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HOURLY COST OF ELECTRICITY SUPPLY IN AN INTERCONNECTED SYSTEM

by

Efraín Friedman and Raúl Schkolnik

Note: This text is subject to editorial revision.

1. Introduction

The application of logico-mathematical methods to the study of interconnected systems using hydraulic and thermal energy resources may be very useful, and lead to substantial savings in investment and operation as well as to a better rates policy. Their practical use, however, is highly dependent on the stringent and systematic formulation of method, so as to enable the calculations, which are both tiresome and very long, to be done by high speed digital computers.

ENDESA is now taking the first steps towards this objective and possible methods are being tried out for the study of: (1) the way in which a system of installations operates for supplying a given consumption, under specific hydrological conditions; (2) the way in which the total annual cost of a system should be distributed among the different hours in a year, due consideration being given to the variability of the daily seasonal consumption curve.

The first kind of study can be helpful in determining the best type of plant to build; the uses of different hydroelectric or thermoelectric alternatives varying in generating power capacity and work regime; the best way to develop a site for the power station with different capacities and that may be built in various stages; the energy that may be offered over the short term as a low-cost surplus; in short, a large number of problems connected with the programming of a system on more economic lines.

The second kind of study enables a rational reference system to be constructed for: fixing rates for different types or consumers (rate studies also require other important data on such aspects as consumption elasticity, etc.); for valuing energy offered by occasional suppliers of the system (surpluses from industries that are self-supplying); for analysing transmission losses in studies of possible line systems, power station sites and types of interconnexions, etc.

The calculations given as an example in this paper are too limited in scope to produce valid results and are merely intended to illustrate the method. It is hoped that the findings of comprehensive studies will soon be issued, obtained with the help of computers.

/The basic

The basic problem in planning an electricity service is to decide upon the overall installations, particularly generating plants and primary transmission lines, that will be required to satisfy consumption, with due consideration to the need for a reliable service, at a minimum cost. Other conditions or injunctions are sometimes specified in addition to that of minimum cost, such as less expenditure of foreign currency, intensified use of labour, minimum fuel consumption, etc.

Once the foregoing problem has been resolved by trial and error, by linear programming techniques or by other ad hoc methods, as, for example, that of the coefficient of installation value, it still remains to determine how much of the total cost should be allotted to each client (a problem of rate-fixing) or, to put it more generally, determine how much it costs to supply an arbitrary consumption forming part of the total. This problem is more important than that of determining the marginal cost of supplying an additional arbitrary consumer, since such cost may vary enormously from one year to another. In fact, since installations are always made in large blocks, temporary power and energy surpluses are inevitably produced. Sometimes, installations of a given type are made first, to be supplemented over the long term by others with different characteristics; this explains why there are special supplies of energy at certain seasons of the year or at certain hours of the day. Surplus energy of this type should be dealt with on a special basis, with low rates and specific contracts, usually of a short-term nature.

The most important cost is that which affects energy as a whole; nevertheless, some authors who are interested in marginal costs have introduced the concept of "the marginal cost of development", which is the cost of the installations required to meet an increment in consumption at all its levels during a given period, a figure which it may be important to know as well.

If the premise that the consumer is at complete liberty to request energy and power at any time is accepted, the demand curve will take on a characteristic shape with peak periods, which are generally more pronounced. In this case, the cost of supplying electricity will be higher than if an equal

/amount of

amount of energy is consumed with less variation in the consumption curve. It is therefore very important, in order to provide as economical a service as possible, to take account in the rates of the disparity in the cost of different types of consumption. When this has been done, the consumer will try to obtain energy at the lowest possible price that is compatible with the use to be made of it, thereby shifting towards the lower-price zones and generally improving the shape of the demand curve, as well as reducing the total cost of the service for the community and freeing domestic capital resources at the disposal of the economy for utilization by other productive activities. Studies undertaken in other countries show that peak electricity consumption is fairly sensitive to rate-fixing on an hourly basis, even if total energy consumption is not.

Electricity consumption is a function of time and, because it includes the statistical behaviour of a great many customers, can be predicted within relatively well-defined limits. This does not mean that it is easy to make long-term forecasts on a yearly basis, or even short-term forecasts for daily load dispatch purposes. In the former case, prospecting techniques, sampling, statistical analysis, correlation with industrial indices, wage levels, etc. have to be used; in the latter, a watch must be kept on the rapid daily changes in temperature, atmospheric luminosity, etc.

In addition, the installations for supplying electric energy have specific characteristics which determine their service ability. Thermal plants require a certain length of time to be put into action, proper fuel storage and provision, regular maintenance check-ups, occasional outage for failures, etc.; hydraulic plants have the same requirements in an even greater degree and, in addition to those limitations, are dependent upon the characteristics of their water catchment areas, and can alter their energy-producing capacity radically in accordance with meteorological changes, orographic accidents in mountainous zones (landslides), etc.

In a mixed electric system, based on thermal and hydraulic plants, the best method of operation is that which minimizes variable costs; this requires a detailed analysis of the right use of the long- and short-term storage capacities of overflow reservoirs, artificial lakes and dams of the hydraulic

/power stations.

power stations. The proper techniques have been developed and enable operational instructions to be given to load dispatch centres, on, for example, the maximum and minimum levels to be observed in the reservoirs according to hydrological statistics for the preceding months.

2. Method of calculating service cost

The method suggested consists of the formulation of various logico-numerical steps adapted to the use of computers (e.g. electronic computers), since, in view of the fortuitous nature of the phenomena involved in hydro-electric generation (which vary according to probability functions), a large number of operations is necessary to obtain worthwhile results.

An analysis is made of service cost in a specific calendar year for which the consumption curve is known. One example would be a series of 2 x 12 x 24 numbers, each of which represents average hourly demand during typical working days and holidays in each of the 12 months of the year.

In addition, it is assumed that a system of installations has been chosen for the service required. This system will consist of existing hydroelectric and thermal plants and/or those that are to be built. Approximate and less laborious methods (value coefficients, linear programming, etc.) will normally have been used to determine that such a system is the most economical set of installations for meeting consumption requirements. Nevertheless, the method proposed may also be useful for comparing total energy costs in a number of different sets of installations and therefore for indicating the most appropriate.

With the foregoing data at hand, it will suffice to assume certain hydrological conditions for the year in question to be able to decide upon the way in which the system should operate. This is a problem which can be solved by other well-known means.

As each hydrological year will naturally have a different service cost, it will be necessary to make the calculations for an adequate number of hydrological years and then find the average. The method might be shortened by calculating the hourly cost distribution for a single average year of operation, in other words, a year in which each power station generates the

/average in

average in respect to its total generation during the different hydrological years. However, owing to the non-linearity of the curves in figure III, which have been used to indicate the way in which the total power station cost is distributed between the different grades of power in the system, this hourly cost calculated on the basis of the average year is not the same as the average hourly cost in the different years, for a given hour. The discrepancy which may result from the use of the simplest procedure has not yet been estimated, but since it may be small it is obviously unnecessary to resort to the more laborious method.

As to the choice of hydrological years, the best procedure is to study the largest possible number of years and to use statistics covering some 30 consecutive years, which is quite inexpensive if electronic computers are available. Without these machines, operations would have to be studied during a shorter period or even perhaps during a representative mean year in hydrological statistics. It should be borne in mind that if the simple statistical average is adopted (expressed in terms of flow to the turbine), the values obtained may be far from correct since, for instance, in a system that is predominantly hydraulic and uses thermal energy in the driest years only, the average statistical year will not require any thermal energy.

In these cases, it would be preferable to study representative years - dry, medium and damp - and obtain an average with coefficients that are significant to a sufficiently high degree.

For each hydrological year, there will be a series of figures indicating hourly demand coverage in each power station of the system. On this basis, a calculation can be made of the thermal energy that should be generated every hour, which is an important factor in the allotment of variable costs.

(a) Distribution of variable cost

Since thermal variable costs are substantial, their distribution per hour has an appreciable effect on results. In the first place, a clear distinction has to be made between two basic types of thermal energy: the first, generated because of a deficit in installed hydraulic capacity (we will call it thermal peak energy) and the second, generated because of an additional deficit of hydraulic energy (thermal base energy).

/Thermal peak

Thermal peak energy should undoubtedly be charged to the hours in which it is actually produced. Thermal base energy, however, can be generated more or less arbitrarily within a given period. If the water storage facilities are adequate, the period may be a whole year; if they are limited, it may be a season, a month, weeks or days. In view of this, it is considered that the variable costs of thermal base energy should logically be charged to all the hours that make up the relevant period and not only to those when it is, or is assumed to have been, generated. In actual fact, therefore, the thermal base variable cost is divided among all the kWh generated during the period in question, with the sole exception of the thermal peak kWh.

Hydroelectric variable cost is very small. In common with thermal base energy cost, it is charged on an equal basis to all the kWh generated during the period, with the logical exception of thermal peaks.

In short, there are two basic variable costs, the first for thermal peak kWh and the second for the remainder. The second derives from the equitable distribution among the kWh of hydraulic variable costs plus thermal base costs.

(b) Distribution of fixed cost

If a graph is made of average hourly demand (see figure I, curve 1) during the 8,760 hours in the year, and of the annual cost of the installations required to supply each demand level (see again figure I, curve 2), each kWh consumed at a given level of demand can be allotted a cost equal to the annual cost of the facilities needed to serve that level divided by their annual utilization.

The annual utilization of a capacity level can easily be obtained from the energy-power (or parabolic) curve (see figure II).

As a first approximation, it may be assumed that all demand levels have the same cost per unit of power. This assumption is, however, refuted by the recognized fact that both hydraulic and thermal power stations tend to have a lower cost per unit of power when the plant factor of their designs decreases.[1] In other words, it is more expensive to generate base power

[1] See, for example, A. Bennett et al., Influencia de la magnitud y características de una central hidroeléctrica en el costo de las obras.

/ than peak

than peak power. In order to take this factor into account, a curve is used that links up power costs with the plant factor in both hydraulic and thermal power stations (see figure III). This is a curve of relative values only since the absolute cost of power derives from the real value of the installations of the system.

Studies on the way in which the system operates will give rise to figures such as Va and Vb which indicate each plant's daily contribution of energy and power. In figure Va an hourly consumption curve is used and in figure Vb the corresponding parabolic curve. The latter may be quicker to obtain. In practice, the power stations work partly as a base plant and partly as a peak plant. Thus, for instance, the same power station appears in figure Va as supplying energy at power level "j-k", "j" and "j + n". Hence, the cost of the power station must somehow be distributed among these three levels. One way of doing this is to weigh each one by its corresponding "s" factor in accordance with the curve in figure III.

In a simplified study, similar power stations could be grouped together and dealt with as a single unit, especially if their behaviour coincides during various hydrological years.

Cost distribution might be made in accordance with other criteria, such as the amount of energy supplied by the power station at a given level, or the maximum demand that it can meet at that level, etc. What seems to be the most satisfactory criterion, however, is that which divides the cost in accordance with the costs of equivalent power stations constructed expressly with a view to the utilization of the power stations at each level. Admittedly, in the case of hydraulic power stations no correlation can be made between cost and energy if energy is not taken into account, and still less between cost and energy if power is discounted. Nevertheless, with a closer approximation, a curve can be made that shows the relative cost (known as "S") of power stations in terms of utilization factor, in other words, of a parameter deriving from power and energy as a whole. Each plant has its own curve of this kind, but, in order not to complicate the procedure unnecessarily the same relative curve has been applied to all of them.

This procedure is considered justifiable in the case of Chile because the abundant hydroelectric resources in the interconnected area allow for

/the development

the development of plants whose unit costs are on the same "S" curve, although, after a very long term this curve may ultimately follow a different course or lose its validity if water becomes scarce. In order to clarify the use of this curve, an example is given under "Fixed cost" below.

The fixed costs of thermal plants also vary according to the utilization factor. A plant designed for continuous operation will cost more at the outset than one intended to supply peaks since, in order to raise thermal yield, it is necessary to have higher pressure and temperature. An "S" curve will therefore exist for plants of this kind.

(c) Calculation formulas

The detailed process of calculation may be summed up as follows:

C_i^j = cost of kWh at hour i, demand level j (figure I, curve 1)

C_i^j, v = variable cost of C_i^j; C_i^j, f = fixed cost C_i^j

$C_i^j = C_i^j\ f + C_i^j,\ v$

Wh = Hydraulic kWh generated

Wt = Thermal kWh generated

Wtp = Thermal peak kWh

Wtb = Thermal base kWh

Ch = Hydraulic variable cost, per kWh

Ct = Thermal variable cost, per kWh

Variable cost

If the energy at i-j is hydraulic or thermal base:

$$C_i^j,\ v = \frac{Ch.Wh + Ct\ Wtb}{Wh + Wtb} \qquad (1)$$

If the energy at i-j is thermal peak:

$$C_i^j,\ v = Ct \qquad (2)$$

/Fixed cost

Fixed cost

Cj = Annual cost per kW at power level "j" (figure I, curve 2)

Tj = Hours of utilization of power "j"

If the parabolic curve in figure IIa is used

$$Tj = \frac{\Delta Ej}{\Delta Dj} \quad \text{(hours)}$$

In practice, the parabolic curve will be based on "so much per unit" and not on kWh since it remains much the same from year to year (see figure IIb).

The calculation of Cj is made with the help of the curves in figure III. If P1, P2, Pn etc. are the annual cost of the different power stations 1, 2 and n, and Pj the charge corresponding to level j of the power station, the following should be obtained:

$$\sum_{\alpha=1}^{n} P_{\alpha}^{j} = Cj \qquad (3)$$

$$\sum_{j} P_{\alpha}^{j} = P_{\alpha} \qquad (4)$$

If f_{α}^{j} is the utilization of the power station α and W_{α}^{j} the power of α at level j, S_{α}^{j} is obtained from figure III S_{α}^{j} and the following equation made:

$$P_{\alpha}^{j} = P_{\alpha} \frac{W_{\alpha}^{j} S_{\alpha}^{j}}{W_{\alpha}^{j} S_{\alpha}^{j}} \qquad (5)$$

The following example is given to illustrate the use of formula (5):

Power station A of 100 mW supplies:

60 mW with plant factor 90 per cent at level j_1, and

40 mW with plant factor 30 per cent at level j_2

The annual cost of the power station = US$ 2,400,000

From figure III:

$S^{j1} = 1.00$

$S^{j2} = 0.75$

$W^{j1} = 60$

$W^{j2} = 40$

$/\Sigma S_{\alpha}^{j} W_{\alpha}^{j} =$

$$\sum S_\alpha^j W_\alpha^j = 0.75 \times 40 + 1.00 \times 60 = 90$$

$$p^{j1} = \frac{2,400,000\ (1.00 \times 60)}{90} = \text{US\$ } 1,600,000$$

$$p^{j2} = \frac{2,400,000\ (0.75 \times 40)}{90} = \text{US\$ } 800,000$$

Cost per kW of power station A at peak: $\frac{800,000}{40,000}$ = US$ 20

Cost per kW of power station at base: $\frac{1,600,000}{60,000}$ = US$ 26.66

The fixed cost per kWh at level j, hour i will be:

$$C_i^j,\ f = \frac{Cj}{Tj} = \frac{\Delta D\ j}{\Delta E\ j} \cdot \sum \frac{P_\alpha\ S_\alpha^j\ W_\alpha^j}{\sum_j\ S_\alpha^j\ W_\alpha^j} \qquad (6)$$

Once C_i^j has been calculated with the aid of the preceding formulas, the total average cost of a kWh at hour i can be calculated as follows:

$$W_i = \frac{\sum_j C_i^j}{(D_m)_i} \qquad (7)$$

$(D_m)_i$ is hourly maximum demand at hour i

(d) Comments

The values of W_i can then be used to calculate service costs for customers with arbitrary consumption curves.

Arbitrary consumers

If the consumption curve is d (i), the average service cost per kWh will be

$$W_m = \frac{\sum_i Wi\ d\ (i)}{\sum_i d\ (i)} \qquad (8)$$

Apart from other uses, it is suggested, for example, that the energy offered by a private plant, wishing to sell surpluses to the system, might be valued in a similar way.

Valuation of transmission losses

These losses are roughly proportional to the square of demand, which enables the average value of each kWh lost to be calculated in the following way:

$$W_p = \frac{\sum_i Wi\ d^2\ (i)}{\sum_i d^2\ (i)} \qquad (9)$$

/3. Application

3. Application of the proposed method to the Chilean interconnected system in 1959

In order to illustrate the general method suggested in the first part of this paper, it has been applied to the area stretching between the 32nd and 39th parallels, south latitude, in Chile (see map I). This area is supplied by a system that is predominantly hydraulic but also generates a certain amount of thermal energy.

The study carried out is retrospective in the sense that the year chosen was one for which information was available on the consumption curve and generation characteristics. Hence, the study differs from anything else that has been done with an eye to future programming or rate-fixing and merely serves to illustrate a method.

Furthermore, as electronic computers are not yet available, the calculations were made with the aid of office equipment which made it necessary to simplify the basic data. Annual consumption was exemplified in eight daily curves, which corresponded to typical working days and holidays in the four quarters of the year. Fixed charges were first divided into quarters and then into hours for the typical days. Variable charges in hydraulic plants were considered to be non-existent (being incorporated into fixed charges) and those of thermal plants only were taken into account. Other simplifications will be explained later.

(a) Power plants

Generating stations were grouped as follows:

(i) The power plant "CCE" which represents the Volcán, Queltehues, Maitenes and Florida plants belonging to the Chilean Electricity Company (Compañía Chilena de Electricidad, Ltda.) and other small plants, which do not belong to ENDESA but to industries in the same area.

(ii) The hydroelectric plants "Sauzal" and "Sauzalito", situated in the cordillera inland from the town of Rancagua.

(iii) The hydroelectric plant "Cipreses", situated in the cordillera, near the town of Talca.

(iv) The hydroelectric plant "Abanico", situated in the cordillera, near the town of Los Angeles.

/(v) The

(v) The power plant "Térmica", corresponding to the Laguna Verde and Mapocho plants (the last-named of which is situated in Santiago); however, the capacity they are considered to have is somewhat different from the real figure.

The main characteristics of the power plants - capacity, cost, etc. - are presented in table 1.

(b) Consumption

Consumption, which was 2,131.75 x 10^6 kWh in the year, was divided into four quarters. It was assumed that each quarter contains only two typical days, one corresponding to a working day and the other to a holiday.

The seasonal distribution of consumption and the contribution made by each power plant are indicated in table 2.

In table 2 what is known as seasonal maximum demand is instantaneous maximum demand during the period. It is 5 per cent higher than hourly maximum demand. Instantaneous annual maximum demand occurs in winter (415 mW) and is 37 mW less than the system's installed capacity. The surplus is composed of supplementary capacity for the power plants, losses, reserves for cases of break-down or outage, and real but temporary surpluses of installed capacity, etc. When the balance is divided among all the power plants, the result is known as the aliquot capacity of the plant (the share of annual maximum demand that corresponds to the plant).

(c) Determination of variable costs

The procedure utilized is the same as that explained in paragraph 2(a) (distribution of variable cost) but is applied to each quarter separately.

The formulas applied were (1) and (2) in paragraph 2(c) on calculation formulas.

First quarter. No variable charge. All energy is hydraulic.

Second quarter. The curves for the daily operation of the system show that thermal peak energy is 0.79 x 10^6 kWh and that thermal base energy is 36.21 x 10^6 kWh. If thermal variable cost is considered to be equal to 16 mills/kWh, the overall variable cost of energy during the period in off-peak hours is 1.06 mills and at peak hours 1.51 (at 8 p.m. on working days).

/Third quarter.

Third quarter. Thermal peak energy is 12.4, 12.89 and 31.62 x 10^6 kWh respectively during the three hours of maximum demand (7 p.m., 8 p.m. and 9 p.m. on working days). Thermal base energy is 23.44 x 10^6 kWh. When the costs have been distributed, a variable charge of 0.64 mills/kWh is obtained for off-peak hours and of 1.07, 1.09 and 1.69 respectively during the three hours of maximum demand.

Fourth quarter. Thermal peak energy is 76 x 10^6 kWh and base energy 8.9 x 10^6 kWh. The variable costs are 0.27 mills/kWh for off-peak hours and 0.31 during peaks (9 p.m. on working days).

(d) Seasonal distribution of fixed cost of the power plants

The seasonal distribution is made by taking the curve in figure III which gives the values of "S" and using a formula similar to formula (3) in paragraph 2(c) on Calculation formulas, except that j indicates the quarter under consideration.

In order to simplify the calculations, it was assumed that the Abanico plant is divided into two plants, one of 72 mW (aliquot capacity) which supplies power throughout the year, and the other of 28 mW, which does not operate in summer. Similarly, the "Térmica" (steam power plant) is separated into three units of 20, 10 and 16 mW respectively, operating in autumn, winter and spring, in autumn and winter and in winter only. It is assumed that the cost per kW in the steam power plants is independent of the plant factor, i.e. S is constant.

The annual percentage charges on investment, assessed by the sinking fund method, with an interest rate of 10 per cent, amortization in 50 years for hydroelectric plants and 33 years for thermal plants, and with 2 per cent annually for operation and maintenance costs, are:

12.085 per cent for hydroelectric plants

12.430 per cent for thermal plants.

Owing to the fact that the data available on the cost of the power stations and transmission systems were calculated on the basis of 1958 values, the figures were converted to dollars at the rate prevailing in that year.

The method of calculation and results are given in table 3.

/(e) Hourly

(e) Hourly distribution of fixed and variable costs

Once the quarterly charges of the different power stations (see paragraph 3(d)) were determined, the quarterly total was obtained. Then, in order to distribute the costs by demand level, the quarterly total was divided in accordance with formula (6), which was adjusted to allow for the fact that the power stations were considered in the aggregate:

$$C_i^j, f = \frac{\Delta Dj}{\Delta Ej} \cdot \frac{PSjWj}{\sum_j Sj\ Wj} \qquad (6a)$$

Here P is the sum of the plants' costs during the quarter ($P = \sum_{\alpha} P_{\alpha}$). It is stressed once again that this method was used in order to shorten the calculations in the absence of better facilities.

It should be noted that 5 per cent of the additional capacity required to attend seasonal instantaneous maximum demand was distributed between the hour of hourly maximum demand and its two immediate neighbours, as it is seldom known in which of the three instantaneous maximum demand really occurs during the quarter.

Table 4 exemplifies the method of calculation, and is self-explanatory.

(f) Results and observations

The results of the foregoing calculations are summed up in figures IVa and IVb which concurrently express maximum hourly demand and hourly service cost as a function of time.

The special case under study shows only a few of the characteristics of hourly service cost that may be expected in an electric power system. One of them is naturally the marked variation in cost between hours of maximum demand and the remainder. Another is that the cost of off-peak hours on working days and holidays is almost the same. Nevertheless, the study fails to bring out the big disparity between the average seasonal cost of the system in summer and in winter, a disparity which was due to the fact that 1959, the year under consideration, was wetter than usual. A comprehensive study covering a number of hydrological years would have exposed this difference from the fact that charges for thermal energy in winter were higher.

/4. Conclusions

4. Conclusions

It is perfectly possible to make an accurate analysis of the way in which a complicated electric power system works and to calculate the cost of supplying electricity during any hour whatsoever if high speed computers are used. The abridged methods which have normally been adopted up to now are appropriate for very simple systems only. For the others, the more extensive and satisfactory information that can be obtained with the aid of computers will pay the cost of the relevant studies many times over.

If computers are to be used to help in the execution of the studies, programming must be based on a rational and stringent methodology. This will indirectly lead to greater understanding of the variables involved and of their relative importance.

One example of this procedure is the description of the method by which the hourly cost of supplying electric power was calculated for ENDESA's interconnected system, a calculation which had to be worked out in such a way as to be clearly understandable at every step.

It is naturally a question of individual judgment whether or not the premises inherent in that method are adopted, but in any case they have been sufficiently clearly defined and laid down to enable them to be revised or improved later. The point on which particular stress has been laid, however, is the virtually unlimited potential of these new tools, which makes it possible to approach a problem in a logical way with no more concern for its degree of difficulty than in as much as it affects the time for which the equipment is needed. Thus, with the Montecarlo method, the foregoing study could be perfected through the introduction of other incidental factors, such as the possibility of defects in the equipment and the interconnexion lines or hydrological variations.

ENDESA's present interconnected system is still fairly small, but these studies will be increasingly useful, since whenever installations are doubled - which happens about every seven years - their complexity will increase more than twofold.

/SUMMARY

SUMMARY

The existence of high speed computers enables highly effective logico-mathematical methods to be applied to the study of interconnected systems based on hydraulic and thermal resources.

A description is given of a method for assessing the electric energy produced during the different hours of the year, as a function of hydrological conditions, of the power plants and of the daily and seasonal variations in consumption. This method may be very useful for making a comparative study of possible programmes and rate policies.

In the authors' opinion, the method proposed in this study has the virtue of being of general application, fairly simple and easy to use.

Briefly, it may be said that demand during the different hours is divided into levels of capacity. The fixed costs of each level, which are ascertained by a method suggested in this paper, are then distributed among the total number of hours that the said level is used. The result is the fixed cost of each capacity level during a given hour.

The sum of the fixed costs for all the levels used in a given hour, divided by demand during the same period, will give the unit cost of energy in that hour.

The applied example given here shows the big difference, on typical working days, between cost at peak hours and cost at other times. But the example fails to reveal the gap between summer and winter costs. Its inability to do so is due to the fact that it is based on a single and very wet hydrological year, i.e. 1959. In practice, costs should be forecast on the basis of hydrological statistics for a considerable number of years which should move through the year for which the production costs are to be ascertained. The average obtained from the results will give the probable average cost. It is advisable for high speed computers to be used for this type of study.

/Table 1

Table 1

Power plant	Type	Installed capacity mW	Aliquot capacity mW	Unit cost (dollars/kW)	Total cost (dollars x 10^6)	Annual cost (dollars x 10^3)
CCE	H	115	106	410	47.15	5 698.0
Sauzal	H	76	70	390	29.64	3 582.0
Cipreses	H	101	93	370	37.37	4 516.2
Abanico	H	110	100	340	37.40	
Abanico A	H	79.2	72	346	27.40	3 311.3
Abanico B	H	30.8	28	325	10.00	1 208.5
Thermal A	T	21.8	20	270	5.90	713.1
Thermal B	T	10.8	10	270	2.90	350.4
Thermal C	T	17.4	16	270	4.70	568.0
Total		452	415			19 947.5

/Table 2

Table 2

USE OF ALIQUOT CAPACITY AND ENERGY, BY POWER PLANTS

	First quarter	Second quarter	Third quarter	Fourth quarter	Total
Hourly maximum demand (mW)	325	380	395	370	
Seasonal maximum demand (mW)	341	399	415	389	
Energy generated (kWh x 10^6)	461.86	549.05	582.82	538.02	2 131.75
CCE Capacity (mW)	106	106	106	106	
Energy (kWh x 10^6)	129.26	117.28	164.03	191.82	602.39
Sauzal					
Capacity (mW)	70	70	70	70	
Energy (kWh x 10^6)	106.71	93.36	99.93	78.37	378.37
Cipreses					
Capacity (mW)	93	93	93	93	
Energy (kWh x 10^6)	104.24	132.86	125.88	119.88	482.86
Abanico					
Capacity (mW)	72	100	100	100	
Energy (kWh x 10^6)	121.65	168.55	165.98	138.95	595.13
Térmica					
Capacity (mW)	-	30	46	20	
Energy (kWh x 10^6)	-	37.00	27.00	9.00	73.00

/Table 3

Table 3

DISTRIBUTION OF ANNUAL FIXED COST OF POWER PLANTS, BY QUARTERS

Plant	Plant factor percentage	Annual cost as a function of plant factor	Share of annual cost	Annual cost (dollars x 10^3)
		First quarter		
CCE	52.0	0.79	24.3	1 384.6
Sauzal	65.0	0.83	25.9	927.7
Cipreses	47.8	0.78	24.5	1 106.5
Abanico				
Abanico A	74.5	0.86	25.6	847.6
Abanico B	-	-	-	-
Termica A	-	-	-	-
Termica B	-	-	-	-
Termica C	-	-	-	-
Total				4 266.4
		Second quarter		
CCE	46.7	0.77	23.7	1 350.4
Sauzal	56.3	0.80	24.9	891.9
Cipreses	60.2	0.81	25.5	1 151.6
Abanico				
Abanico A	73.2	0.85	25.3	837.6
Abanico B	73.2	0.85	34.0	410.9
Termica A			33.3	237.7
Termica B			50.0	175.2
Termica C			-	-
Total				5 055.3
		Third quarter		
CCE	64.6	0.83	25.5	1 453.0
Sauzal	59.1	0.81	25.2	902.7
Cipreses	56.4	0.80	25.2	1 138.1
Abanico				
Abanico A	71.3	0.84	25.0	827.6
Abanico B	71.3	0.84	33.6	406.1
Termica A			33.3	237.7
Termica B			50.0	175.2
Termica C			100.0	568.0
Total				5 708.4
		Fourth quarter		
CCE	75.6	0.86	26.5	1 510.0
Sauzal	46.3	0.77	24.0	859.7
Cipreses	53.7	0.79	24.8	1 120.0
Abanico				
Abanico A	59.7	0.81	24.4	798.5
Abanico B	59.7	0.81	32.4	391.5
Termica A	-	-	33.3	237.7
Termica B	-	-	-	-
Termica C	-	-	-	-
Total				4 917.4

/Table 4

Table 4

	1 Hour	2 Demand	3 ΔD_j	4 ΔE_j	5 T_j	6 P
Unit		mW	mW	kWh x 10^6	Hours	1 000 x US$
Formula		Figure I, curve 1		Figure II	$\frac{\Delta Ej}{\Delta Dj} \times 10^3$	Table 3
Second quarter						
	4T	159.6	4.6	9.30	2 021	5 055
	2F	160.2	0.6	1.17	1 948	5 055
	22T	335.2	8.4	1.84	219	5 055
	20T	380.0	11.0	0.79	73	5 055

	7 F^j	8 S^j	9 C_i^j,f	10 C_i^j,v	11 C_i^j	12 W_i
Unit	1/1	1/1	mills/kWh	mills/kWh	mills/kWh	mills/kWh
Formula	T_j/T_t	Figure III	6 (a)	Paragraph 2.3	$C_i^j,f + C_i^j,v$	$\frac{\sum_j C_i^j}{(Dm)_i}$
	0.92	1.00	7.09	1.06	8.15	7.65
	0.89	0.99	7.28	1.06	8.34	7.65
	0.10	0.72	47.08	1.06	48.14	11.34
	0.03	0.96	187.82	1.51	189.33	25.50

Note: In the present table of 12 columns, some of the hourly demand values have been picked at random. In practice, all the different demand values should be listed consecutively from the lowest to the highest. (In this case, there are 48 values corresponding to the 24 hours of a working day and 24 of a holiday.)