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A CONTRIBUTION TO PEAK LOAD PRICING : THEORY AND APPLICATION

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ABSTRACT

The present paper attempts at a contribution to peak load pricing, in both theory and application. The general result from the traditional theory that charges the off-peak consumers marginal operating costs only and the peak users marginal operating plus marginal capacity costs, since it is the on-peakers who press against capacity, has already been called into question in the literature. It has also been shown that the equity norms are violated in the traditional peak load pricing, whereby off-peak users pay no capacity charges, but are supplied output out of the capacity, 'bought/hired' by the on-peakers. Theoretical attempts at modification have proved that the traditional conclusion holds only for homogeneous plant capacity (e.g., in one plant case), and in economic loading of two or more plants, the off-peak price also includes a part of capacity costs. This paper, however, shows that if the off-peak period output is explicitly expressed in terms of capacity utilisation of that period, the result will be an off-peak price including a fraction of the capacity cost in proportion to its significance relative to total utilisation. This would appear as a general case, irrespective of the nature of generation technology, that is, even when there is only one plant. We also give an illustration by estimating marginal costs and peak load prices using time series data on the Kerala power system. Where the data are incapable of yielding the required statistically determined long-run relationship among the variables under study, we propose a simple and viable method of using discrete ratio of increments in lieu of a marginal value.

JEL Classification: C22, D40, L94

Key words: Peak, off-peak, pricing, capacity utilisation, marginal costs, Kerala

"Hypotheses non fingo." [1]

Isaac Newton.

1. Introduction

The literature on peak load pricing essentially emerged in response to problems faced by most public utilities, such as electricity supply industry[2] and telecommunications, whose products are economically non-storable and demand is time varying. These characteristics tend to result in non-uniform utilisation of capacity. Here peak load pricing offers an indirect load management mechanism[3] that meets the dual objectives of i) reducing growth in peak load ('peak clipping'), thus nipping the need for capacity expansion, by charging a higher peak price, and ii) shifting a portion of the load from the peak to the base load plants ('valley filling'), thereby securing some savings in peaking fuels, by charging a lower off-peak price. This thus ensures an improvement in capacity utilisation as well as a cut in operating and capacity costs. The context of public utilities in such peak load problem led the economists (Boiteux 1949; Steiner 1957; Hirshleifer 1958; Williamson 1966; to name a few) to model pricing rules based on maximisation of social welfare rather than profits.[4]

The general result from the traditional theory charges the off peak consumers marginal operating costs only and the peak users marginal operating plus marginal capacity costs, since it is the on-peakers who press against capacity. Following Turvey (1968), Crew and Kleindorfer

(1971) relax the assumption of homogeneous production capacity, and considers diverse technology, as efficient provision for a periodic demand generally implies an optimal plant mix of different types of capacity with different relative energy and capacity costs. They show that the traditional conclusion holds only for homogeneous plant capacity (e.g., in one plant case), and in economic loading of two or more plants, the off-peak price also includes a part of capacity costs. Wenders (1976) argues that the application of peak load pricing theory to the electric utility, where cost minimisation requires that heterogeneous electric generation technologies be used to meet demands of different duration, stands to modify the usual result. He shows that with heterogeneous technology, off peak marginal cost prices almost always should include some marginal capacity costs *a la* marginal capacity cost savings under certain circumstances. But Joskow (1976), in his comment on the paper, clarifies that these off peak prices can also be rewritten in terms of marginal energy costs only, in a way to validate the traditional result. Panzar (1976), on the other hand, proposes that the usual peak load pricing result is due to the fixed proportions technological assumption employed in the traditional theory and is not a consequence of the fundamental nature of the peak load problem. He shows in particular that in a framework of neoclassical technology of short run decreasing returns to scale, consumers in all periods make a positive contribution toward the cost of capital inputs.

It goes without saying that the equity norms are violated in the traditional peak load pricing, whereby off-peak users pay no capacity[5] charges, but are supplied output out of the capacity, 'bought/hired' by the on-peakers. True, the accounting sense of pricing is satisfied here (total cost is recouped, capacity cost being drawn from on-peakers); but its 'cross-subsidisation' stands inimical to fairness in tariffing. Weintraub (1970) sees a 'free ride' problem in the peak load pricing, and argues that

'The P-H [peak hour] buyers have every reason to claim that the 'property' - the capital facility - is theirs, that they pay for it and that others can use it only at a price in order to reduce the net price to them - the P-H users. An outcome which allocates common costs to only the peak-users thus has some disquieting equity features which go to the roots of private property, income distribution, and the diffusion of consumer well-being.' (Weintraub 1970: 512). He therefore suggests 'an alternative solution', ('output maximisation') that is, setting prices such that peak plus off-peak output are maximised, subject to the constraint that costs are covered. For him it is possible that peak price is greater than or less than or equal to off-peak price (p. 513). But this would detract from the peak load pricing as a load management strategy: the peak price must *always* be greater than the off-peak one in order to improve capacity utilisation at a desirable uniform level through 'peak clipping' and 'valley filling'; at the same time it should be so structured as to ensure equity concerns by apportioning capacity costs, (which are common to all periods), to both the peak *and* off-peak users by their importance relative to total use. The present paper seeks such a solution, especially in the context of electricity supply.

There is yet another, technical, reason why off-peakers also should bear capacity charges. Power consumption rises over time, with increasing number of consumers and of electrical gadgets in use, as well as increasing intensity of their use. Additional plants are required to meet not only the rising peak load but also the expanding base load. Thus the additional capacity costs involved in installing new base load plants must be borne by all the consumers, irrespective of the period of use, as the base load plants are continuously used in both the periods. This is why in the diverse technology framework, implied in economical load scheduling, off-peakers are also charged a part of capacity costs. As already stated, in Crew and Kleindorfer (1971) and Wenders (1976) this appears in terms of an expression for capacity and running cost savings in line with the logic of optimum plant mix, without yielding a practical rate structure in a format like that of peak price. Our methodology does yield such a one.

In the next section we present the traditional peak load pricing theory and discuss the implications of the assumptions involved. Section 3 introduces, with a view to facilitating our further discussion, some of the important techno-economic characteristics of an electric utility. Section 4 presents the modified peak load pricing model, followed by an illustrative application of the pricing rule in a new practical framework. The last section concludes the study.

2. The Traditional Theory

In its simplest version (e.g., Steiner 1957), the model assumes two independent loads, each of equal length, in a demand cycle (a 'day') denoted by $D_o(P_o)$ and $D_p(P_p)$. The peak load problem results from the

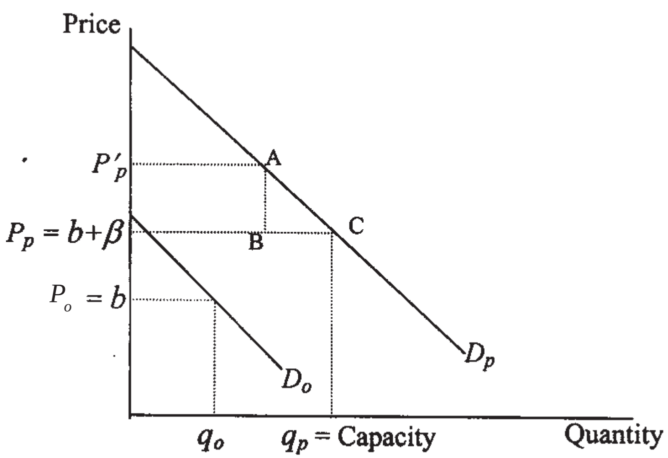

Fig. 1: Traditional peak load pricing

assumption that $q_o < q_p$ = capacity, where q_t is the quantity demanded in period t (t = peak (p); off-peak (o)); this means that $D_o(P_o)$ lies everywhere below $D_p(P_p)$. The independent demands denote that one period price has no effect on the other period quantity demanded. There is only one type of plant available for generation (homogeneous technology), and investment is always forthcoming for sufficient capacity to meet demand. The supply costs are linear - β being the per unit capacity charges per 'day' and b, the per unit operating charges per period. Then a unit output demanded in peak period costs $b + \beta$, as demand presses against capacity, necessitating additions, and that in off-peak period costs only b, as no additional capacity is required.[6] Figure 1 illustrates this two-period solution. The two prices are optimal in the sense of maximising the net social welfare. Any other price would involve a net loss in welfare; for example, at price P'_p, there would be a net welfare loss of ABC. A formal discussion of the solution is given below.

The traditional peak load pricing rule is obtained from the first-order condition for the maximisation of net social welfare, defined by

$$W = \sum_t \int_0^{q_t} P_t(y_t)\,dy_t - C(q_t)\,, \qquad \text{.... (1)}$$

where $P_t(q_t)$ is the inverse demand function,[7] assumed to be periodically independent;[8] $C(q_t)$ is the total cost, composed of capacity and operating components, i.e.,

$$C(q_t) = \beta q_p + b \sum_{t=o,p} q_t\,, \qquad \text{.... (2)}$$

where q_p is the peak period demand (= capacity), q_o, off-peak period demand (< capacity), β and b are the per unit capacity cost per cycle (e. g., a day) and operating cost per period respectively, and t denotes different periods (say, peak (p) and off-peak (o)). Maximisation of the net social benefits yields the following optimal peak (P_p) and off-peak (P_o) prices:

$$P_o = b, \text{ and } P_p = b + \beta. \qquad \text{…. (3)}$$

Thus the on-peakers are to bear the entire capacity costs, and the off-peakers are favoured by being charged only operating costs.

It is generally recognised that the peak load problem emerges from the (oft-factual) assumption that $q_{\text{off-peak}} < q_{\text{peak}}$ = capacity, but it is less understood that the solution results from the implicit assumption of the independence of off-peak output from capacity, and thus, as Panzar (1976: 521) rightly points out, has nothing to do with the 'fundamental nature of the peak load problem'. It is traditionally assumed that whenever a unit of capacity is installed at a cost β, it becomes available for demand in *all* periods; off-peak demand also is met from this capacity; yet this relationship is not explicitly incorporated into the cost equation. And thus the off-peak price comes out without the capacity cost component! Herein lies the significance of equity concerns in the sense of Weintraub (1970). It can be shown that if the off-peak period output is explicitly expressed in terms of capacity utilisation of that period, the result will be an off-peak price including a fraction of the capacity cost in proportion to its significance relative to total utilisation. This would appear as a general case, irrespective of the nature of generation technology, that is, even when there is only one plant, in contrast to Crew and Kleindorfer (1971) and Wenders (1976). The objective of this paper is thus to illustrate this as follows.

3. Some Techno-Economic Characteristics of Electric Utility

As already noted, electric utility is characterised by an economically non-storable product and a periodically fluctuating load. The load on a utility is the varying sum of all the residential, commercial, and industrial loads, each varying by time of day in its own way. A typical (smoothed) system *load curve* (as a plot of load, in kilowatt (kW), against the time at which it occurs) is given in the first part of Fig. 2. There is a pronounced valley in the curve during early morning hours and a peak in the evening. The area under a (daily) chronological load curve measures the total energy consumption during the day, evaluated by $\int_0^{24} (kW)\,dt$, expressed in kilowatt-hour (kWh) terms. From the load curve is derived *the load duration curve* (LDC), by rearranging all the loads of the chronological curve in the order of descending magnitude; thus it plots the load against the number of hours (or duration, θ) during the day for which it occurs. A typical LDC also is shown in Fig. 2. Note that the areas under the chronological curve and the corresponding LDC are equal. Annual LDC is generated from the aggregation of all the daily load curves, and is used for planning purposes, which we will consider later on.

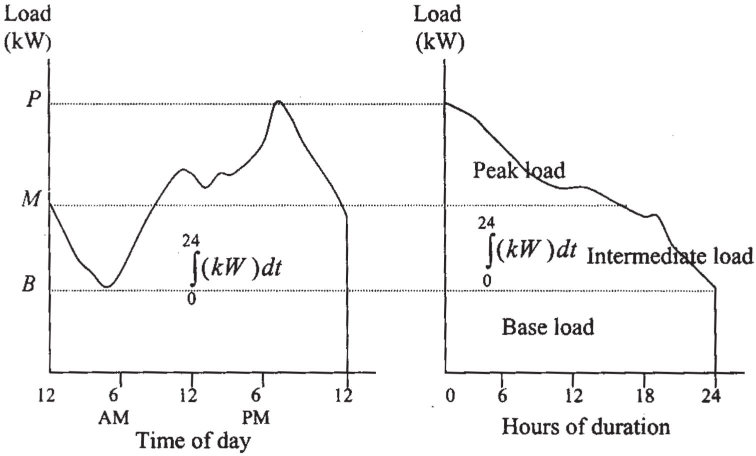

Fig. 2: Chronological load curve and the derived load duration curve

The cost of supplying electricity to consumers may be divided into demand and energy costs, [9] comparable to the common industrial classification of fixed and variable costs. Demand (or load or capacity) costs are the capacity related costs for generation, transmission and distribution, and vary with the quantity of plant and equipment and the associated investment. Energy (or unit or output) costs are those which vary directly with the quantity of units (kilowatt-hours) generated. They are largely made up of the costs of fuel, fuel handling and labour. The β in our earlier discussion roughly represents the demand costs and b, the energy costs. Thus determination of b is straightforward, once number of units of energy generated is known. On the other hand, β is determined on the basis of pro-rating of the annuitised cost of installing and maintaining the plant over its useful life. Thus, if the basic cycle is one year and the life of a plant of 100 kW capacity is 25 years, then β will be equal to 1/100th of the annuity sufficient to maintain and replace the plant after 25 years.[10]

One of the technical characteristics of electric utilities is that they operate under common cost conditions; electricity supply involves joint utilisation of all or most of the facilities. Under such conditions, only a part of the total supply costs if possible can be identified as applicable entirely to a certain customer class. The substantial portion of the costs thus left unaccountable for must be allocated to different consumer classes in proportion of their contribution to the relevant cost causation factors, such as peak load.

Thus the peak load problem was at the heart of Dr, John Hopkinson's 1892 proposal of Maximum-demand tariffs, the famous two-part tariff, devised on the assumption that the fixed costs attributable to a consumer are proportional to his peak kilowatt load and variable costs, to kilowatt-hour consumption. Designing a scientific method for the allocation of demand costs, along with the peak load pricing problems, has concerned the electric utilities at least since the 1920s, and a large number of different methods[11] developed have vied with one another for general acceptance without much success. One of the few common methods (peak responsibility method) follows the traditional peak load pricing logic and allocates the entire demand costs in proportion to the contribution of each class to peak load, sparing the off-peak consumers. The distributional concerns of such 'discriminatory' [12] pricing involved in demand cost allocation have led to an average and excess demand method. As we know, base-load capacity is continuously operated, and used by all the consumer classes in both peak and off-peak periods. That is, off-peak service also requires *some* capacity, and hence the corresponding demand costs are allocated to off-peak consumers in proportion to their average demands; and the peak period (or excess) demand costs are dealt with in accordance with the peak responsibility method.

An important concept that has an overwhelming bearing on common cost allocation is load factor (LF), defined as the ratio of the average load (in kilowatts) to the peak or maximum load during a given period (say, a year). If we disregard reserve margin, assuming capacity as equal to peak load, then the ratio (LF) yields capacity factor (CF), a measure of capacity utilisation, rather than demand variability as implied in the former. Plant load factor (PLF) defined in the same vein measures capacity utilisation of a given plant. It goes without saying that cost per unit (kilowatt-hour) generated is inversely related to capacity utilisation and thus to LF. That is, at cent per cent LF, installed capacity is put to the best possible use, and the maximum possible amount of energy is produced during a given period; capacity cost distributed over this maximum amount of energy would be a minimum in this respect. On the other hand, at a low LF, the same capacity cost is spread over a less number of units generated, yielding higher unit cost. Thus a poor LF implies cost inefficiency also. It is this techno-economic characteristic that we make use of in our model; that is, the capacity cost is distributed on an average basis according to the PLF.

Given this background, let us now turn to the optimum planning of plant mix. With reference to Fig. 2, suppose that the peak demand on the system is P kW. If there is only one generating plant in the station, with a capacity equal to the peak load, then the prime mover and generator will be running under-loaded most of the time, thus rendering the operation uneconomical. A better method is to divide the load into three parts, referred to as base load (B), intermediate load (M) and peak load (P), as shown in Fig. 2, each being supplied from separate plants. Thus the base load plant, with a capacity of B kW, is run continuously for all the time (i.e., on full load), and the peak load plant, with a capacity of $P - M$ kW, only for a short time. Between these two is the duration of operation of the intermediate load plant, with a capacity of $M - B$ kW.

The most economical operation of an electric utility requires that the plant having the minimum operating cost be used to meet the base load, e.g., run-of-river-flow-type (or reservoir-type) hydroelectric plant or nuclear power plant, and that the plant with the highest operating cost, to supply the peak load, e.g., gas turbine plant or pumped-hydro plant. The logic is simple - the total running cost will be a minimum, if the plants are operated inversely to their running costs; remember the base load plants are run for the longest time (with full load, i.e., at cent per cent PLF) and the peak load plants for the shortest time (at lower PLF). Evidently, the total operating cost will be a minimum, when a low-running-cost plant (rather than a high-cost one) is used as the base load plant. At the same time, optimum planning also requires that the capacity cost of the base load plant be the highest and that of the peak load plant, the lowest, as it is so in practice: nuclear or hydropower plants are much costlier to install than the gas turbines. The cost minimisation in this respect evidently follows from the inverse cost-PLF relationship, explained above. It should also be pointed out here that in actual practice, hydro- or diesel-power plant is used as peak load plant, since these sets are quick to respond to load variations, as the control required is only for the prime mover, whereas in steam-turbine plant, control is needed for the turbines as well as for the boilers.

The significance of PLF in determining the most economical plant scheduling, that has much to do with the structuring of optimum tariffing, has, however, not so far been recognised in peak load pricing literature. And precisely this technical inadequacy has been the source of the error in the usual peak load pricing result, which supplies to the off-peakers free of capacity cost. Once the capacity utilisation factor during a particular period is accounted for in an optimum tariff structuring, then the corresponding portion of the capacity cost is automatically attributed to that period. This we show below.

4. The Modified Peak Load Pricing Model

As usual, the problem is to maximise the net social welfare, given by

$$W = \sum_t \int_0^{D_t} \theta_t P_t(y_t)\,dy_t - C(D, Q), \qquad \ldots.\ (4)$$

where Dt is demand in period t ($t = 1, \ldots, T$), $P_t(D_t)$ is the inverse demand function, assumed to be periodically independent,[13] θ_t denotes the duration of period t, and $C(D, Q)$ represents total cost as a function of demand and capacity during the given cycle. We follow the heterogeneous technology specification of Crew and Kleindorfer (1975): there are m different plants ($j = 1, \ldots, m$), having constant operating cost

b_j (per kilowatt-hour per period)and capacity cost β_j (per kilowatt per cycle, say, year); therefore the total cost is:

$$C = \sum_t \sum_j \theta_t b_j q_{jt} + \sum_j \beta_j Q_j \,, \qquad \text{.... (5)}$$

where q_{jt} is power output (in kW)[14] of plant j in period t and Q_j, capacity of plant j (in kW).

This maximisation is subject to:

$$\sum_j q_{jt} = D_t \,, \; \forall\, t \qquad \text{(dual variables } \lambda_t\text{)}, \qquad \text{.... (6)}$$

$$k_{jt} Q_j - q_{jt} = 0, \quad \forall j, t, \quad \text{(dual variables } \gamma_{jt}\text{)}, \qquad \text{.... (7)}$$

$$D_t \geq 0, \quad q_{jt} \geq 0, \quad Q_j \geq 0, \quad \forall\, j, t, \qquad \text{.... (8)}$$

where k_{jt} is the corresponding PLF. The first constraint (6) requires that demand be met in each period, and the second (7) that output of each plant in each period be equal to the corresponding capacity *that is actually utilised*. Implied in the latter is the condition that output should not exceed capacity; but it qualifies the usual capacity constraint in terms of capacity utilisation, and thus rules out the possibility of off-peak output being independent of capacity, as explicitly specified so far in the literature. And this is our basic point of departure from the tradition.

Now the Lagrangian (L) from (4) - (8) is:

$$L = W + \sum_t \lambda_t \left(\sum_j q_{jt} - D_t \right) + \sum_t \sum_j \gamma_{jt} \left(k_{jt} Q_j - q_{jt} \right) \qquad \text{.... (9)}$$

Assuming strictly positive output (or $Dt > 0$), at the optimal solution, the Kuhn-Tucker conditions for the above maximisation problem are:

$$\theta_t P_t (D_t) = \lambda_t, \ \forall \ t; \qquad \text{.... (10)}$$

$$\lambda_t - \theta_t b_j - \gamma_{jt} \le 0, \quad q_{jt} \ge 0, \quad q_{jt}(\lambda_t - \theta_t b_j - \gamma_{jt}) = 0; \forall \ j, t; \qquad \text{.... (11)}$$

$$\sum_t \gamma_{jt} k_{jt} - \beta_j \le 0, \ Q_j \ge 0, \ Q_j \left(\sum_t \gamma_{jt} k_{jt} - \beta_j\right) = 0, \forall j; \qquad \text{...(12)}$$

$$\gamma_{jt} \ge 0, \quad \gamma_{jt}(k_{jt} Q_j - q_{jt}) = 0, \ \forall \ j, t. \qquad \text{....(13)}$$

Also note that with independent demands, L (in 9) is strictly concave, and the above conditions, (10) - (13), are necessary and sufficient for maximisation.

Now, let us find the optimum prices for the two periods, peak and off-peak (t = peak, p; off-peak, o), first in the case of the traditional framework of homogeneous technology (i.e., only one plant; $j = 1$). From (10) and (11), we get

$$\theta_t P_t = \theta_t b_1 + \gamma_{1t}, \ t = p, o. \qquad \text{.... (14)}$$

Consideration of (7) along with (13) requires that $\gamma_{1t} > 0$ *always*; i.e., the (modified) capacity constraint is *always* binding, since, as we have already discussed, some capacity is utilised in the base period also. Hence, we have to substitute in (14) for the shadow price from (12) for $Q_1 > 0$. Since this capacity is used in both the periods, though in different degrees depending on k_{1t} (such that $k_{1o}Q_1 = q_{1o} = D_o < k_{1p}Q_1 = q_{1p} = D_p$ at the optimum), the corresponding capacity cost is to be distributed over the whole range of output of both the periods and then apportioned to each period in proportion to its significance. The first task (of capacity cost distribution over total output) may better be captured by dividing the unit capacity cost, β_1, by the sum of the capacity utilisation factors, k_{1t}, of the two periods.[15] Consideration of (12) for $Q_1 > 0$ then lends enough sense to equate this with the shadow price of the modified capacity constraint (7). [16] That is,

$$\gamma_{1t} = \frac{\beta_1}{\sum_{t=p,o} k_{1t}} \equiv \frac{\beta_1}{k_{1\bullet}} \equiv \beta_1' \qquad \text{.... (15)}$$

where $k_{1\bullet}$ is the sum of k_{1t} over peak and off-peak periods. Thus we have the two optimum prices (per kilowatt-hour) as:

for peak period: $$P_p = b_1 + \frac{\beta_1'}{\theta_p}, \text{ and} \qquad \text{.... (16)}$$

for off-peak period: $$P_o = b_1 + \frac{\beta_1'}{\theta_o}. \qquad \text{.... (17)}$$

Since the peak time duration (θ_p) is much shorter (though k_{1p} is the maximum), the unit capacity cost contribution to peak period price (per kilowatt-hour) will be much higher, and hence the peak period price will be much greater than the off-peak price, as required. Also note, with reference to (16) and (17), that the sales revenue from the output of plant j during time t, is given by $P_t\theta_t q_{jt} = b_j\theta_t q_{jt} + \alpha_{jt}\beta_j Q_j$, where $\alpha_{jt} = k_{jt}/k_{j\bullet} = q_{jt}/q_{j\bullet}$ is the plant's output share during time t (where $q_{j\bullet} = \sum_t q_{jt}$), such that the total revenue from any plant j during any time t covers the corresponding total (energy and capacity) costs.

Thus we find that both the on-peakers and the off-peakers contribute to capacity cost recovery, in inverse proportion to their load duration. It should be stressed that our result contradicts all the earlier studies in the homogeneous technology framework, which have toed the tradition of sparing the off-peakers from capacity charges. Also note that the load management strategy of the peak load pricing dominates here over the minimum cost allocation principle associated with PLF. Again, this capacity cost allocation to the off-peakers does not follow the usual marginal cost principle, but just corresponds to a fairness principle in the sense of Weintraub (1970) in accounting for capacity use that occurs in both the periods, though the additional capacity is occasioned by only the peak users. This result is unique in the homogeneous technology case only. In the diverse technology framework, based on economical load scheduling, it is the marginal cost principle itself that matters; that is, by accounting for additional capacity in both peak and base load, as explained earlier. We now turn to this case, with $j = 2$ plants.

Suppose that plant 1 (say, hydropower plant) has lower marginal operating (and higher marginal capacity) costs than plant 2 (say, gas turbine). Optimal load scheduling requires that plant 1 be run as base load plant, and plant 2 to meet peak load. Evidently, the off-peak price is related to the costs of plant 1 and peak price to that of plant 2, in line with the marginal cost principle. Since plant 1 is used continuously in both peak and off-peak periods, we have $\gamma_{1t} > 0, \; t = o, p,$ such that

$$k_{1o}Q_1 = q_{1o} = k_{1p}Q_1 = q_{1p} = D_o > 0; \qquad \text{…. (18)}$$

that is, plant 1 continues to supply $q_{1p} = D_o$ units in the peak period also. On the other hand, plant 2 is used only in peak period, such that $\gamma_{2o} = 0$, $k_{2\bullet} = k_{2p}$, and meets the additional peak requirements:

$$k_{2p}Q_2 = q_{2p} = D_p - D_o > 0. \qquad \text{.... (19)}$$

Then, we have:

$$\text{for off-peak period:} \quad P_o = b_1 + \frac{\beta_1'}{\theta_o}, \text{ and} \qquad \text{.... (20)}$$

$$\text{for peak period:} \quad P_p = b_2 + \frac{\beta_2}{k_{2p}\theta_p} \equiv b_2 + \frac{\beta_2'}{\theta_p} \qquad \text{.... (21)}$$

Remember $b_1 < b_2$, but $\beta_1 > \beta_2$. Peak duration is much shorter than off-peak duration; while the peak load plant normally operates at low load factor, the base load plant is run at full capacity, such that $k_{1o} = k_{1p} > k_{2p}$. Thus (20) and (21) appear incomparable. However, we can rewrite (20) in terms of capacity and running cost savings in the context of optimal plant mix *a la* Crew and Kleindorfer (1971) and Wenders (1976), and prove that the off-peak price is lower than the peak price in the given operating regime, as required.

From (10) and (11), we get for $j = 1$ and $t = o$,

$$\theta_o P_o = \theta_o b_1 + \gamma_{1o}; \qquad \text{.... (22)}$$

from (10), (11) and (12), and noting that $k_{1o} = k_{1p}$,

$$\gamma_{1o} = \beta_1 / k_{1o} - (P_p - b_1)\theta_p. \qquad \text{.... (23)}$$

Therefore, we have [17]

$$P_o = b_1\left(1+\frac{\theta_p}{\theta_o}\right)+\frac{\beta_1}{k_{1o}\theta_o}-\left(b_2+\frac{\beta_2}{k_{2p}\theta_p}\right)\frac{\theta_p}{\theta_o} \quad . \qquad \text{.... (24)}$$

The logic for this is as follows. Given the operating regime in (18) and (19), the cost of meeting an additional unit of load in off-peak period can be minimised by increasing plant 1 capacity by one unit, involving a marginal cost of $b_1\theta_o + \beta_1/k_{1o}$ and reducing plant 2 capacity by one unit yielding a marginal cost saving equal to $b_2\theta_p + \beta_2/k_{2p}$, the cost that would have been incurred, had plant 2 been used instead (which in turn is equal to $P_p\theta_p$); since the additional unit of plant 1 is used in peak period also, it involves an extra cost of a fraction of its running cost, ($b_1\theta_p$). Hence the expression (24).

Now let us prove that this price (24) lies below the peak load price (21) in the given operating regime. Since plant 1 is used at full load in both the periods, its marginal cost (mc_1) of supplying one unit is: $b_1(\theta_o + \theta_p) + \beta_1/k_{1o}$ (from (11) - (12) and noting $\gamma_{jt} > 0$ and $k_{jo} = k_{jp}$). Optimal plant mix requires that this be less than the corresponding marginal cost of plant 2 (mc_2), given by $b_2(\theta_o + \theta_p) + \beta_2/k_{2p}$, since otherwise plant 1 would not be required at all. This inequality ($mc_1 < mc_2$) yields the required bounds: $b_1 < P_o < b_2 < P_p$ at the optimum. At the same time note that since plant 2 is used to meet the peak load, it must be cheaper than plant 1 to do so; that is, $mc_{2p} = b_2\theta_p + \beta_2/k_{2p} < mc_{1p} = b_1\theta_p + \beta_1/k_{1p}$; ($k_{jo} = 0$). Thus we have the following bounds at the optimum in general: $b_1 < P_o < b_2 < P_p < mc_{1p}/\theta_p$.

An important property of our pricing model is that it easily lends itself to generalisation in practical application. With reference to (20) and (21), note that it is the unit (energy and capacity) costs of the marginal plant that go into the rate structure - plant 1 is used at the margin in the off-peak period and plant 2 in the peak period, though the former, being the base load plant, also is in use during the peak period. This technical characteristic helps us generalise the pricing rule for a scenario of diverse technology ($j = 1, \ldots, m$), with multiple periods ($t = 1, \ldots, T$) as:

$$P_t = b_j + \frac{\beta_j}{k_{j\bullet}\theta_t} \equiv b_j + \frac{\beta'_j}{\theta_t}, \qquad \ldots. (25)$$

where $\beta'_j \equiv \beta_j / k_{j\bullet}$, and $k_{j\bullet} \equiv \sum_t k_{jt}$, the parameters are those of the marginal plant in use at time t. Remember the base load plant, ($j = 1$), is continuously run in all the periods, the medium load plants, in peak and intermediate periods only, and the peak load plant, ($j = m$), in peak period only, such that $k_{m\bullet} = k_{mp}$.

In the next section, we give an illustrative application of this pricing rule to the Kerala power system.

5. An Illustrative Application

Kerala power system,[18] like most of the other power systems in India, remains a less developed one, plagued by a host of very obvious techno-economic dysfunctionings, primarily on account of an absence of a development-focussed perspective planning (Pillai 2002). Capacity deficiency has been felt pinching since the early 1980s, ushering in an era of restrictions on new connections and load shedding. The system now manages to function thanks to large-scale energy import; for example, in 1999-2000, import constituted 43.6 per cent of the total

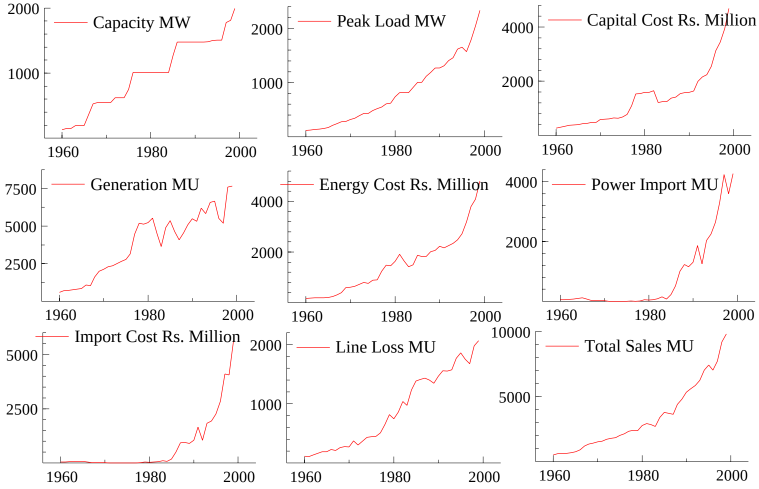

Fig. 3: The relevant techno-economic variables of the Kerala power system over the last 4 decades

energy sales in Kerala, and the corresponding (import) cost, 38 per cent of the total expenditure. Though the underdevelopment could seriously impair the otherwise smooth causal relationship among the techno-economic variables of the system (for example, between capital cost and peak load), we proceed to use the available data, since our aim is only an illustrative application. Table 1 reports the decadal mean level and growth[19] of the techno-economic variables of the power system relevant to us during the last four decades (1960-61 to 1999-2000) and Fig. 3 plots them.

Methodology

It should be noted that the pricing structure we are interested in essentially consists in the long run marginal cost, which includes short run marginal energy cost and marginal capital cost (Boiteaux and Stasi 1964). [20] The former is obtained as 'variable cost' from marginal generating and purchasing costs, adjusted for loss of energy in the transmission and distribution (T & D) processes, and the latter is the cost of additional capacity to meet one kW increase in demand. As we know, in theory, marginal cost is associated with the plant-unit at margin; but in actual practice, exact identification of the marginal plant-unit is very difficult, if not impossible; since an interconnected power system has a variety of sources of output to meet the demand on it (including power purchases from different sellers), the 'marginal' plant-unit would vary from time to time according to load fluctuations. This renders the marginal-plant costing method, especially in the forward-looking context, ineffectual. Hence an alternative method is followed in practice, viz., taking a weighted average of all the *ex post* costs associated with different sources of marginal output to the system.

Here we identify in general two sources of power to the system: own generation and import. The former may further be divided into thermal and hydro. Since we do not have in our case separate, technology-specific costs data, we consider the two aggregate sources only. Thus total operating cost is taken as a function of energy generated ('generation') and capacity; and power purchase cost, as a function of energy imported ('import'). These would yield estimates of marginal generation (operating) and import costs from the time series data we use. Similarly, line loss is cast as a function of total sales for the marginal adjustment factor of T & D loss. Once these estimates are available, the marginal running cost is found as:

$$MC_e = q^{-1}\left(q_g MC_g + q_i MC_i\right)\left(1 + L\right), \qquad \text{.... (26)}$$

where MC_e = marginal energy cost,

q_j = quantity of energy from the *j*th source; *j* = generation (*g*) and import (*i*),

MC_j = marginal cost of energy from the jth source; j = generation (g) and import (i),

q = total energy available from the two sources ($q = q_g + q_i$), and

L = marginal loss factor.

Marginal capacity cost is that incurred in setting up an additional kilowatt (kW) of capacity to meet an additional demand. Installed capacity is generally planned to contain the expected peak demand, adjusted for a certain reserve margin to ensure reliability in meeting contingencies. Thus with a 10 per cent reserve margin, installed capacity is planned at 1.1 times the expected peak demand. It is true, as we have already stated, that additional plants are required to meet not only the rising peak load but also the expanding base load. However, we assume that the total increase in demand is proportional to that in peak demand, and this facilitates defining a functional relationship between capacity cost and peak load. The possibility of power purchase weakening this causal relationship is ignored here. A 'first approximation' to capacity cost is in terms of 'the fixed costs of operating existing equipment' (DeSalvia 1969). Fixed costs in our case include depreciation, as the costs incurred in the utilisation of the existing capacity, and interest payments and net surplus, as the costs required for obtaining this capacity. The marginal capacity cost thus obtained is then apportioned[21] between peak and off-peak periods according to the spread over their length, as our pricing rule (25) suggests.

For the Kerala power system, annual data on total expenditure are available under the heads of i) generation, ii) repairs and maintenance, iii) employee costs, iv) administration and general expenses, v) energy purchase, vi) depreciation, and vii) interest charges. The last two, along with net surplus, constitute our fixed costs category, and the remaining are taken to represent our variable costs.[22] These, excluding purchase cost, are put in the operating cost category. The costs data are considered for analysis at constant 1993-94 prices. The range of study spans four decades, from 1960-61 to 1999-2000.

Cointegration Analysis

The usual application of regression technique to time series involves problems of spuriousness from possible non-stationarity in the series; hence we proceed with a cointegration analysis to identify (static) long-run relationship, if any, in our functional specifications. Table 2 reports the results of the (Augmented) Dickey-Fuller unit root tests applied to the 9 variables under consideration; optimal number of lag is selected according as the model satisfies adequacy tests (and yields white noise residuals). We find that all the variables, except capital cost and probably peak load too, are integrated of unit order, that is, I(1); and the other two, I(2). It should be noted that presence of structural change can make a stationary variable appear non-stationary; and the plots in Fig. 1 show that all the variables have multiple breaks in their time profile. We however do not pursue this aspect further, considering time constraints, though we could go on testing for unit root in the presence of structural changes.[23]

Assuming that all the variables, except capital cost and peak load, are I(1), and the other two, I(2), we now proceed to find if the functions we have specified for the variables define any stationary long-run relationship, that is, if they are cointegrated. Consider the autoregressive-distributed lag (ADL) model

$$a(L)y_t = b(L)x_t + \varepsilon_t \, , \qquad \ldots (27)$$

where L is the lag operator such that $Lx_t = x_{t-1}$, and $b(L) = \sum_{i=0}^{n} b_i L^i$ is a scalar polynomial in L of order n, the longest lag length. In the long-run, when $L = 1$, $a(1)$ [as well as b(1)] denotes the sum of the coefficients. If $a(1) \neq 0$, and (y_t, x_t) are jointly weakly stationary, then the long run average solution to (27) is:

$$E\left(y_t - \frac{b(1)}{a(1)} x_t\right) = E(y_t - \beta x_t) = 0. \qquad \ldots. \quad (28)$$

Obviously, it is required that there be no unit root in the polynomial *a(L)* for (28) to be well-defined, and that $b(1) \neq 0$, to be non-trivial. When $a(1) \neq 0$, $b(1) \neq 0$, and y_t and x_t are both I(1), then they are said to be cointegrated, if $(y_t - \beta x_t)$ is I(0).[24] Also note that in the case of the capital cost model, capital cost and peak load, taken to be I(2), are said to be cointegrated if their linear combination $(y_t - \beta x_t)$ is I(1) [or even I(0)], which is well defined when $a(1) \neq 0$, and $b(1) \neq 0$, as expected.

The results of cointegration tests on our model specifications are given in Tables 3 - 6. The static long-run solutions are reported in Table 3. In the operating cost model, the estimated coefficient of generation has a wrong sign, but is insignificant. In view of the high correlation between generation and capacity (0.935), we consider another model with generation only to determine operating cost; and the estimated coefficient is found to behave well. It is so in the capital and energy import cost models also, but not in the line loss model. However, an analysis of the lag structure (Table 4) and the roots of the lag polynomial (Table 5) of each variable in these models show that the variables are not cointegrated. The null of $a(1) = 0$ can be rejected (so that the long-run solution exists) only in the energy import cost model and that of $b(1) = 0$, (so that the solution is non-trivial), only for peak load and energy purchase. However, we find that some of the roots in the lag polynomial of these (and other) variables are not below unity, (so that the systems remain non-stationary), suggesting non-cointegrability.[25] Further proof comes from the results (Table 6) of the Johansen and Juselius (J-J) cointegration tests (Johansen 1988; Johansen and Juselius 1990), where we use the maximum eigenvalue and trace statistics with small sample correction (Reimers 1992). Starting with the null of no cointegration ($r = 0$) among the variables in a model, we find that both the corrected maximum eigenvalue and trace statistics are well below the respective 95 per cent critical values, confirming non-rejection of the null of no cointegration at 5 per cent significance level in all but one model. Note that for the capital cost model, the null of no cointegrating relationship is rejected at 1 per cent level; hence we go on to see if there is one well-defined cointegrating vector ($r = 1$) out of the possible two; and this null also gets rejected at 5 per cent level, suggesting two cointegrating vectors.[26] But note that this contradicts the earlier result for the model that $a(1) = 0$.

Increment Quotient Method

Thus all of our models for marginal energy cost estimation fail to elicit the expected long-run relationship out of the given data. Though the capital cost model may be taken as valid, based on the J - J test result, we cannot proceed with a regression estimation of marginal capital cost independently of marginal energy cost, for which a regression is not valid. Hence here we use a simple alternative for estimating marginal costs based on the relevant time series data. While the statistical estimator of marginal cost is given by the differential quotient, dC_t / dq_t, the estimation of which is fraught with non-stationarity problems, we use an analogous discrete difference quotient, $\Delta C_t / \Delta q_t$, simple but involving no statistical problems. We can have a marginal estimate for a given period in terms of the ratio of the respective increments during that period, provided there is stable trend in the time series of the concerned variables. Table 7 reports the marginal costs thus estimated for 1999-2000 over the first year of the last four decades both at constant 1993-94 prices and at current prices. Thus, compared with 1960-61, the operating cost in 1999-2000 increased by Rs. 4652.7million at constant prices against an increase in generation of 7064.6 million units (MU; 1 unit = 1 kWh) during the same period, giving an estimate of the marginal operating cost of Rs. 0.66 per unit. Similarly, fixed costs at constant prices increased during the same period by Rs. 4408.5 million against an increment of 2060.7 megawatt (MW) in peak load, yielding an estimate of the marginal capital cost of Rs. 2139.3 per kW per annum. An estimate of marginal loss factor of 21 per cent is obtained from the increments in line loss and energy sales respectively of 1955 MU and 9307.3 MU during the period. Similar estimates for other periods, with the first year of each decade taken as the base period over which the increment is measured for 1999-2000, are also given in Table 7 for comparison. An estimate based on increments over a nearer base period would capture the recent trends in the variables, whereas one with a distant base would represent the steady, long-run trend.

The estimates of the marginal operating and energy import costs are now fed into (26) to obtain an estimate of marginal energy (or running) cost, adjusted with the marginal loss factor. This, over the base year of 1960-61, comes out to be Rs. 1.1 per unit. An alternative estimate also is obtained by ignoring the marginal loss factor and dividing the total costs obtained from (26) by total sales; the two estimates hardly differ. Remember this estimate represents the *b* in our pricing rule (25).

Next, the marginal capital cost we have already estimated must be apportioned between peak and off-peak periods. Here we can have different alternative estimates according to the definition of the peak period duration. Peak load on the Kerala power system is in general estimated as an average of load over a half an hour period during the late evening peak. This gives a peak period duration of 182.5 hours a year. However, demand is generally found to remain higher over a fairly long period in the late evening and after, often on an average 3 hours, giving a peak period duration of 1095 hours a year. We consider both these alternatives of 'short' and 'long' duration.

The peak load factor, as we have already seen, is unity ($k_p = 1$, suppressing j, the plant subscript), and the off-peak load factor, with the 'short' peak duration, in 1999-2000 is estimated at 61.8 per cent, giving $k_\bullet = 1.62$. This, along with the marginal capital cost estimate over 1960-61, yields β' = Rs. 1322.5 per kW per year as per (25). Distributing this over the peak and off-peak duration, we get a peak period capital charge of Rs. 7.25/kWh and an off-peak capital charge of Rs. 0.15/kWh. The sum of the marginal energy and capital costs yields the peak load prices: a peak price of Rs. 8.33/kWh and an off-peak price of Rs. 1.24/kWh. If we ignore peak-off-peak differential spread, the uniform capital charge, adjusted for total capital utilisation $k_\bullet = 1.62$, would be Rs. 0.15/kWh, and the uniform price, Rs. 1.24/kWh.[27] Remember this peak price is applicable to a very short period of half an hour only. Hence we consider the 'long' alternative, in which case, assuming for simplicity the same peak load continued for 3 hours (as we do not have precise data), the total load factor is 1.51, and the peak and off-peak capital charges are respectively Rs. 1.29/kWh and Rs. 0.19/kWh. These give a peak price of Rs. 2.38/kWh and an off-peak price of Rs. 1.27/kWh. The uniform price is Rs. 1.25/kWh. We have estimated all these prices using our different estimates of marginal costs, based on different base periods. Note that the recent base period marginal cost estimates lead to higher prices. In addition to these estimates at constant 1993-94 prices, we have also calculated prices including current inflation effect (Table 7).

6. Conclusion

The present paper has attempted at a contribution to peak load pricing, in both theory and application. The general result from the traditional theory that charges the off-peak consumers marginal operating costs only and the on-peak users marginal operating plus marginal capacity costs, since it is the on-peakers who press against capacity has already been called into question. It has also been shown that the equity norms are violated in the traditional peak load pricing, whereby off-peak users pay no capacity charges, but are supplied output out of the capacity, 'bought/hired' by the on-peakers. Theoretical attempts at modification have proved that the traditional conclusion holds only for homogeneous plant capacity (e.g., in one plant case), and in economic loading of two or more plants, the off peak price also includes a part of capacity costs. However, this appears in terms of an expression for capacity and running cost savings in line with the logic of optimum plant mix, without yielding a practical rate structure in a format like that of peak price. Our methodology does yield such a one.

The present paper also stresses the role of peak load pricing in load management especially in the context of electricity supply: the peak price must *always* be greater than the off-peak one in order to improve capacity utilisation at a desirable uniform level through 'peak clipping' and 'valley filling'; at the same time it should be so structured as to ensure equity concerns by apportioning capacity costs, (which are common to all periods), to both the peak *and* off-peak users by their importance relative to total use.

It has been traditionally assumed that whenever a unit of capacity is installed at a cost, it becomes available for demand in *all* periods; off-peak demand also is met from this capacity; yet this relationship has not been explicitly incorporated into the cost equation. And thus the off-peak price has come out without the capacity cost component! This paper, however, shows that if the off-peak period output is explicitly expressed in terms of capacity utilisation of that period, the result will be an off-peak price including a fraction of the capacity cost in proportion to its significance relative to total utilisation. This would appear as a general case, irrespective of the nature of generation technology, that is, even when there is only one plant.

An important property of our pricing model is that it easily lends itself to generalisation in practical application. We also give an illustration by estimating marginal costs and peak load prices using time series data on the Kerala power system. Where the data are incapable of yielding the required statistically determined long-run relationship among the variables under study, we propose a simple and viable method of using discrete ratio of increments as a proxy for an econometrically determined marginal value. A problem with this method is the choice of a suitable base year over which the increments are measured. We feel that a recent base period that can represent the latest trends in the variables might do well; for a hydro-dominant power system, like Kerala's, a period of 10 years, roughly equal to the construction period of a hydropower station, might be ideal. It should also be noted here that we could not proceed with the more usual econometric method of estimating marginal costs based on cross-section data due to non-availability of such data.

Another important merit of our method is its amenability to customer-group-wise tariffs structuring. The marginal capital cost may be apportioned, following the average method of common cost allocation, among the different customer classes. In our application we have left out this exercise, as customer-class-specific data on diversity factor, that captures class-specific contribution to simultaneous incidence of peak load, are not readily available.

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Notes

1. "I frame no hypotheses."

2. It is in fact the peak load problem in electricity supply that motivated much of the early work on the peak load pricing theory (Crew and Kleindorfer 1976).

3. There are several options open for load management. On the consumer side, adoption of energy efficient end-use appliances has become a promising practice of potential benefits; the various options here are: i) energy-efficient motors, ii) variable speed drives, iii) replacing incandescent bulbs with fluorescent or compact fluorescent lamps, iv) replacing magnetic ballasts with electronic ballasts, v) replacing water heaters with solar water heaters, and so on. For the utility, the load management techniques include direct (mechanical) controls on end-use equipment, and pricing; the latter working through interruptible tariffs and time-differentiated (peak-load) tariffs. Under interruptible or load-limited tariff, consumers subscribe to a certain maximum demand and are automatically and temporarily disconnected by a small circuit breaker (in the house) if they exceed it; they are thus compelled to turn off some appliances and reset the breaker for further supply.

4. Peak load or time of day (TOD) electricity rates have been widely used in Europe for several decades to reflect peak-load cost variations. In particular, *Electricité de France* (EDF) has been responsible for innovations in implementing TOD pricing and load management techniques. French tariffs departed from the traditional pattern of Hopkinson rates common in the USA and the UK some years after the nationalisation of the electricity industry in 1946, with the introduction (in 1958) of *le tarif vert* (the green tariff), that applied to high voltage (HV) customers. At present in most of the European countries, where thermal generation is dominant, the HV tariff structure reflects the significance of seasonal and TOD variations in demand and costs

of the marginal plants operated on specific load scheduling. In the Scandinavian countries with substantial hydel generation, seasonal variations in the availability of water also tends to influence the tariff level. The low voltage (LV), domestic, tariffs in general have been less complicated, using less complex metering. By contrast, the US regulatory bodies and utilities began to consider TOD rates only following the 1973-74 Arab oil embargo. It was in 1978 only that a provision was included in the Public Utilities Regulatory Policies Act (PURPA) of 1978, to charge TOD rates to each class of customers "unless such rates are not cost-effective with respect to each class" (PURPA, Section III d). Developing countries have started to introduce TOD tariffs at the HV and MV level only recently and that too in simpler terms primarily due to metering problems. In India some crude attempts at TOD tariffs have been made since the early eighties, but with only marginal effects of peak reduction and in some cases with revenue losses also (Parikh, *et al.*, 1994: 222). Non-availability of suitable meters has been the main problem in India.

5. It should be correctly (and rightly) pointed out here that the traditional theory looks forward in the right sense of marginal cost pricing to the cost of additional capacity required to satisfy the on-peakers, but ignores to look backward in the true sense of cost accounting to the actual cost of that part of capacity that the off-peakers use. Remember, the additional capacity thus 'bought' by the peakers in turn become available for the off-peakers also but at no cost, though fairness allocates a part of the capacity cost to them also in proportion to their importance in total use. It is in this context of equity considerations that the theory appears unfair.

6 It should be noted that this case refers to what is known as Steiner's 'firm peak case'. Steiner (1957) also considers what is called 'shifting peak case' that results as the pricing serves its purpose of load management. The low off-peak price induces and the high

peak price discourages consumption such that the loads tend to shift. At the resulting price-output points, capacity is fully utilised in both the periods, and the capacity cost is shared in proportion to the relative strength of the loads, thus determining different prices. This case is out of our consideration here.

7 Or it is the demand function in the Marshallian framework.

8 Note that with independent demands in a multi-product case, the total social welfare is simply the sum of the gross surplus (i.e., the integral or the area of the Marshallian triangle) of each of the *n* commodities.

9 A third category of customer costs, due to Henry Doherty, also is generally considered. These costs vary directly with the number of customers served, and include expenses on meter reading, billing, collection and consumer service, as well as a portion of the costs related to the primary and secondary distribution systems. These, along with demand costs, belong to fixed costs.

10 See Turvey (1969) for more details.

11 For more details see Davidson (1955); Doran, *et al*. (1973).

12 Steiner (1957) interpreted his peak load pricing results in terms of price discrimination; but Hirshleifer (1958) took issue with this and argued that the results could be more usefully interpreted in marginal cost pricing terms. Williamson (1974) backed Hirshleifer.

13 Note that the demands are periodically independent. We can, following Pressman (1970), specify interdependent demands, in which case we will have a line-integral formulation of gross surplus. Such a welfare function is well defined when certain 'integrability conditions' are satisfied (also see Crew and Kleindorfer 1979: 19 - 22), which is possible when demands in different periods are independent. Then the line integral specification of gross welfare becomes just the sum of simple integrals, as in (4).

14 Thus $\theta_t\, q_{jt}$ represents energy (in kilowatt-hour) of plant *j* during period *t*.

15 Remember $k_{1t} = q_{1t}\,/Q_1$, so that $\dfrac{\beta_1}{k_{1\bullet}} = \dfrac{\beta_1(q_{1o} + q_{1p})}{Q_1} = \beta'$, capacity cost per unit of output, equal to the *utilised* capacity.

16 Note that this implies that the shadow price of the modified capacity constraint (7) for any plant is the same across all time periods, $\gamma_{jo} = \gamma_{jp}$, but as (12) specifies, its attributed share varies across time according to the corresponding capacity utilisation.

17 Note that the expression is equivalent to that for off-peak price given by Crew and Kleidorfer (1971), assuming two equal duration periods and disregarding PLF terms.

18 Electrification in Kerala had its first hydro-electric generator of 200 kilowatt (kW) run in a private tea estate (the Kannan Devan Hill produce Company) at Munnar in the High Ranges in the then Travancore area in 1906. It took more than two decades after that for the Government to come to the scene by commissioning (on February 25, 1929) a 5 megawatt (MW) thermal station in Trivandrum exclusively for the royal and administrative uses. The first public sector power project, designed on a large scale for commercial uses, in Kerala came on line in March 1940 with the first unit of 5 MW of Pallivasal hydroelectric power station. The Kerala State Electricity Board (KSEB), the second SEB to be set up on 31. 03. 1957 under the Electricity (Supply) Act, 1948, with the prime objective of rationalisation of power development at the State level, inherited an installed capacity (IC) of 93.5 MW, that rose to 1993.6 MW by 1999-2000, as against an estimated requirement of nearly 3000 MW, as per the 14th Annual Power Survey. Kerala's was a purely hydropower system till recently, and hydro accounted for 88 per cent of the KSEB's own installed capacity in 1999-2000.

19 Most of the average annual growth rates in Table 1 are from the usual exponential growth models that satisfied all the model

adequacy tests and generated white noise residuals. The exceptions are those with the asterisks, derived from partial adjustment exponential growth models (i.e., including a lagged dependent variable) that behaved well in most of these cases (see Pillai 2001).

20 See, for an application of Boiteaux and Stasi (1964), DeSalvia (1969). Also see Chicchetti *et al*. (1977).

21 Note that the marginal capital cost may also be adjusted for per cent reserve margin, though in our exercise we ignore this aspect.

22 It should be recognised that labour (and its costs) in a pure/predominantly hydropower system cannot be a variable factor, and that the administration and general expenses include an element of fixed charges. The present categorisation strictly follows our definition of capital (fixed) cost and its residual.

23 See Perron (1989) for a modified DF unit root test in the presence of a known structural break, and Pillai (2001) for an application in the context of the Kerala power system. Chow tests using PcGive confirm presence of multiple breaks in almost all the time series we use here.

24 There is a vast literature on cointegration; for a review, also see Pillai (2001).

25 This is again confirmed as each of the models considered appear to have common factors (some of the roots of $a(L)$ coincide with roots of $b(L)$, resulting in autocorrelated residuals); the common factor Wald tests cannot reject in general. The results are not reported for space constraint.

26 We can also model capital cost along with capacity; but in our case, these two variables are of different order of integration.

27 The unadjusted uniform capital cost would be Rs. 0.24/kWh, and the corresponding price, Rs. 1.33/kWh in this case (i.e., with marginal cost over 1960-61).

Table 1: Some Techno-Economic Characteristics of the Kerala Power System

	Mean and Coefficient of Variation (%) during the				
	1960s	1970s	1980s	1990s	4 Decades
Unit Operating Cost	0.027	0.066	0.193	0.568	0.214
(C. V.)	(26.69)	(24.43)	(30.32)	(44.63)	117.01)
Unit Capital Cost	222.94	417.24	753.30	1934.95	832.11
(C. V.)	(9.42)	(43.74)	(9.94)	(41.07)	(93.67)
Unit Energy Import Cost	0.078	0.223	0.424	1.092	0.454
(C. V.)	(14.69)	(41.56)	(20.44)	(37.13)	(97.46)
Load Factor (%)	61.05	77.60	57.89	44.32	60.21
(C. V.)	(13.22)	(15.9)	(23.48)	(11.6)	(25.88)
Loss Factor (%)	17.88	14.28	22.88	19.69	18.68
(C. V.)	(14.7)	(12.79)	(20.57)	(8)	(22.69)
	Average Annual Growth Rates (%) during the				
	1960s	1970s	1980s	1990s	4 Decades*
Operating Cost	19.55	18.78	8.8	16.58	14.76
Capital Cost	5.26*	19.995	5.97	19.49	14.86
Energy Import Cost	–19.97*	19.68	47.84	25.46	37.94
Capacity	18.29	8.45	5.64	3.1	3.73
Peak Load	10.79	7.53	5.94	6.07	6.4
Generation	12.09	10.65	0.00014*	2.69	3.89
Power Import	– 25.48*	15.26	41.66	13.96	24.63
Notes: C.V.=	11.64	5.53	6.11	3.32*	6.64
Sales	10.62	10.25	7.03	6.88*	6.68

Notes:C.V. = Coefficient of variation; * = Long-run exponential growth rates derived from dynamic growth models (see end-note 19).
Unit operating cost is in Rs./kWh generated; unit capital cost in Rs./kW of peak load; Unit energy Import cost in Rs./kWh of energy purchased. All at current prices.
Load factor = Generation/Peak load;
Loss Factor = Energy lost in transit/Total available energy
Source: Estimations based on data from Kerala State Electricity Board Office, Thiruvananthapuram, Kerala

Table 2: Unit Root Tests

	No Constant/ Trend		With Constant		With Constant, Trend	
	Lag	ADF t - Value	Lag	ADF t - Value	Lag	ADF t - Value
1. Level						
Critical Value at 5 %		– 1.951		– 2.95		– 3.547
Capacity	0	2.84	0	– 0.563	1	– 3.707*
Peak Load	0	6.746	3	3.679	0	1.43
Capital Cost	5	2.275	5	2.085	5	1.042
Generation	2	1.764	2	– 1.125	0	– 2.905
Operating Cost	0	5.454	0	3.181	0	1.792
Energy Import	1	3.792	1	2.79	5	2.207
Import Cost	1	8.118	1	7.068	5	3.139
Line Loss	0	2.925	2	0.735	0	– 2.876
Total Sales	2	7.668	2	5.321	2	2.146
2. First Difference						
Critical Value at 5 %		– 1.951		– 2.953		– 3.551
Capacity	0	– 3.619**	0	– 4.408**	0	– 4.303**
Peak Load	4	1.679	4	0.616	0	– 3.755*
Capital Cost	0	–1.444	0	– 2.111	4	– 1.499
Generation	0	– 5.326**	0	– 5.672**	0	– 5.579**
Operating Cost	0	– 2.013*	0	– 2.97*	0	– 3.611*
Energy Import	0	– 5.929**	0	– 6.889**	4	– 4.49**
Import Cost	0	– 4.001**	0	– 4.855**	0	– 7.649**
Line Loss	0	– 4.715**	1	– 5.922**	0	– 6.168**
Total Sales	0	– 2.907**	1	– 5.08**	1	– 7.891**
3. Second Difference						
Critical Value at 5 %		– 1.952		– 2.956		– 3.556
Peak Load	3	– 4.556**	0	– 7.361**	3	– 4.88**
Capital Cost	0	– 7.905**	0	– 7.914**	0	– 7.987**
Operating Cost	0	– 7.604**	0	– 7.549**	0	– 7.525**

Note: **/* = Significant at 1% / 5 % level.

Table 3: Static Long-Run Models

Model	Independent Variables	Estimate	Standard Error	Wald test χ^2 -statistic
1. Operating Cost				9.503**
(3)	Intercept	89.1	380.7	
	Generation	- 0.00177	0.231	
	Capacity	1.175	0.824	
2. Operating Cost				7.793**
(4)	Intercept	- 125	333.8	
	Generation	0.305	0.109	
3. Capital Cost				3.977*
(5)	Intercept	33.78	305.4	
	Peak Load	1.766	0.886	
4. Energy Import Cost				242.49**
(10)	Intercept	- 0.094	1.66	
	Import	0.746	0.048	
5. Line Loss				0.0114
(2)	Intercept	1460	4360	
	Sales	- 0.131	1.227	

Notes: Figures in brackets are the number of lags
**/* = Significant at 1% / 5 % level.

Table 4: Analysis of Lag Structure

Model	Variables	Lag 0	1	2	3	4	5	6	7	8	9	10	Sum
1. (3)	Operating Cost	–1	1.2	– 0.19	0.23								0.245
	S. E.	0	0.192	0.316	0.31								0.166
	Generation	0.104	– 0.079	0.032	– 0.057								0.0004
	S. E.	0.054	0.07	0.092	0.086								0.057
	Capacity	7.19	–1[illegible]	13.5	– 9.9								–2.87
	S. E.	3.68	5.[illegible]	5.71	3.98								2.67
2. (4)	Operating Cost	–1	1.23	– 0.242	0.412	– 0.174							0.231
	S. E.	0	0.206	0.349	0.436	0.303							0.171
	Generation	0.037	0.01	– 0.083	– 0.008	– 0.027							– 0.07
	S. E.	0.055	0.076	0.099	0.122	0.093							0.072
3. (5)	Capital Cost	–1	1.23	– 0.288	– 0.041	0.255	– 0.434						– 0.273
	S. E.	0	0.209	0.339	0.341	0.42	0.299						0.186
	Peak Load	6.78	– 5.04	– 0.038	– 9.98	15.4	–2.35						4.82
	S. E.	8.22	8.72	8.63	9.04	12.2	12.3						2.38
4. (10)	Import Cost	–1	0.391	0.34	– 0.278	– 0.685	1.2	2.13	0.463	2.96	– 1.75	3.56	7.33
	S. E.	0	0.597	0.857	1.14	1.04	0.686	1.3	1.53	2.61	3.42	2.44	2.63
	Import	0.95	– 0.547	– 0.31	0.462	0.524	– 1.01	– 2.34	– 0.229	– 1.32	– 0.019	– 1.64	–5.47
	S. E.	0.074	0.595	0.829	1.03	1.07	0.861	1.32	1.45	1.77	2.22	1.67	2.21
5. (2)	Line Loss	– 1	0.909	0.065									– 0.026
	S. E.	0	0.186	0.193									0.078
	Sales	0.125	– 0.038	– 0.091									– 0.0035
	S. E.	0.053	0.085	0.062									0.023

Notes: Figures in brackets are the number of lags; lag structure of constant is not reported. S. E. = Standard Error

Table 5: Roots of the Lag Polynomials

Model	Variables	Roots					
1. (3)	Operating Cost	– 0.0004 ± 0.436i	1.205				
	Generation	– 0.121± 0.727i	0.998				
	Capacity	0.312 ± 0.991i	1.275				
2. (4)	Operating Cost	1.217	0.389	– 0.186 ± 0.576i			
	Generation	–1.685	–1.514	– 0.051± 0.531i			
3. (5)	Capital Cost	Failed to converge for root 5.					
	Peak Load	– 0.731± 1.045i	Failed to converge for root 3.				
4. (10)	Import Cost	1.389	–1.244	– 0.256 ± 0.975i	0.55 ± 0.761i	– 0.929 ± 0.832i	0.757 ± 0.951i
	Import	1.388	–1.158	– 0.349 ± 0.82i	0.503 ± 0.7i	– 0.762 ± 0.753i	0.782 ± 0.988i
5. (2)	Line Loss	0.975	– 0.067				
	Sales	1.016	– 0.714				

Note: Figures in brackets are the number of lags.

Table 6: Johansen and Juselius (JJ) Cointegration Analysis

1. Variables: Operating Cost, Generation, Capacity. Lag = 3.
   Eigenvalues: 0.34, 0.109, 0.099.

	Maximum Eigenvalue Test			Trace Test		
Ho:	H1:	Statistic+	95 % CV	H1:	Statistic+	95 % CV
r = 0	r = 1	11.65	21	r ≥ 1	17.8	29.7
r ≤ 1	r = 2	3.24	14.1	r ≥ 2	6.15	15.4
r ≤ 2	r = 3	2.91	3.8	r ≥ 3	2.91	3.8

2. Variables: Operating Cost, Generation. Lag = 4.
   Eigenvalues: 0.113, 0.077.

	Maximum Eigenvalue Test			Trace Test		
Ho:	H1:	Statistic+	95 % CV	H1:	Statistic+	95 % CV
r = 0	r = 1	3.36	14.1	r ≥ 1	5.62	15.4
r ≤ 1	r = 2	2.26	3.8	r ≥ 2	2.26	3.8

3. Variables: Capital Cost, Peak Load. Lag = 5.
   Eigenvalues: 0.572, 0.15.

	Maximum Eigenvalue Test			Trace Test		
Ho:	H1:	Statistic+	95 % CV	H1:	Statistic+	95 % CV
r = 0	r = 1	21.24**	14.1	r ≥ 1	25.29**	15.4
r ≤ 1	r = 2	4.05*	3.8	r ≥ 2	4.05*	3.8

4. Variables: Energy Import Cost, Energy Purchase. Lag = 10.
   Eigenvalues: 0.628, 0.0063.

	Maximum Eigenvalue Test			Trace Test		
Ho:	H1:	Statistic+	95 % CV	H1:	Statistic+	95 % CV
r = 0	r = 1	9.9	14.1	r ≥ 1	10.54	15.4
r ≤ 1	r = 2	0.65	3.8	r ≥ 2	0.65	3.8

5. Variables: Line Loss, Sales. Lag = 2.
   Eigenvalues: 0.24, 0.001.

	Maximum Eigenvalue Test			Trace Test		
Ho:	H1:	Statistic+	95 % CV	H1:	Statistic+	95 % CV
r = 0	r = 1	9.33	14.1	r ≥ 1	9.37	15.4
r ≤ 1	r = 2	0.04	3.8	r ≥ 2	0.04	3.8

Notes: + = Test statistics are with small sample correction.
**/* = Significant at 1% / 5 % level. CV = Critical Value.

Table 7: Marginal Costs and Peak Load Prices for the Kerala Power System

	Marginal Costs in 1999-2000, at constant 1993-94 prices			Marginal	In 1999-2000
	Operating Cost Rs./kWh	Capital Cost Rs./kW	Purchase Cost Rs./kWh	Loss Factor in 1999-2000	Peak Load : 2177 MW Generation: 7655.57 MU Purchase : 4275.04 MU Sales : 9812.88 MU
Over 1960-61	0.659	2139.33	1.325	0.21	Peak period duration:
Over 1970-71	0.761	2200.7	1.322	0.217	Half-an-hour a day: 182.5 hours
Over 1980-81	1.321	2145.42	1.324	0.187	3 hours a day : 1095 hours
Over 1990-91	1.194	3407.45	1.544	0.211	

	Rs./kWh in 1999-2000 at constant prices, Peak Period: Half an Hour Daily							
	Marginal Energy Cost		Marginal Capital Cost			Peak Load Prices		Uniform Price
	Adjusted	Alternative	Peak	Off-Peak	Uniform	Peak	Off-Peak	
Over 1960-61	1.086	1.091	7.247	0.154	0.151	8.333	1.24	1.237
Over 1970-71	1.17	1.169	7.454	0.159	0.155	8.624	1.329	1.325
Over 1980-81	1.57	1.607	7.267	0.155	0.151	8.837	1.725	1.721
Over 1990-91	1.598	1.604	11.542	0.246	0.24	13.14	1.844	1.838

	Rs./kWh in 1999-2000 at current prices, Peak Period: Half an Hour Daily							
	Marginal Energy Cost		Marginal Capital Cost			Peak Load Prices		Uniform Price
	Adjusted	Alternative	Peak	Off-Peak	Uniform	Peak	Off-Peak	
Over 1960-61	1.577	1.585	10.529	0.224	0.219	12.106	1.801	1.796
Over 1970-71	1.701	1.699	10.831	0.23	0.226	12.532	1.931	1.927
Over 1980-81	2.281	2.335	10.559	0.225	0.22	12.84	2.506	2.501
Over 1990-91	2.321	2.331	16.771	0.357	0.349	19.092	2.678	2.67

	Rs./kWh in 1999-2000 at constant prices, Peak Period: Three Hours Daily							
	Marginal Energy Cost		Marginal Capital Cost			Peak Load Prices		Uniform Price
	Adjusted	Alternative	Peak	Off-Peak	Uniform	Peak	Off-Peak	
Over 1960-61	1.086	1.091	1.293	0.185	0.162	2.379	1.271	1.248
Over 1970-71	1.17	1.169	1.33	0.19	0.166	2.5	1.36	1.336
Over 1980-81	1.57	1.607	1.296	0.185	0.162	2.866	1.755	1.732
Over 1990-91	1.598	1.604	2.06	0.294	0.257	3.658	1.892	1.855

	Rs./kWh in 1999-2000 at current prices, Peak Period: Three Hours Daily							
	Marginal Energy Cost		Marginal Capital Cost			Peak Load Prices		Uniform Price
	Adjusted	Alternative	Peak	Off-Peak	Uniform	Peak	Off-Peak	
Over 1960-61	1.577	1.585	1.878	0.268	0.235	3.455	1.845	1.812
Over 1970-71	1.701	1.699	1.932	0.276	0.242	3.633	1.977	1.943
Over 1980-81	2.281	2.335	1.884	0.269	0.235	4.165	2.55	2.516
Over 1990-91	2.321	2.331	2.992	0.427	0.374	5.313	2.748	2.695

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