3 lepta/kWh because the formulae include "other revenue".

4.12 Summary

The following table sets out the cost formulae for the three points of supply, the figures having been slightly rounded off. These formulae do not as they stand represent the tariffs to be recommended. The tariffs would usually have steps in each part, and the figures would be adjusted on account of various factors, in particular the diversity factor. Furthermore the kilowatt cost shown at C (and to a minor extent at B) is not entirely demand-related but is partly consumer-related. But these formulae do broadly define the overall revenues which the tariffs should secure at the point in question.

Point of Supply	Demand-Related Cost Drs. p.a. per kW	Energy-Related Cost Lepta per kWh
A	1 330	11.1
B	2 065	12.0
C	3 870	13.2

ΕΘΝΙΚΟ ΔΗΜΟΚΡΑΤΙΚΟ ΚΕΝΤΡΟ ΕΔΗΚ

5 TARIFF FOR LARGE - SCALE SUPPLIES

5.1 Basis of Fixed Charge

The tariff to be recommended for supplies to very large power users is of the normal two-part type with a standing charge based upon maximum demand and a running charge based upon energy consumption. A tentative tariff for this purpose was formulated in February, 1962 but was subsequently revised in an upward direction on account of increased cost estimates for Kremasta and Kastraki hydro stations and increased fuel costs in the new steam stations. The revised tariff, entitled the "New Industrial Rate-Schedule" and referred to below as NIRS, was set out on pages 7 and 8 of the "Note on the New Industrial Rate-Schedule". It is understood that whilst this rate has not actually been offered to any consumer, some of its content has appeared in print, and prospective industrialists are likely to be aware of the figures.

One feature of the NIRS was that the standing charge was based on the contracted annual maximum demand in kilowatts which the consumer might demand at any time in the year. It was intended that the consumer would agree this demand with the Corporation at the commencement of the supply, but that the actual demand would also be metered every month. If at any time during the year of account the demand reading exceeded the contracted figure the charge for the whole year would be based on the metered maximum. In practice, it is difficult to see how this would differ from the normal maximum-demand tariff coupled with a minimum charge for any year in which the revenue fell below a specified figure. Moreover, this normal type of demand charge has been employed so generally that its legal definition presents no difficulties when drafting contracts for a supply. It has therefore been adopted in the present recommendations.

Another moot point concerns whether the demand charge should be based on the separate monthly demand readings or on the highest reading in the year. Industrial consumers, particularly the smaller ones and those with low load factors, usually prefer monthly rates. Moreover, in these cases such a rate can be offered without much danger of loss of revenue since there is considerable diversity, and it is unlikely that all consumers will have low consumptions in the same month. Such monthly rates are employed in the Corporation's existing two-part industrial tariffs, and the matter will be discussed at greater length in that connection.

With large-scale supplies the position is different. Substantial capital expenditure has been incurred on account of each consumer, and a greater continuity of revenue is looked for. Since there may be only half-a-dozen of such consumers there cannot be much diversity of seasonal use to act as a revenue cushion. Moreover when annual load factors are in the 80 to 90 per cent range there cannot be very much difference between one month and another. In such a case, the annual rate might well be preferred by the consumer. If, for example, he were offered the alternative of an annual rate equal to 10½ or 11 times the monthly rate (a fairly usual ratio) he might find the annual rate to be cheaper.

It might be thought that the best solution would be to give consumers the option of a monthly or an annual rate. This, however, is not to be recommended. An option always presents a problem to the consumer and not infrequently arouses his suspicions. If he is skilful or well advised he will succeed in minimising his revenue contributions even if it means changing tariffs every few years. If he is less skilful and discovers that he has paid more than he need he will probably feel aggrieved and may even feel cheated.

The present recommendation is therefore for an annual demand charge based on the highest reading in the year. The usual procedure is for monthly meter reading and monthly billing. The demand charge would consist of a one-twelth instalment at the highest demand recorded in the year up to that point, together with an adjustment for any previous months in which the charge has been lower.

5.2 Recommended Tariff

The following is the recommended tariff for large supplies. The figures in brackets following the annual charges are the corresponding monthly instalments (1/12th of the annual). The values are derived from Formula A with a small allowance in the kilowatt charge for diversity. There are two steps (for size) in kilowatt charge, and one step (for load factor) in the energy charge.

Demand Charge

First	5 MW :	1400 Drachmas per annum per kW	(116⅔ Drs. per month)
Next	15 MW :	1200 " " " " "	(100 " " ")
All over	20 MW :	1100 " " " " "	(91⅔ " " ")

Energy Charge

12 Lepta per kWh for the first 400 kWh per month per kW of M.D.
8 " " " " all additional consumption.

Alternative Demand Charge

In spite of the recommendation made above regarding annual demand assessment, it may be thought desirable to employ monthly assessments. This could arise on policy grounds, e.g. if consumers greatly preferred it, or in order to be the same as on the smaller tariffs. In this case, the following are the recommended figures, approximately one-eleventh of the annual ones. This alternative is presented for the Corporation's decision before finalising the tariff, and not as an alternative to be offered to the consumer.

First	5 MW :	125 Drachmas per month per kW
Next	15 MW :	110 " " " " "
All over	20 MW :	100 " " " " "

5.2.1. Size Coverage

The tariff is designed for consumers of 1 MW and upwards taking supplies from the main transmission system as indicated at A in the system diagram. Whilst there is no upper limit to the cost calculation on which the figures have been based it is a policy question as to whether a limit of, say 20 or 30 MW be placed on the tariff as published. Very big supplies involving major changes in transmission, and possibly even affecting the generation programme, will necessarily involve special negotiations. By not committing itself on the larger sizes in the published schedule the Corporation gives itself a certain amount of elbow room for negotiation.

5.2.2. Cost Coverage

The tariff covers the cost of a substation of the same type and equipment as those included in the Corporation's main transmission system. It also includes the cost of the necessary metering. It does not include the cost of service connection or of any part of the transmission system which is provided solely for this consumer's use. Nor does it include the cost of any special protection equipment or duplication of supply beyond that provided in the normal transmission system.

5.2.3. Minimum Charge

Assuming that the demand assessment is on an annual basis this provides a certain amount of guarantee against revenue loss in months of low consumption. Apart from this there should be a minimum annual or monthly charge whish is at least sufficient to cover the capital and operating costs on all the equipment reserved for that consumer's exclusive use.

5.2.4. Connection Charge

When connection costs are incurred beyond a proportional share of the common transmission system as detailed in (5.2.2.) above, the consumer might be asked to pay in addition to the standard rate, one or other of the following :

(a) A once-for-all connection fee.
(b) An annual fixed charge for the special equipment provided.
(c) An increased minimum charge as described at (5.2.3.) above.

5.2.5. Fuel-Cost Variation

It is proposed that the energy charge be subject to a variation according to the cost of fuel consumed in the Corporation's thermal stations.

5.2.6. Power Factor Variation

In the event of the monthly power factor of any consumer falling below 0.85 a power factor penalty should be imposed. This could either be of the form proposed in the NIRS or it could take the form of an increase in the assessment of monthly maximum demand in the ratio $0.85/\cos \varphi$.

5.3 Comparison with Previous Proposals

The following Table 20 compares the results of the recommended tariff with those of the NIRS. The table compares the overall price per kilowatt-hour under these two rates at four different load factors. The comparison is made for two consumer sizes, namely those in the range 1 to 5 MW and those of 20 MW.

TABLE 20

COMPARISON OF RESULTS
(All figures in Lepta per kWh)

Load Factor -		40%	60%	80%	100%
Up to 5 MW	Tariff	52.0	38.3	30.7	26.2
	NIRS	59.3	42.6	34.0	28.1
	Difference	7.3	4.3	3.3	1.9
At 20 MW	Tariff	47.7	35.4	28.5	24.5
	NIRS	49.1	35.8	28.9	24.0
	Difference	1.4	0.4	0.4	-0.5

It will be seen that at 20 MW the recommended tariff gives almost identical results to the NIRS on all load factors from 60% upwards. At 40% load factor the tariff is about 3% lower. On sizes up to 5 MW the tariff is a little lower than the NIRS at 100% load factor and appreciably lower at low load factors. Over the whole of this field, both as regards size and load factor, the tariff is fractionally lower than the NIRS but the differences are inconsiderable.

On sizes above 20 MW the tariff begins to come higher than the NIRS, particularly on high load factors. This is because the NIRS has a very steeply falling series of price reductions in the kilowatt charge. Even so, the differences are not great until really large sizes are reached such as 40 MW, combined with high load factors.

It follows from the above that even if the terms of the NIRS had been widely publicised, it is hardly possible that any plans made by industrialists on this understanding could be seriously affected by the new proposals. On the smaller size ranges the new tariff will be fractionally cheaper, and only on the very large sizes will it be appreciably dearer. Furthermore, since the NIRS employed a somewhat different basis of demand assessment which has not been precisely defined this would make it even more difficult for unfavourable comparisons to be made between the tariff and the NIRS.

5.4 Comparison for Prospective Large Consumers

Estimates have been prepared for four very larg consumers likely to be requiring supplies. Three out of the four have load factors around 80 to 85%. The overall prices under the tariff and the NIRS are shown in Table 21.

TABLE 21

COMPARISON FOR PROSPECTIVE LARGE CONSUMERS

Consumer	MW	GWh	Load Factor	Overall Price: Lepta/kWh			Per Cent Difference
				Tariff	NIRS	Difference	
Phosphorus	15	70	53.3%	39.1	40.9	- 1.8	- 4.4%
Larymna	25	170	77.6%	28.8	27.4	1.4	5.1%
Steel Plant	30	220	83.7%	27.0	24.6	2.4	9.8%
Nitrogen	35	270	88.0%	25.8	22.1	3.7	16.7%

5.5 General Comparison : Reductions for Load Factor

It will be seen that the NIRS differs from the proposed tariff in two ways, namely in giving substantial price reductions on very high load factors, and in giving even greater price reductions on very large sizes. Both of these are desirable objectives - that is to say, it is advantageous to have a high load factor, and it is doubtless desirable to attract very large loads so as to make a rapid contribution to the country's economy. But as with other objectives there are financial limits, and, if pushed beyond this point, an uneconomic development would be encouraged.

As regards load factor, the two-part maximum demand tariff was invented for the express purpose of improving the load factor, and if the two parts are correctly proportioned this improvement will be encouraged to the exact extent that it is economically desirable. The device of an additional step, dependent on load factor, in the energy charge was introduced because of the "tilting" of the two parts away from their correct economic proportions. In the case of the NIRS the effect of the last step at 4 lepta/kWh is barely noticeable because it operates on so small a number of kilowatt-hours, but it is wrong in principle. Reasons have been given in Section (4.4) for regarding 6 lepta/kWh as one of the tariff parameters or boundaries below which no element in the consumption should be priced. The present recommendation is well above this irreducible minimum.

Taking a broad long-term view, it was explained in Sections (3.4) and (3.5) that since the load factor of the Greek load is higher than the economic load factors of the hydro resources the steam stations have to be operated at still higher load factors in order to make up the balance of energy requirements. This can usually be done at the bare cost of the extra fuel, and the marginal running cost calculations of Section (4.4) have been based on this assumption.

There is an obvious limit to this, since load factors cannot exceed 100%, and in fact the annual plant factor of a steam station must be appreciably lower than this owing to the necessity for periodic overhauls of boilers and sets. Owing to the acquisition of high load-factor loads such as the aluminium works the system load factor is expected to rise, and as a consequence the steam station plant factor is scheduled to reach nearly 80% in 1972 (Table 8). Further load factor improvement might well increase this to the maximum availability percentage of which the plant is capable. Additional energy would then require additional plant and not merely additional fuel. Whilst such capacity limit is not yet in sight it might become a future risk if the tariff offers excessive price reductions for high load factors.

5.6 Reductions for Size : Consumer Costs

The position as regards the price reductions for large sizes is somewhat different. The reasons for this are only partly economic; to a much greater extent they are reasons of commerce or policy. The economic reasons arise from what is called "consumer costs", that is to say, costs which are independent of the consumption in kWh or the demand in kW but are related to the number of consumers and can be expressed per capita. Thus the cost of the meter and the metering, the billing and the accounting are almost independent of the size of the account. In the cost of the service connection, the substation, the transformer, switchgear, etc supplying the consumer there is a "constant" element unrelated to the maximum demand since a 10 MVA transformer does not cost twice as much as a 5 MVA transformer.

In short, the annual cost of supplying a 10 MW consumer is less than the cost of supplying two 5 MW consumers, and it is usual to charge him less. Under the recommended tariff, the revenue derived from two 5 MW consumers will be one million drachmas more than the revenue from one 10 MW consumer having the same total demand and consumption, and it is easy to see that this is much greater, than any "consumer cost" that is likely to arise.

To begin with, the consumer cost can only arise in the transmission system, since there can be no difference in generation cost between the 10 MW and the two 5 MW supplies. If anything, the difference would be the other way round, since there is some slight possibility of diversity between the two 5 MW consumers which could not arise with one consumer. In the second place, the difference would arise not in the transmission line itself but in the subsequent substations, etc. Now the whole of the main transmission system costs equal 267 drachmas per annum per kilowatt of system demand, of which the substations account for only one-third. Hence the substation cost for a 5 MW supply is about 267/3 x 5000 = 460 000 drachmas per annum.

It follows from the above that the contribution which a 5 MW consumer is making towards the consumer costs, namely half-a-million drachmas is sufficient to pay for the whole of his substation costs, and is many times greater than the difference in the unit cost of supplying smaller and larger consumers. Moreover, this calculation has concerned only one of the price reductions, that occurring above 5 MW. There is a further small step of reduction occurring above 20 MW.

5.7 Reductions for Size : Non-Economic Factors

It is obvious that the major argument for additional price reduction with size increase is not an economic one since even with the reductions already proposed the smaller consumers will be more remunerative to the Corporation. The main arguments are commercial and political. The commercial argument is that the larger consumer is in a better competitive position than the smaller one, and so must be offered a lower price. The strength of his position is that he has alternatives: he can either (a) generate for himself, or (b) go elsewhere. If his industry is one in which power costs are a high percentage of the value of the product he will usually have no difficulty in producing figures to prove that only below a certain (low) figure per kWh is his production possible.

This is a situation which can only be dealt with as it arises, and in an ad hoc manner, it is not one on which a precise recommendation can be made. It should, however, be pointed out that such a procedure constitutes an exceedingly dangerous basis for tariff construction. Each "special case" is apt to form the precedent for a still more special case, and in general an electric utility is well advised to stand pat on its own economics of supply and not to venture into the economic fields of its consumers. As regards the fear of losing potential sales through being "priced out of the market" it is noteworthy that in the U.K. where the public suppliers have had to meet keen competition from very well informed private industrialists the final step of the kilowatt charge is seldom less than 80% of the price of the first step, and averages about 90%. In the NIRS the last step price is only 12% of the first step price.

A nationalised utility, such as the Corporation, has a special responsibility in this matter to hold the scales as equitably as possible as between its different consumers and to assist in a balanced national economy. In the case of a privately owned utility the management could always decide, if they wished, to be generous to one class of consumer, since, if necessary, the money could come out of the shareholders' pockets. But in the present case, any revenue remitted to one class of consumer must be recovered from the remainder.

The other policy issue on which no general recommendation is possible is that in which certain industries are preferred to others in the national interest, e.g. in relation to exports or to their high employment content. The only connection this has with the foregoing paragraphs is where such industries tend in their nature to be large rather than small. Except for specific cases, there is no obvious reason for any such connection, and therefore no prima facie reason to regard one 20 MW consumer as more desirable than four 5 MW consumers. A complete judgment on such an issue would involve very many non-electrical elements, and the utmost that the tariff recommendation attempts is to give a purely electro-economic measure of the desirability of size.

There is one aspect of this question which is special to the Greek situation. In a very large interconnected system such as those in the U.K. and Continental mainland it is hardly likely that any single new consumer, however large, would seriously embarrass the

power supply situation or necessitate a change in the generation programme. But in Greece, one or two new loads in the 30 to 90 MW size range (which is the size which the NIRS may be said to be specifically aiming to attract*) could seriously affect the programme.

The Corporation's generation construction programme is extremely large in proportion to the size of its system, and about half of it consists of hydro schemes which necessarily involve a greater margin of uncertainty than thermal schemes. At this juncture, the policy of a tariff designed to give special encouragement to very high loads may therefore be questioned.

Before departing from the tariff in obedience to other, non economic, considerations the following two points should be borne in mind. In the first place, since the tariff has a factual cost basis it offers an objective point or anchorage at which to rest. Once this is departed from there is no other particular stopping point, and it is more difficult to resist the various pressures that may be brought to bear on the whole tariff structure.

In the second place, the proposed tariff is based on a consistent plan for the whole system under which the costs are shared according to the point in the system at which the supplies are given. A departure in one sector therefore affects the remainder, and if one portion of the consumption pays less than its allocated share then either some other consumer group must pay more or else the overall target will not be reached.

* Under the NIRS, as the size increases from 30 to 90 MW the kilowatt charge falls to less than half.

6 TARIFF FOR MEDIUM-SCALE SUPPLIES

6.1 Field of Application

The next step is to make suggestions for a tariff appropriate to the medium-sized industrial consumers now being supplied at 6.6 kV and 22 kV. These are chiefly in the 50 to 1000 kW size range, and the following table (22) giving the statistics for 1962 will show the total field to be covered.

TABLE 22

HIGH TENSION INDUSTRIAL CONSUMERS, 1962

Area		Capital	Provincial	Total
Tariffs		A1 to A5	T23	
Number of Consumers		516	87	603
Consumption	10^6 kWh	633.8	216.4	850.3
Revenue	10^6 Drachmas	355.8	108.5	464.3
Mean revenue per kWh	Lepta	56.1	50.1	54.6
Mean revenue per consumer	10^3 Drachmas	689	1247	770
Mean consumption per consumer	10^6 kWh	1.23	2.49	1.41

It will be noted that whilst only about 15% of the H.T. industrial consumers are in the Provincial area the average size of these consumers is about twice that in the Capital area. As regards the most important element in the comparison, namely the price, the figures are inconclusive. It is true that the mean price in the Capital area is about 11% higher, but with tariffs such as these which have price reductions for size the higher price could easily be accounted for by the smaller mean size. Above all, since the price varies strongly with the load factor it is impossible to compare prices without a knowledge of this. All that can be said is that there is no evidence to show that tariff T23 is either higher or lower than tariffs A1 to A5.

6.2 Points of Supply : Cost and Revenue

It is presumed that the consumers in question are being supplied from points B in the system diagram - i.e. they make use of the transmission system and of the H.T. distribution system but not of the L.T. network. Their costs of supply will therefore be expressed by cost formula B (Section 4.12). There will, doubtless, be cost differences between different consumers within this classification but these should not be sufficient to upset the averaging procedure, except that it may be necessary to give a small percentage rebate for supplies given at 22 kV.

If the load factor assumptions on which Table 13 was compiled are correct, the mean cost of supplying this group of consumers is 45.9 lepta per kWh (Table 19). This is 16% below the present mean revenue shown above, and even if the group load factor should prove somewhat lower than the estimate there would still be a slight margin in hand.

The broad conclusion is that the new tariff will only have to secure about the same mean revenue as or somewhat less than the present tariffs are bringing in. This does not mean that no consumer will have to pay more than before, but it does suggest that the problem of transition without hardship, although difficult, is not insoluble. It gives rise to the hope (provided the variations within the present tariffs are not too extreme) that it will be possible to construct a tariff on the basis of formula B which will replace the present schedule without severe hardship to anyone, and with (on balance) as many price decreases as price increases.

6.3 Possibility of Unification

Apart from the question of overall revenue dealt with above, the chief difficulty arises from the multiplicity and complexity of the existing rates. Counting the two areas this one class of consumer is catered for by six published tariffs and a number of special rates. Each tariff has several steps in each of its parts, and there are additions for fuel cost and remissions for peak avoidance.

It would seem a rash assertion to suggest that the whole of this can be swept away, and that a single two-part tariff with, perhaps, two price steps in each part can deal adequately with the whole field. Moreover, it is an assertion which cannot be substantiated without more investigation than has yet been possible. Nevertheless it is the view taken in the present Report, and is supported by experience in a number of places where similar "tariff jungles" have been successfully brought into orderly cultivation.

6.4 Proportion of Parts

One further difficulty in the transition arises from a feature which is common to all the present H.T. industrial tariffs (A1 to A5 and T23) namely, the very low ratio between the demand charge and the energy charge. In fact, the contrast between them and the NIRS which was proposed for the very large consumers is so great that it is difficult to believe that they refer to the same utility. Comparing the largest of the present tariffs, A5 (which at present serves two consumers of over 10 MW) with the NIRS intended for consumers above the A5 range, the demand charge in A5 is less than half that in NIRS, yet the energy charge is six times as great. (The figures refer to the first step of the charge in each case). Comparing the numerical ratio between the demand charge and the energy charge, this ratio is fourteen times as great in the NIRS as it is in A5.

Apart from the technical objection (which some would regard as merely academic) that these two widely different proportions cannot both represent the costs, there is the strictly practical objection that if they are to operate (as they must) over contiguous areas of the size range they cannot merge smoothly but will produce very serious anomolies and inconsistencies.

It may be said at once that, as regards cost representation, it is the NIRS which is the more correct, and any recommendation that can be made for the existing consumer groups will necessarily have a much higher ratio of demand to energy charge than have the present tariffs. It follows that even if the new tariff secures the same overall revenue as the old ones it will bear more hardly than at present on the low load factor consumers and less hardly on the high load factor ones.

6.5 Necessity for Revenue Trials

When making a substantial tariff change, particularly where it means a change of type or structure, or a substantial change in proportions, it is not possible to produce an "ideal" or "correct" tariff in a single operation or by a series of calculations. It is necessary to make a number of essays and revenue trials in order to determine the most appropriate values. As regards revenue, such trials are necessary for two reasons, namely to see that the proposed values will bring in the required total revenue, and to examine the incidence on the individual consumer. As regards the latter point, it is obvious that a new tariff might secure no more total revenue than the old one and yet might make individual changes which are so severe as to produce serious hardship.

As regards total revenue, the first step is to get statistics for each of the existing tariffs and, by treating the group as though it were a single "average" consumer, to apply the new tariff proposals to this hypothetical individual. In the case of the H.T. tariff proposed below, this step has been taken and the results are tabulated subsequently. This procedure cannot give very reliable results but is useful in the first stage. It tends to overstate the tariff yield for statistical reasons of which the following is an example. The "average" consumer may have a load factor such that his whole consumption lies within the first step in the running charge and therefore all incurs the maximum kilowatt-hour charge. But the total consumer population of which he is supposed to be the representative average will include some higher load factor consumers, and some of the consumption will therefore be at the lower kWh rate.

If this first trial indicates that the proposed values are likely to be satisfactory on total revenue, the next step is to apply the figures to individual consumers' accounts. This will give a further check on total revenue and will be a guide to the individual incidence. Since the same process may have to be carried out on several different sets of values it is important to devise a procedure which will need as little time and staff as possible. For this reason, sampling methods should be used wherever the consumer groups are large. This applies to some of the H.T. tariffs and to almost all of the L.T. ones both industrial and non-industrial.

For reasons of time, this second stage has not been carried out in this Interim Report for any of the existing consumer groups. What has been done is to make a tentative tariff proposal for the H.T. industrial consumers and to examine its overall effects. Recommendations are also made regarding the next stage in the work in this field. Similar suggestions are made in connection with the L.T. supplies - industrial, residential and commercial.

6.6 Tentative Tariff Proposals

It is recommended that a single tariff shall take the place of the present tariffs A1 to A5 and T23 for industrial consumers taking a H.T. supply and having contracted capacities in the range, say, 100 kW to 10 000 kW. It is further recommended that the demand assessment be on a monthly basis, as at present. This is usually preferred by the consumers, particularly the smaller and lower load factor ones, and (judging from such study as has been possible of the seasonal fluctuations of demand) it does not appear to involve appreciable risks to the Corporation. In working from the annual demand-related costs a denominator of $10\frac{1}{2}$ has been taken for the corresponding monthly charge. (In the case of the large-scale tariff a figure of 11 was used).

In arriving at the tentative tariff values set out below, the starting point was the cost formula B. An allowance was made in the demand charge for average diversity, and in addition there has been some "tilting" of the two values to allow for what is called "differential diversity". This phenomenon means that there is a greater likelihood of individual diversity the lower the value of the individual's load factor, and the method of compensation is to increase the running charge and decrease the demand charge in such a way that the overall revenue (on the average load factor) is unaltered. In addition to these economic reasons the tilting is desirable in the present case in order to lessen the shock of transition.

The demand charge has a size step in order to recover the consumer costs, and this is coupled with a minimum monthly charge as in the present tariffs. The running charge has a load-factor step which ensures that industrialists who operate multiple shifts and so achieve higher load factors having good diversities with the single-shift operators are not penalised by the tariff "tilting".

Demand Charge

First	100 kW :	140 Drachmas	per month per kW (Minimum 20 kW)
All over	100 kW :	"	" " " "

Energy Charge

25 lepta per kWh for the first 400 kWh per month per kW of M.D.

20 " " " " all additional consumption.

The energy charge will be subject to a fuel-cost adjustment, and the above figures are intended to include the amount of the adjustment as at the time when the tariff is introduced.

There are a number of other possible adjustments on which decisions must be made before the tariff is finalised. These include power factor penalties, discounts for prompt payment of accounts, reduction for extra high tension supply, and remission of demand charges for voluntary limitation of demand during peak hours. Discussion of these points is deferred until the broad outlines of the tariff have been settled.

6.7 Revenue Trials on Present Tariff Groups

The tentative tariff proposals made above were tried out (together with certain alternative values) on the six existing tariff groups. By treating each group as a single "average" consumer, the revenues under the new proposals were compared with the present revenues using the 1962 consumptions and demands. The results are given in the following table (23).

TABLE 23

COMPARISON OF REVENUES

Tariff	A1	A2	A3	A4	A5	T23	Total
Number of Consumers	197	217	88	9	5	87	603
Consumption per Consumer 10^3 kWh	272	570	2184	15280	25330	2488	1410
Mean monthly M.D. 10^3 kW	82	156	437	2240	4814	526	296
Mean revenue per consumer 10^3 Drs	202	370	1232	7494	11956	1247	770
Mean revenue per kWh Lepta	74.4	64.9	56.3	49.0	47.2	50.1	54.6
Ditto, Tariff Proposal	79.2	68.3	51.6	41.5	47.5	52.8	54.4
Increase or Decrease	+4.8	+3.4	-4.7	-7.5	+0.3	+2.7	-0.2
Ditto per cent	+6.5	+5.2	-8.3	-15.3	+0.6	+5.4	-0.4
Minimum sampling ratio	1 in 5	1 in 5	1 in 3	All	All	1 in 3	
Sample size	39	43	29	9	5	29	154

The following are the conclusions which can be drawr from this table. The overall revenue from the tentative tariff proposal is almost identical with the present revenue. In the event, it might prove somewhat lower owing to the statistical factor already mentioned, but this is in line with the estimated costs and is provided for in the 1966 overall estimates. As regards the separate tariff groups, the new proposal shows an increase in the mean price (but nowhere more than 6½%) in the groups now served by tariffs A1, A2 and T23. It shows a reduction to groups A3 and A4, particularly the last-named whose average load factors, for some reason, are the highest of them all. In short, from the revenue aspects the results of the proposal can be regarded as satisfactory both in total and in each group.

6.8 Incidence Trials

From the above showing it might appear that the tentative tariff proposal could replace the whole of the existing H.T. industrial tariffs without any hardship whatever, in fact almost without anyone noticing, since in no group is the increase more than a small percentage. (Possibly less even than that shown, owing to the over-statement element). This apparent smoothness of transition however refers only to the totals and not to the individuals. Owing to the change in proportions - i.e. the larger demand charge and smaller running charge - the low load-factor consumers will have their prices increased, and vice versa.

The only way of finding the extent of this, and also of checking the total, is to examine the accounts of individual consumers and to see what they would be under the new proposals. It is therefore recommended that a trial be made using sampling methods. A random sample should be made by picking out uniformly and without discrimination one out of every five (say) of the consumers under tariff A1. This will give a sample of 39 which should be fairly representative of the whole group. The same thing should be done for each of the other tariff groups, and the last two lines of Table 23 give the suggested proportions and sample sizes for each group. In the small groups A4 and A5 the whole of the consumers will of course be examined.

The above-mentioned proportions will yield a total of 154 accounts to be examined. This keeps the operation within bounds and enables several alternative values to be tried out if necessary without excessive labour. Naturally, larger samples would give more reliable results, and when the proposed tariff values have been almost finalised it might be worth while to make a check with larger samples, specially in any likely danger area. (i.e. any group likely to be badly hit).

The results should be tabulated showing the increase or decrease to each consumer per cent and in total revenue. Any quantity in the sample that can be compared with the total, such as mean consumption per consumer, mean size, mean demand, etc. should be worked out, since this is a check on how far the sample is representative.

7 TARIFFS FOR LOW-VOLTAGE SUPPLIES

7.1 Field to be Covered

The third and last sector of consumption to be examined is that which includes all the consumer groups supplied from the low-voltage network (as represented by points C in the system diagram). The costs of supply have already been worked out and expressed in Formula C but the formula is less easy to apply than in the case of A and B for a number of reasons. The loads supplied are of a much more varied character, the pattern of tariff usually employed does not follow the cost pattern nearly so closely as with A and B, and the cost formula itself has to be modified so as to cover the element of consumer cost. The following table (24) contains rearranged data from Table 6, Section (3.1) with some additional information.

TABLE 24

LOW TENSION SUPPLIES 1962

Consumer Class	Percentage of Sales	Percentage of Revenue	No. of Consumers	No. of Consumers %	Mean Revenue - Lepta/kWh	Mean Revenue - Drs/Consumer
Residential	35.7	49.4	1 060 657	82.9	127	980
Commercial	9.0	11.6	163 184	12.8	118	1 500
Industrial L.T.	11.6	11.7	38 954	3.0	92	6 300
Miscellaneous	4.9	4.1	16 518	1.3	77	5 240
Total	61.2	76.9	1 279 313	100.0	115	1 260

It will be seen that these low tension supplies comprise over 60% of the total, and contribute more than three-quarters of the revenue, but these proportions will be smaller in 1966 and subsequent years. As regards overall revenue, the mean price of 115 lepta per kWh shown above can be compared with the figure of 100.5 lepta at the point C in Table 19. (Actually the revenue requirements at B and C will be somewhat above those shown in Table 19 because the revenue at A will be less on account of the Aluminium Contract).

This suggests that broadly speaking no substantial price increases will be necessary, but this comparison is not so simple and clear-cut as it appears. There is a great variety of uses and of tariff structure, the problem of tariff unification will be more complex, and a mere comparison of overall prices before and after is very little guide.

7.2 Residential Tariff : Fundamental Principles

Much the largest of the four groups listed above is that of the residential or domestic consumer. In addition to its size, two other factors combine to make the residential sector particularly important and particularly difficult. The importance arises from the fact that 83% of the consumers are in this class. Over a million persons are involved and they form the chief point of contact between the Corporation and the general public. The difficulty arises from the fact that different types of tariff are employed in the two areas (Provincial and Capital). One or other will have to go, and the question is - which? In order to present the choice clearly, it is necessary to say something on the general principles of domestic electricity pricing.

Electricity consumption in the home tends to be in two layers or slices. There is a basic or fundamental layer for such essential purposes as lighting, radio and minor electrical services which virtually every consumer will need. There is a supplementary layer for optional purposes such as cooking, water heating, refrigeration and air conditioning which comparatively few consumers will use, yet which probably makes up the greater part of the domestic consumption.

The characteristics of the first slice (to the user) are that it has a high "use value" in the sense that one kilowatt-hour will give several hours' service of a far better quality than can be obtained from any other source. There is no effective competition, and the consumption is therefore very little affected by the price. The characteristics of this slice to the supplier are that since it is chiefly for one single purpose - lighting - occurring only over a few hours a day (and the same hours throughout the country) it has very little diversity and so is expensive to supply. In addition, the "consumer costs" or per capita costs must be recovered in this slice or else some consumers will evade paying them.

The characteristics of the second slice or "follow-on" consumption are just the reverse. The services it renders have attractive alternative sources (except possibly in refrigeration where the electricity load is small and its cost is only a minor element). If the electricity price is high in this slice the load will not develop as it should, and as it (economically) could.

From the supplier's aspect, this slice is relatively cheap to supply because the uses are so varied that there is a large diversity. The uses extend over very many hours of the day, and there are possibilities of night storage. Even where there are seasonal fluctuations these may be complementary, as in the case of space heating and air conditioning.

Tariff policy in the residential field has therefore always been aimed at making a relatively high charge for the first or basic slice of the consumption - that is to say, broadly, for lighting, and a much lower charge for all the additional consumption. Tariffs have differed chiefly in the means adopted for distinguishing between the two kinds of consumption. The earliest plan, which still has a limited field of useful application, is to employ separate wiring and metering and to make a separate (relatively high) flat-rate charge per kilowatt-hour for lighting. Experience has shown, however, that this does not promote the fullest development of the domestic load, and one or other of the two under-mentioned plans is usually followed.

One plan is to employ a block tariff of two (or sometimes three or four) blocks or slices of consumption at successively lower prices per kWh. This has been the practice in the Provincial area (Tariff No. 9). The other plan is to have a two-part tariff consisting of a fixed annual or monthly charge based on the size of the residence, and a relatively low running charge per kWh. This has been the plan in the Capital area (Tariff T.3) in respect of about two-thirds of the residential consumption.

There are variants of these two plans: for example, a two-part tariff having the same fixed charge for all consumers independent of house size will give results comparable with those of a block tariff. A contrary plan, called the variable-block tariff employs a first block of a size varying with the size of the premises, and this gives results like those of the two-part tariff. It is best to group these two variants with the tariffs giving similar results rather than with the tariffs having similar names. The pros and cons of the two are then as follows.

7.3 Choice of Type of Residential Tariff

It will be clear from what has been said above that the two-part tariff is technically superior to the plain block tariff. The aim is to charge more heavily for the lighting component of the consumption, and the amount of this component, that is, the point at which basic essential consumption ends and "luxury" consumption starts must depend very largely on the size of the house. With the block tariff, on the other hand, the point of price change is the same for all consumers. Those in a large house may be buying much of their lighting energy at the cheap rate whilst those in a very small house may never reach the point at which the cheaper supplies commence and so will have no encouragement to make use of the more varied electrical services. Experience in many countries has shown that a two-part tariff or its equivalent, the variable-block, has proved the quickest way of developing the residential load on terms attractive to both consumer and supplier.

The disadvantage is the greater complication of the two-part tariff. It requires a greater number and more highly skilled staff to administer it since there has to be some sort of assessment of the individual premises. Whereas in the block tariff the electricity bill depends upon one thing only, the reading of an energy meter about which there is rarely room for much dispute, in the two-part tariff a second quantity is involved. Moreover, electricity suppliers themselves are not agreed as to what attribute of a residence forms the best basis for the fixed charge. In Tariff T.3 of the Capital area the basis used is the floor area, and this is probably the most widely used basis. Elsewhere, the number of habitable rooms has been used, and several other bases have been tried.

Since the Corporation employs both types of tariff in its two areas it will be well aware of their pros and cons in the circumstances of Greece's electricity supply. It is therefore recommended, before any tariff magnitudes are discussed, that very serious consideration be given to the choice of type. Some estimate should be made of the feasibility of operating throughout Provincial Greece a tariff of the T.3 type, and of the staff and time needed to put it

into operation. Also of the loss or technical disadvantage of the alternative, namely substituting a block tariff in place of T.3 in the Capital area. There would be little point at this stage in examining the effects on individual consumers since this must depend on the values employed. But a prior consideration of types, with particular reference to the organisational side, would save valuable time when the final section of the work comes to be done.

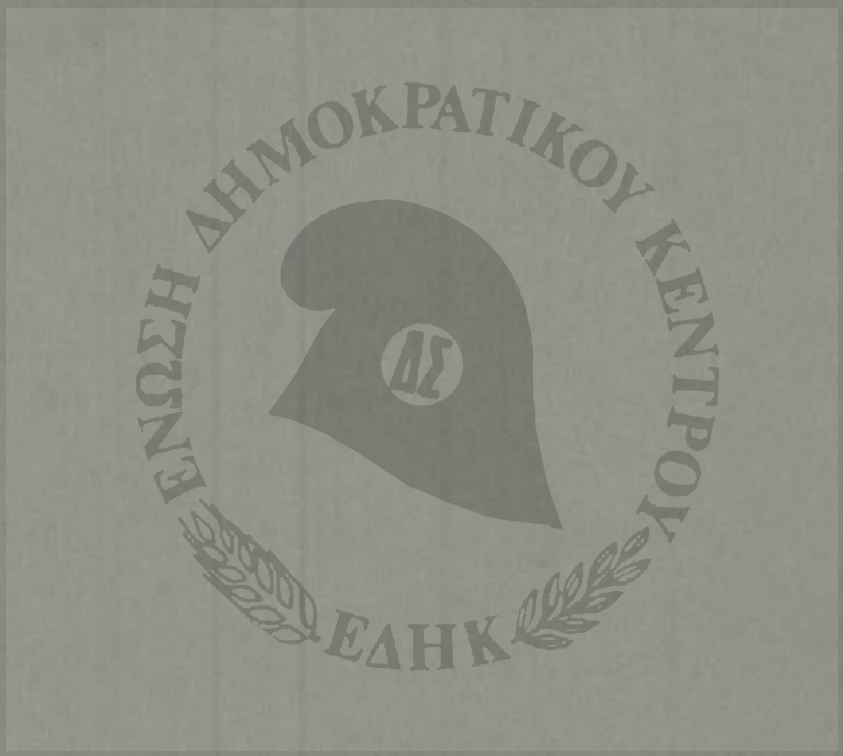
7.4 Programme for Other Low-Voltage Supplies

No recommendations are made regarding other supplies and no attempt has been made to deal with them in the Interim Report. It may be well, however, to indicate the broad lines to be followed. The first step is to group the consumers into the existing tariff classes and to see whether a single tariff type can be made acceptable for both areas. The next step is to estimate load and diversity factors and, by using the cost formula, to see what tariff values are required if the revenue from the consumer group is to be in accordance with the cost of supply. Within this cost envelope the particular values and steps are then chosen so as to minimise the changes to the consumers.

When values have been selected, these can be tried out both on the average consumptions of the groups and on the individual accounts. In the latter operation, sampling methods can be used where the consumer numbers are large. Where there are special tariffs for particular uses, or in one area only (e.g. irrigation) these should be made generally available. A unified procedure must also be devised in respect of fuel cost variations and discounts for prompt payment of accounts.

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DJB/MRM
31st July, 1963


ΕΝΩΣΗ ΔΗΜΟΚΡΑΤΙΚΟΥ ΚΕΝΤΡΟΥ
ΕΔΗΚ