Energy Management Training Program

Monograph 2

Energy Pricing and Demand Management

M. Munasinghe
World Bank
Washington, D.C.

prepared for the
Office of Energy -
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National Center for Analysis
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Brookhaven National Laboratory
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DEMAND MANAGEMENT POLICIES:

IIa. Principles of Integrated Energy Pricing

and

IIIa. Application and Impact of Pricing Policy 1/

by

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I. Introduction

In recent years, decision makers in an increasing number of countries have realized that energy sector investment planning and pricing should be carried out on integrated basis, e.g., within the framework of a national energy master plan which determines energy policy, ranging from short-run supply-demand management to long-run planning. However, in practise investment planning and pricing are still carried out on an ad-hoc and at best partial or sub-sector basis. Thus typically, electricity or oil sub-sector planning has traditionally been carried out independently of each other as well as of other energy sub-sectors. As long as energy was cheap such partial approaches and the resulting economic losses were acceptable, but lately, with rising energy costs (especially of oil), changes in relative fuel prices, and substitution possibilities, the advantages of an integrated energy policy have become evident.

In this paper the importance of coordinated energy planning and pricing will be emphasized, with particular reference to the inter-relationships among the pricing policies adopted in various energy sub-sectors such as electric power, petroleum, natural gas, coal and traditional fuels (e.g., firewood, crop residues and dung). Non-conventional sources can also be fitted into this framework. We will focus on the LDC context where generally, higher levels of market distortion, shortages of foreign exchange and resources for development, larger numbers of poor households

1/ The opinions expressed in this paper are the authors, and do not necessarily represent the views of the World Bank or its affiliated organizations.

whose basic needs must be met, greater reliance on traditional fuels, and relative paucity of energy data, add to the already complicated problems faced by energy planners in the developed countries. We will also touch on the chief investment issues to the extent that they strongly influence pricing policy.

Before developing an integrated framework for power and energy pricing, it is necessary to briefly discuss what is meant by national energy planning. The broad underlying rationale is to make the best use of energy resources to promote socio-economic development and improve the welfare and quality of life of citizens. Therefore energy planning is an essential part of overall national economic planning, and should be carried out and implemented in close coordination with the latter. However, in energy planning, the principal emphasis is on the comprehensive and disaggregate analysis of the energy sector, with due regard for the main interactions with the rest of the economy. In a strictly technical sense, the energy planners role might be confined to seeking the least-cost method of meeting future energy requirements. However, energy planning also includes a variety of other objectives including reducing dependance on foreign sources, supplying basic energy needs of the poor, reducing the trade and foreign exchange deficit, priority development of special regions or sectors of the economy, raising sufficient revenues to finance energy sector development (at least partially), ensuring continuity of supply and price stability, preservation of the environment, and so on.

In general, energy planning requires analysis at the following three hierarchical levels in relation to fundamental national objectives:: (a) links between the energy sector and the rest of the economy; (b) interactions between different sub-sectors within the energy sector; and (c) activities in each individual energy sub-sector. The steps involved in the planning procedure usually include energy supply and demand analyses and forecasting, energy balancing,

policy formulation, and impact analysis, to meet short, medium and long-range goals. Initially, these activities may be carried out at a relatively simple level and later as data and local analytical capabilities improve more sophisticated techniques including computer modelling, could be implemented. The institutional structure should also be rationalized by setting up a central energy authority (CEA), or ministry of energy, with its principal focus on energy planning and policy making. The execution of policy, and day-to-day operations would remain the responsibility of line agencies like the electricity utilities or petroleum corporations which already exist in practically all countries.

II. Scope and Objectives of Pricing

To put pricing in proper context, we note that it is only one of the policy tools available for optimal supply-demand planning and management; others include physical controls, technical methods, (including research and development), and education & propaganda. Since these tools are interrelated, their use should be well coordinated. Physical controls are most effective in the short-run when there are unforeseen shortages of energy. All methods of physically limiting consumption such as load shedding and rotating power cuts in the electricity sub-sector, as well as reducing the supply of gasoline or banning the use of motor cars during some periods, are included in this category. Technical means include, on the supply side, the least cost or cheapest means of producing a given form of energy, the best mix of fuels, research and development of substitute fuels such as wood-alcohol for gasoline, and on the demand side, introducing higher efficiency energy conversion devices such as better stoves for woodfuel etc. Education and propaganda include, on the

supply side, efforts to make citizens aware of external diseconomies such as pollution, and supportive of re-afforestation schemes to preserve the environment, and on the demand side public education for energy conservation.

Pricing is a very important tool especially in the long run. As discussed below the pricing and investment decisions should be closely related. However, energy supply systems e.g., electricity generation, transmission and distribution, oil and gas wells and pipelines, coal mines, forests etc., usually require large capital investments with long lead times and lifetimes. Therefore once the investments decision is made, usually on the basis of the conventional least-cost method of meeting demand by sub-sector, with due regard for interfuel substitution possibilities, there is a lock-in effect with respect to supply, and thus prices should be related to the long-run horizon of planning. On the demand side also, energy conversion devices, e.g., motor cars, gas stoves, electric appliances, machines and so on, are expensive relative to average income levels and have relatively long lifetimes, thus limiting the ability of consumers to respond to changes in relative fuel prices in the short run.

The objectives of energy pricing are closely related to the goals of energy planning, but are more specific. First, the economic growth objective requires that pricing policy should promote economically efficient allocation of resources both within the energy sector and between it and the rest of the economy. In general terms, this implies that future energy use would be at

optimal levels, with the price (or willingness-to-pay of the consumer) for the marginal unit of energy used reflecting the incremental resource cost of supply to the national economy. Relative fuel prices should also influence the pattern of consumption in the direction of the optimal or least-cost mix of energy sources required to meet future demand. Distortions and constraints in the economy necessitate the use of shadow prices and economic second-best adjustments, as described in the next section.

Second, the social objective recognizes the basic right of all citizens to be supplied with certain minimum energy needs. Given the existence of significant numbers of poor consumers and also wide disparities of income, this implies subsidized prices, at least for low income consumers.

Third, the government would be concerned with financial objectives relating to the viability and autonomy of the energy sector. This would usually be reflected, by pricing policies which permitted institutions (typically, government-owned) in the different energy sub-sectors to earn a fair rate of return on assets and to self-finance an acceptable portion of the investments required to develop future energy resources.

Fourth, energy conservation is also an objective of pricing policy. While prevention of unnecessary waste is an important goal, there often are other reasons underlying the desire to conserve certain fuels. These include the desire for greater independance from foreign sources (e.g., oil imports), the need to reduce the consumption of woodfuel due to deforestation and erosion problems, etc.

Fifth, we recognize a number of additional objectives, such as the need for price stability to prevent shocks to consumers from large price fluctuations, the need for simplicity in energy pricing structures to avoid confusing the public and simplify metering and billing, and so on.

Finally, there are other specific objectives such as promoting regional development (e.g., rural electrification) or specific sectors (e.g., export-oriented industries), as well as other socio-political, legal and environmental constraints.

In summary, therefore. ~~price is most effective as~~ a long-run policy tool. From the viewpoint of economic efficiency, the price indicates to the suppliers, the consumers willingness-to-pay and use-value of energy; while to the consumers, it signals the present and future opportunity costs of supply based on various energy sources.

We conclude this section with a brief review of the pervasive role that most governments play in the pricing of commercial energy resources, and the relative neglect of issues relating to traditional forms of energy. Governments exercize direct influence, usually through the ownership of energy sources or price controls. Indirect influences occur through such means as taxes, import duties, subsidies, market quotas, taxes on energy-using equipment and government-guided investments in energy resources.

In practically all developing countries, the electric utility is government owned. In oil and gas production, refining and distribution, as well as coal mining, both public and private organizations operate, often side-by-side. However, irrespective of the form of ownership, all governments excercize some form of price control, usually at several levels including the production stage, refinery, after transport or transmission, wholesale or retail, and so on. Income and excise taxes are also levied from both public

and private energy sector companies.

Generally, certain fuels in specific uses tend to be subsidized, although leakages and abuses of subsidies by non-targeted consumer groups also occur. Thus kerosene for lighting and cooking, rural electricity for lighting and agricultural pumping, and diesel for transportation commonly qualify for subsidies. Cross-subsidies between different fuels, user groups and geographic regions exist. Thus highly priced gasoline may finance the subsidy on kerosene, industrial electricity users may subsidize household consumers, and a uniform national pricing policy usually implies subsidization of energy users in remote areas by those living in urban centers. The principal problem associated with subsidies are that the energy producer may not be able to raise sufficient revenues for financing investment to meet expanding demand, or even to maintain existing facilities, thus eventually leading to shortages. Furthermore, cross-subsidies give consumers the wrong price-signals with consequent misallocation of investments.

Import and export duties, excise and sales taxes are levied, often by several levels of government, from federal to municipal, at various stages in the production, processing, distribution and retailing chain. In many developing countries, the combined levies are several hundred percent of the original product price for some items, and negative or close to zero for others. Several less obvious methods such as property taxes, water rights and user charges, and franchise fees are also used to influence energy use. Energy prices are also affected by the wide range of royalty charges, profit sharing schemes, and exploration agreements, between governments and multinational companies for the development of oil and gas resources.

Other policy instruments are often used to reinforce pricing policies, such as quotas on imported or scarce forms of energy, coupled with high prices.

Conservation regulations may affect maximum depletion rates for oil and gas, while the availability of hydropower from some multipurpose dams may be subordinate to use of water for irrigation or river navigation. Many special policies involving tax holidays and concession, import subsidies, export bonuses, government loans or grants, high taxes on large automobiles etc. are also used to affect energy use.

The traditional fuels sub-sector has been relatively neglected because transactions involving these forms of energy are usually of a non-commercial nature. However, there is growing acceptance of the coordinated use of indirect methods such as displacement of fuelwood used in cooking by subsidizing kerosene and LPG, increasing the supply of fuelwood by re-afforestation programs and effective distribution of charcoal, enforcing stiffer penalties for illegal felling of trees, proper watershed management, and so on.

III. Economic Framework

Because the objectives mentioned above are often not mutually consistent, a realistic integrated energy pricing structure must be flexible enough to permit tradeoffs among them. To achieve this, the formulation of energy pricing policy must be carried out in two stages. In the first stage, a set of prices which strictly meets the economic efficiency objective is determined, based on a consistent and rigorous framework. The second stage consists of adjusting these efficient prices (established in the first step), to meet all the other objectives. The latter procedure is more ad-hoc, with the extent of the adjustments being determined by the relative importance attached to the different objectives. In the rest of this section, we discuss the importance of shadow pricing and develop the economic framework which permits the efficient pricing of energy. The second stage adjustments due to non-economic factors are discussed in the next section. Shadow pricing theory has been

developed mainly for use in the cost-benefit analysis of projects. 1/ However, since investment decisions in the energy sector are closely related to the pricing of energy outputs, for consistency the same shadow pricing framework should be used in both instances. Shadow prices are used instead of market prices (or private financial costs), to represent the true economic opportunity costs of resources.

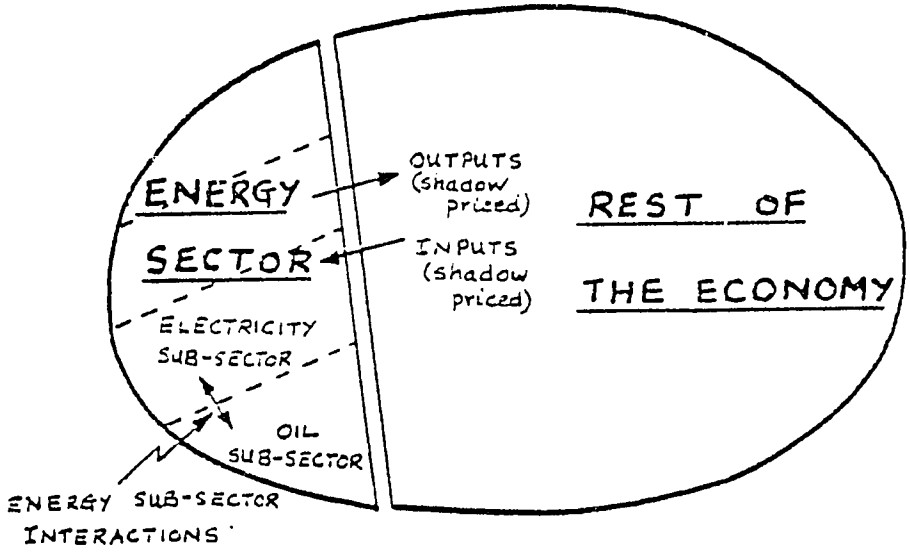
In the idealized world of perfect competition the interaction of atomistic profit maximizing producers and atomistic utility maximizing consumers yield market prices which reflect the correct economic opportunity costs, and scarce resources including energy will be efficiently allocated. However, in the real world, distortions due to monopoly practices, external economies and diseconomies (which are not internalized in the private market), interventions in the market process through taxes, import duties and subsidies, etc., all result in market prices for goods and services, which may diverge substantially from their shadow prices or true economic opportunity costs. Therefore, shadow prices must be used in investment and output pricing decisions, to ensure economically efficient use of resources. Moreover, if there are large income disparities, we will see later that even these "efficient" shadow prices must be further adjusted, especially to achieve socially equitable energy pricing policies for serving poor households.

It is important to realize that lack of data, time and manpower resources, particularly in the LDC context, will generally preclude the analysis

1/ For general use of shadow prices in developing countries, see: L. Squire and H. Van der Tak, Economic Analysis of Projects, Johns Hopkins, Baltimore, 1975 ; and I.M.D. Little and J.A. Mirrless, Project Appraisal and Planning for Developing Countries, Basic Books, New York, 1974 . For more specific application to the energy sector, see: Mohan Munasinghe, The Economics of Power System Reliability and Planning, Johns Hopkins, Baltimore, 1979 b, Chap.9.

of a full economy-wide model when making energy-related decisions. 1/ Instead the partial approach shown in Figure 1 may be used, where key linkages and resource flows between the energy sector and the rest of the economy, as well as interactions among different energy sub-sectors are selectively identified and analyzed, using appropriate shadow prices such as the opportunity cost of capital, shadow wage rate, marginal opportunity cost for different fuels, and so on. In practise, surprisingly valuable results may be obtained from even relatively simple models and assumptions.

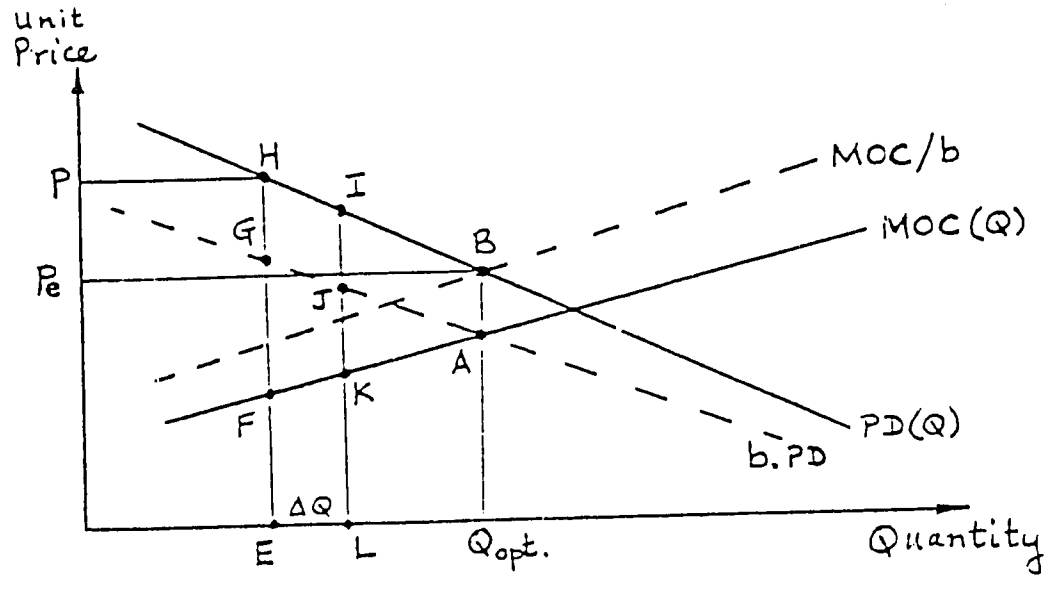
Figure 1. Partial Equilibrium Framework for Energy Pricing



1/ This holistic approach or general equilibrium analysis is conceptually important. For example, the efficient shadow price of a given resource may be represented by the change in value of aggregate national consumption or output, due to a small change in the availability of that resource. A more detailed discussion of general versus partial equilibrium in relatio to energy sector analysis is given in Mohan Munasinghe, op.cit., 1979b. For a discussion of economy-wide energy models, see for example: National Academy of Sciences, Energy Modeling for an Uncertain Future, Washington, D.C., 1978.

To clarify the basic concepts involved in optimal energy pricing we first analyze a relatively simple model. Next the effects of more complex features including short-run versus long-run dynamic considerations, capital indivisibilities, joint output cost allocation, quality of supply, and price feedback effects on demand are examined. The process of establishing the efficient economic price in a given energy sub-sector may be conveniently analyzed in two steps (see Appendix A for details). First, the marginal opportunity cost (MOC) or shadow price of supply must be determined. 1/ Second, this value has to be further adjusted to compensate for demand side effects arising from distortions in the prices of other goods, including other energy substitutes. From a practical viewpoint, an optimal pricing procedure which begins with MOC is easier to implement because supply costs are generally well defined (from technological-economic considerations), whereas data on the demand curve is relatively poor.

Figure 2. Efficient Pricing With Shadow Prices



1/ The same model will be modified in the next section to establish socially equitable subsidized prices for low income consumers.

Suppose that the marginal opportunity cost of supply in a given energy sub-sector is the curve MOC(Q) shown in Figure 2. For a typical non-traded item like electricity, MOC which is generally upward sloping is calculated by first shadow pricing the inputs to the power sector and then estimating both the level and structure of marginal supply costs (MSC) based on a long-run system expansion program.[1/] For tradable items like crude oil and for fuels which are substitutes for tradables at the margin, the international or border prices of the tradables (i.e., c.i.f. price of imports or f.o.b. price of exports, with adjustments for internal transport and handling costs) are appropriate indicators of MOC.[2/] For most developing countries, such import or export MOC curves will generally be flat or perfectly elastic. Other fuels such as coal and natural gas could be treated either way depending on wheter they are tradables or non-traded.[3/] The MOC of non-renewable, non-traded energy sources will generally include a "user cost" or economic rent component, in addition to the marginal costs of production. The economic value of traditional fuels are the most difficult to determine because in many cases there is no established market. However, as discussed later, they may be valued indirectly on the basis of the savings on alternative fuels such as kerosene, the opportunity costs of labour for gathering firewood, and/or the external costs of deforestation and erosion.

Thus, for a non-traded form of energy, MOC is the opportunity cost of inputs used to produce it plus a user cost where relevant, while for a tradable fuel or a substitute, MOC represents the marginal foreign exchange

1/ For a detailed discussion of the procedures used in the electric power sub-sector, see: Mohan Munasinghe, "Electric Power Pricing Policy", Staff Working Paper No. 340, World Bank, Washington, D.C., June 1979a. In this sub-sector MSC is also called the long-run marginal cost (LRMC).

2/ We note that the use of border prices does not require the assumption of free trade, but implies that the numbraire or unit of value for shadow pricing is essentially uncommitted foreign exchange (but converted into local currency at the official exchange rate). For details, see L. Squire and H. Van der Tak, op.cit.

3/ A non-traded item is generally characterized by a domestic supply price that lies above the f.o.b. price of exports, but below the c.i.f. price of imports.

cost of imports or the marginal export earnings foregone. In each case, MOC measures the shadow priced economic value of alternative output foregone, because of increased consumption of a given form of energy. After identifying the correct supply curve, we next examine demand-side effects, especially second best corrections which capture interactions between different energy sub-sectors.[1/] This second step is just as important as the first one, and therefore it will be examined in some detail.

In Figure 2, the market priced demand curve for the form of energy under consideration is given by the curve PD(Q), which is the willingness-to-pay of consumers. Consider a small increment of consumption ΔQ at the market price level p. The traditional optimal pricing approach attempts to compare the incremental benefit of consumption due to ΔQ, i.e., the area between the demand curve and X-axis, with the corresponding supply cost, i.e., the area between the supply curve and X-axis. However, since MOC is shadow priced, PD must also be transformed into a shadow priced curve to make the comparison valid. This is done by taking the increment of expenditure $p.\Delta Q$ and asking the question: "what is the shadow priced marginal cost of resources used up elsewhere in the economy if the amount $p.\Delta Q$ (in market prices) was devoted to alternative consumption (and/or investment)?.

Suppose that the shadow cost of this alternative pattern of expenditure is $b(p.\Delta Q)$, where b is called a conversion factor. Then the transformed PD curve which represents the shadow costs of alternative consumption foregone is given by b.PD(Q); where in Figure 2, it is assumed that $b < 1$.

1/ The general theorem of the second-best shows, for example, that if the price of a given fuel is not set at it's MOC, then the efficient price of a close substitute also must diverge from it's own MOC. For a detailed discussion of the theory of the second-best in economics, see: D.M. Winch, Analytical Welfare Economics, Penguin Books, Harmondsworth, U.K., 1971.

Thus at the price p, incremental benefits EGJL exceed incremental costs EFKL. The optimal consumption level is Q_{opt}, where the MOC and b.PD curves cross, or equivalently where a new pseudo-supply curve MOC/b, and the market demand curve PD intersect. The optimal or efficient selling price to be charged to consumers(because they react only along the market demand curve PD, rather than the shadow priced curve b.PD) will be: p_e = MOC/b, at the actual market clearing point B. At this level of consumption, the shadow costs and benefits of marginal consumption are equal i.e., MOC = b.PD. Since b depends on user specific consumption patterns, different values of the efficient price p_e may be derived for various consumer categories, all based on the same value of MOC. We clarify the foregoing by considering several specific practical examples.

First, suppose that all the expenditure ($p.\Delta Q$) is used to purchase a substitute fuel i.e., complete substitution. Then the conversion factor b is the relative distortion or ratio of the shadow price to market price of this other fuel. Therefore p_e=MOC/b, represents a specific second-best adjustment to the MOC of the first fuel, to compensate for the distortion in the price of the substitute fuel.[1/] Next, consider a less specific case in which the amount ($p.\Delta Q$) is used to buy an average basket of goods. If the consumer is a residential one, b would be the ratio of the shadow price to the market price of the household's market basket (here, b is also called the consumption conversion factor). The most general case would be when the consumer was unspecified, or detailed information on consumer categories was

1/ For example, MOC_{rr} could represent the long run marginal cost of rural electricity (for lighting), and the substitute fuel could be imported kerosene. Suppose that the (subsidized) domestic market price of kerosene is set at one half it's import (border) price, for socio-political reasons. Then b = 2, and the efficient selling price of electricity p_e=MOC_{rr}/2 (ignoring differences in quality of the two fuels, capital costs of conversion equipment such as light bulbs. kerosene lamps, partial substitution effects etc.: a more refined analysis of substitution possibilities would have to incorporate these additional considerations). It would be misleading however, to then attempt to justify the subsidized kerosene price on the basis of comparison with the newly calculated low price of electricity. Such circular reasoning is far more likely to occur when pricing policies in different energy subsectors are uncoordinated, rather than in an integrated energy pricing framework. We note that all these energy sector subsidies must be carefully targeted to avoid leakages and abuses, as discussed in the next section.

was unavailable, so that b would be the ratio of the official exchange rate (OER) to the shadow exchange rate (SER), also called the standard conversion factor (SCF).[1/] This represents a global second-best correction for the divergence between market and shadow prices averaged throughout the economy.[2/]

IV. Extensions of the Basic Model

The analysis so far has been static. However, in many instances the situation with regard to the availability of a given energy source, interfuel substitution possibilities, and so on, tends to vary over time, thus leading to disequilibrium in certain fuel markets, and divergence of the short-run price from the long-run optimal price. This aspect is illustrated below by means of an example which shows how the optimal depletion rate and time path for MOC of a domestic non-renewable resource will be affected by varying demand conditions, especially tradability, extent of reserves, and substitution possibilities.

Suppose that the present-day marginal supply cost (MSC) (including extraction costs, and additional transport and environmental costs, etc., where appropriate) of a domestic energy source such as coal lies below the thermal equivalency price of an internationally traded fuel (e.g., petroleum, or high quality coal), as indicated by points A and B respectively, in Figure 3.[3/] The internationa

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1/ Note that with the foreign exchange numeraire, conversion of domestic price values into shadow price equivalents by application of the SCF to the former, is conceptually the inverse of the traditional practise of multiplying foreign currency costs by the SER (instead of the OER) to convert to the domestic pric equivalent.

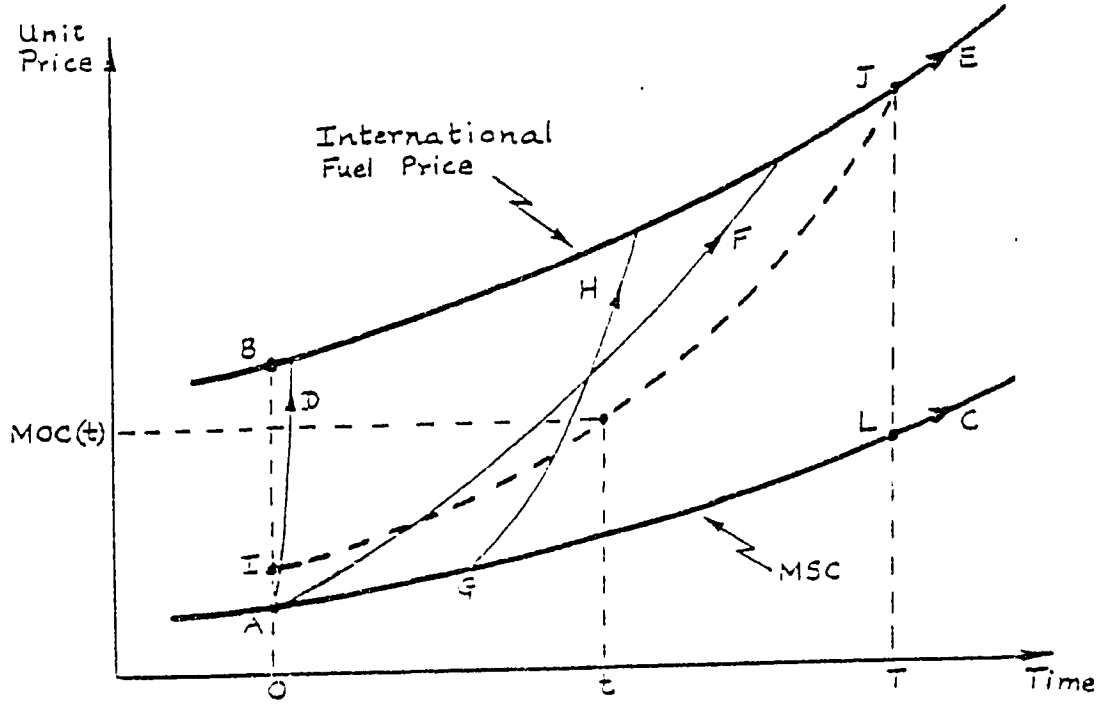
2/ For example, suppose the border price of imported diesel is Pesos 4 per litre (i.e., USc20 per litre, converted at the OER, of Pesos 20 per US$). Let the appropriate SER which reflects the average level of import duties and export subsidies be Pesos 25 per US$. Therefore SCF = OER/SER = 0.8, and the appropriate strictly efficient selling price of diesel: P_e=4/0.8 = Pesos 5 per lit

3/ Thermal equivalents are defined as the unit quantities of two substitutable fuels which provide the same useful energy output in a given use (i.e., including the efficiency of conversion). We note that the choice between the energy forms would depend on the quality of the final heat output, capital and handling costs of conversion and so on, but in order to simplify the analysis here we abstract from these problems and compare the fuels only on the basis of unit price.

energy price which acts as the bench-mark is assumed to rise steadily in real terms, along the path BE. Let us first examine two polar extremes based on simple, intuitively appealing arguments.

First, if the reserves are practically infinite and the use of this fuel at the margin will not affect exports or substitution for imports of traded fuels, then the MOC of the domestic energy source in the long-run would continue to be based on the marginal supply cost, i.e., along the path AC, which is upward sloping to allow for increases in real factor costs or extraction costs. On the other hand, suppose there is a ready export market for the indigenous resource, or substitution possibilities with respect to imported fuels. Thus the marginal use of this resource will reduce export earnings or increase the import bill for the international fuels in the short-run, because the reserves are small or output capacity is limited. Then, the marginal opportunity cost would tend to follow the path AD and rise quickly towards parity with the international energy price.

Figure 3. Dynamic Price Paths for Domestic Exhaustible Energy



The actual situation is likely to be between these two extremes, thus yielding alternative price paths such as AFE, or AGHE. Here, the initial use of the resource has no marginal impact on exports or import substitution, but there is gradual depletion of finite domestic reserves over time, and eventual transition to higher priced fuels in the future. For a given volume of reserves, the rate of depletion of the domestic energy source will be greater, and the time to depletion will be shorter if its price is maintained low for as long as possible (i.e., path AGHE) rather than when the price rises steadily (i.e., path AFE). The macroeconomic consequences of the former path are also more undesirable because of the sudden price increase at the point of transition, when the domestic resource is exhausted. In practise the price path may well be determined by non-economic factors. For example, the price of newly discovered gas or coal may have to be kept low for some years to capture the domestic market and displace use of imported liquid fuels (which continue to be subsidized for political reasons). In general. the desire to keep energy prices ~~low as long as possible~~ must be balanced against the need ~~to avoid a~~ large price shock in the future.[1/]

More rigorous dynamic models which maximize the net economic benefits of energy consumption over a long period, have been developed, to determine the optimal price path and depletion rate, but these depend on factors such as the social discount rate, size of reserves, growth of demand, cost and time lag needed to develop a backstop technology (which could replace the international energy

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1/ The preceding discussion is more useful for oil-importing or energy deficit LDC's. In the case of major oil exporters, the ability to influence the world market price and to determine the rate of resource depletion provides much greater flexibility. The huge foreign exchange surpluses and limited capacity to absorb investment imply decreased attractiveness of marginal export earnings coupled with the need to conserve oil resources. There is also greater ability to subsidize domestic oil consumption to meet basic needs and to accelerate economic development by increasing investment and expanding non-oil gross domestic product. See for example: M. Vajed Samii, "Economic Growth and Optimal Rate of Oil Extraction", OPEC Review, Vol.3, Autumn 1979, pp. 16-26.

price as the upper bound on price), and so on. Uncertainties in future supply and demand, e.g., the possibility of discovering new energy resources or technologies, add to the complexities of dynamic analysis. The classical argument developed in: H. Hotelling, "The Economics of Exhaustible Resources", Journal of Political Economy, 39, April 1931, pp. 137-75, indicates that the rate of increase in the optimal rent (or difference between price and marginal extraction cost) for the resource, should equal the rate of return on capital (r).[1/] This implies that the optimal path of MOC would be IJE in Figure 3, defined at any time t by the equation:

$$MOC(t) = MSC(t) + JL/(1+r)^{T-t}$$; where JL is the rent at the time of depletion T.[2/] Thus MOC consists of the current marginal costs of extraction, transport, environmental degradation etc. (MSC), plus the appropriately discounted "user cost" or foregone surplus benefits of future consumption (JL). As T approaches infinity, IJ would tend towards AC, which is the infinite reserve case, while as T falls to zero, IJ would approximate AD more closely, correponding to the case of very small reserves and rapid transition to the expensive fuel.

We now consider another type of dynamic effect due to the growth of demand from year 0 to year 1, which leads to an outward shift in the market demand curve from pD_0 to pD_1 as shown in Figure 4. Assuming that the correct market clearing price p_0 was prevailing in year 0, excess demand equal to GK will occur in year 1. Ideally, the supply should be increased to Q_1 and the new optimum market clearing

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1/ In our shadow pricing framework, r would be the social discount rate or "accounting rate of interest" (ARI).

2/ However, G. Heal, "The Relationship Between Price and Extraction Cost for a Resource with a Backstop Technology", The Bell Journal of Economics, 7, Autumn 1976, pp. 371 - 8, shows that under certain conditions, the optimal rent will fall to zero at the time of depletion. Other recent papers explore a variety of conditions, e.g., J.M. Hartwick, "Substitution Among Exhaustible Resources and Intergenerational Equity", Review of Economic Studies, March 1978, pp. 347 - 54; and R. Davison, "Optimal Depletion of an Exhaustible Resource with Research and Development Towards an Alternative Technology", ibid., pp. 355 - 67.

price established at p_1. However, the available information concerning the demand curve PD_1 may be incomplete, making it difficult to locate the point L.

Fortunately, the technical-economic relationships underlying the production function or known international prices usually permit the marginal opportunity cost curve to be determined more accurately. Therefore, as a first step, the supply may be increased to an intermediate level Q', at the price p'. Observation of the excess demand MN indicates that both the supply and if necessary, also the marginal cost price should be further increased. Conversely, if we overshoot L and end up in a situation of excess supply, then it may be necessary to wait until the growth of demand catches up with the over-supply. In this iterative manner, it is possible to move along the MOC curve towards the optimum market clearing point. It should be noted that, as we approach it, the optimum is also shifting with demand growth, and therefore we may never hit this moving target. However, the basic guideline of pegging the price to the marginal opportunity cost of supply and expanding output until the market clears, is still valid.

Next, we examine the practical complications raised by price feedback effects. Typically, a long-range demand forecast is made assuming some given future evolution of prices, a least cost investment program is determined to meet this demand, and optimal prices are computed on the basis of latter. However, if the estimated optimal price which is to be imposed on consumers is significantly different from the original assumption regarding the evolution of prices, then the first round price estimates must be fed back into the model to revise the demand forecast and repeat the calculation.

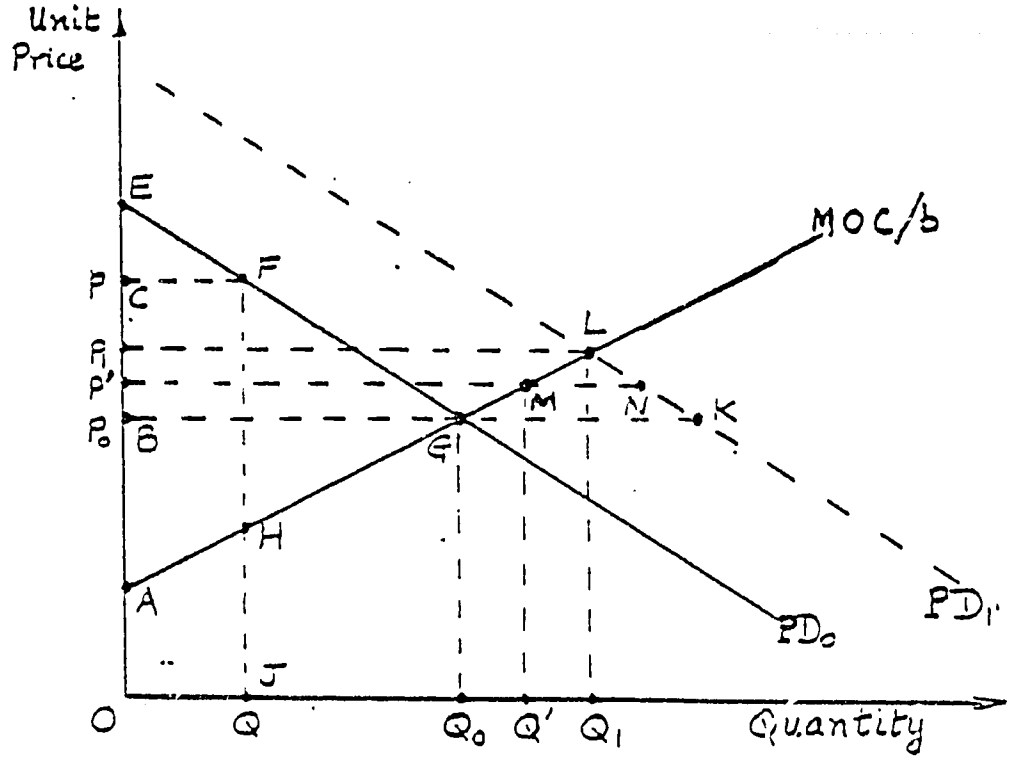

Figure 4. Dynamic Effects Due to Demand Curve Shifts.

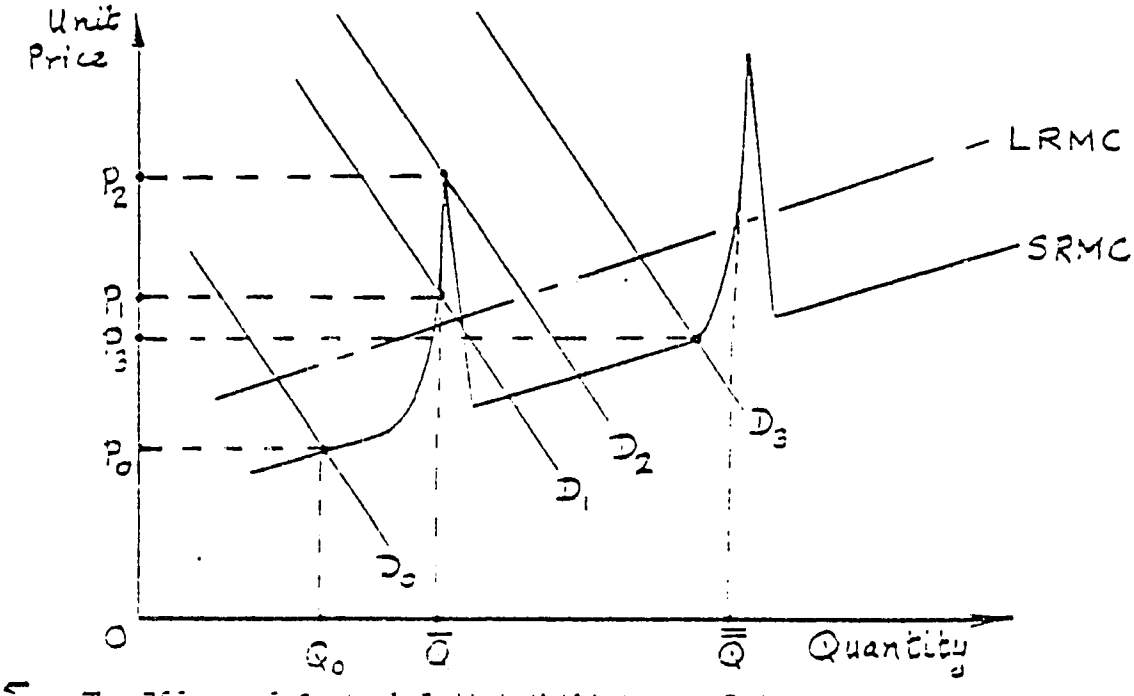

Figure 5. The Effect of Capital Indivisibilities on Price

In theory, this iterative procedure could be repeated until future demand, prices, and MOC estimates become mutually self-consistent. In practice, uncertainties in price elasticities of demand and other data may dictate a more pragmatic approach in which the MOC would be used to devise prices after only one iteration. The behavior of demand is then observed over some time period and the first round prices are revised to move closer to the optimum, which may itself have shifted as described earlier.

When MOC is based on marginal production costs, the effect of capita indivisibilities or lumpiness of investments causes difficulties in many energy sub-sectors. Thus, owing to economies of scale, investments for electric power systems, gas production and transport, oil refining, coal mining, re-afforestation etc. tend to be large and long-lived. As shown in Figure 5, suppose that in year 0, the maximum supply capacity is $\overline{Q}$, while the optimum price and output combination (p_o, Q_o) prevails, corresponding to the demand curve D_o and the short run marginal cost curve SRMC (e.g., variable, operating and maintenance costs).

As demand grows from D_o to D_1 over time and the limit of existing capacity is reached, the price must be increased to p_1 to clear the market, i.e., "price-rationing" occurs. When the demand curve has shifted to D_2 and the price is p_2, plant is added on to increase the capacity to $\overline{Q}$. However, as soon as the capacity increment is completed and becomes a sunk cost, price should fall to the old trend line of SRMC, e.g., p_3 is the optimum price corresponding to demand D_3. Generally, the large price fluctuations during this process will be disruptive and unacceptable to consumers. This practica problem may be avoided by adopting a long run marginal cost (LRMC) approach, which provides the required price stability while retaining the basic princip of matching willingness-to-pay and incremental supply costs. Essentially, the future capital costs of a single project or an investment program are

distributed over the stream of output expected during the lifetime of this plant.[1/] This average investment cost per unit of incremental output is added to variable costs (SRMC), to yield LRMC, as shown in Figure 5.[2/]

Another method of allocating capacity costs, known as peak load pricing, is particularly relevant for electricity and also natural gas. The basic peak load pricing model shown in Figure 6 has two demand curves; for example, D_{pk} could represent the peak demand during the x daylight and evening hours of the day when electric loads are large, while D_{op} would indicate the off-peak demand during the remaining (24-x) hours when loads are light. The marginal cost curve is simplified assuming a single type of plant with the fuel, operating and maintenance costs given by the constant a, and the incremental cost of capacity given by the constant b. The static diagram has been drawn to indicate that the pressure on capacity arises due to peak demand D_{pk}, while the off-peak demand D_{op} does not infringe on the capcity $\overline{Q}$. The optimal pricing rule now has two parts corresponding to two distinct rating periods (i.e., differentiated by the time of day);

peak period price : $p_{pk} = a + b$

off-peak period price: $p_{op} = a$

The logic of this simple result is that peak period users, who are the cause of capacity additions, should bear full responsibility for the capacity costs as well as fuel, operating and maintenance costs, while off-peak

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1/ For example, capital costs could be levelized or annuitized at the appropriate social discount rate and divided by the annual output, or an average incremental cost approach could be used; see M. Munasinghe, op.cit, 1979a. If continued demand growth is expected, consumers' initial willingness-to-pay a price equal to the annual equivalent LRMC is assumed to imply willingness to do so over the lifetime of the asset.

2/ Exceptions to the LRMC rule may lead to efficiency gains in certain cases. If substantial excess supply capacity exists, it could be appropriate to temporarily use SRMC (including both variable and user costs) as a basis for pricing to specific consumers. However SRMC priced supplies must be decreased as LRMC priced demand grows, and the temporary users of low priced supplies should not be permitted to become a permanent burden, e.g., interruptible load in electric power systems.

consumers only pay the latter costs.[1/] Peak load pricing can also be applied in different seasons of the year.

Related problems of allocating joint costs arise in other energy sub-sectors as well, e.g., allocation of capacity costs of natural gas, or of refinery costs among different distillates. The former may be treated like the electricity case. For oil products, the light refinery cuts such as kerosene, gasoline and diesel which are tradable have benchmark international prices. However, other items like heavy residual oils may have to be treated like non-tradables. Furthermore, associated gas which may be flared at the refinery, is often assumed to have a low MOC, although subsequent storage and handling for use as LPG will add to the costs. A more complicated approach would be the use of a programming model of a refinery to determine shadow prices of distillates based on solution of the dual problem.

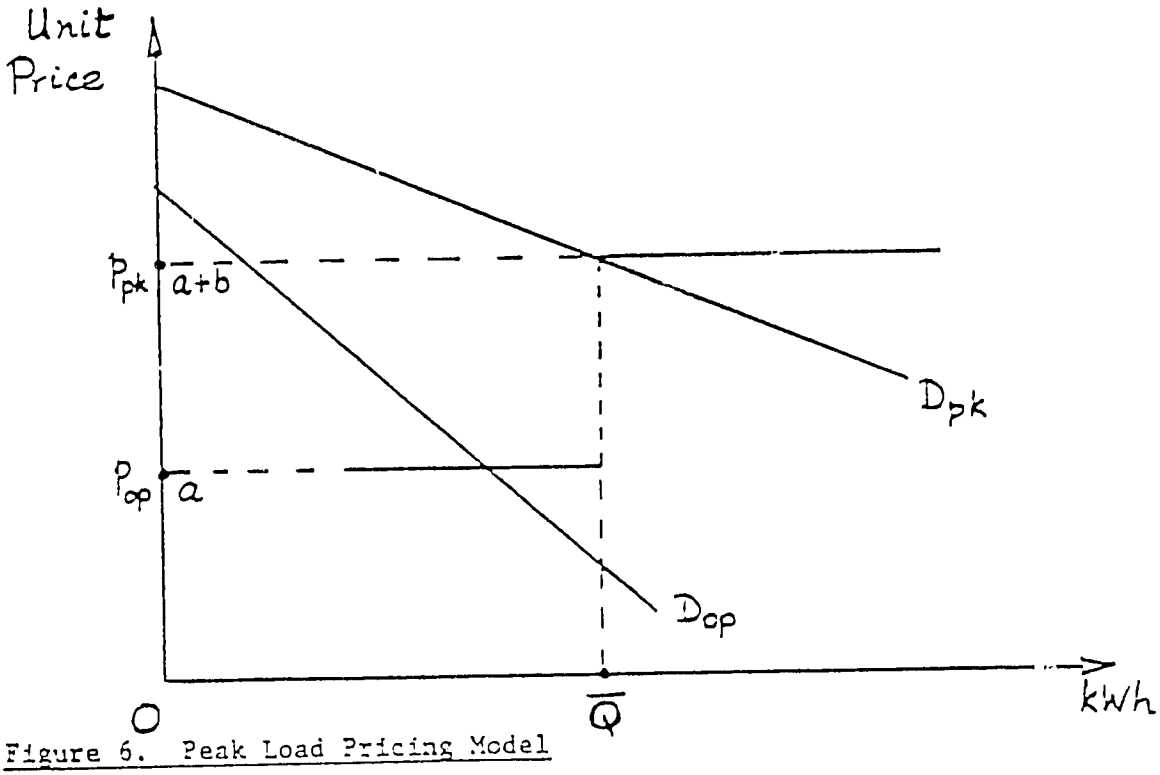

Figure 6. Peak Load Pricing Model

1/ The most recent peak load pricing models indicate that in an optimally planned system, marginal capacity costs should be allocated in proportion to marginal shortage costs during 2 or more different rating periods. We note that if the peak period is too narrowly defined, peak load pricin may shift the peak to another rating period; this would be an extreme cas of price feedback effects, discussed earlier.

A more general aspect which encompasses peak load pricing is that energy prices have to be structured. For example, the MOC shown in Figure 2 may vary by the type of consumer, geographic location, time and level of consumption, voltage level (for electricity), and so on. Then these values of MOC have to be modified to reflect demand side considerations (as discussed earlier). Therefore, the economically efficient prices in a given energy sub-sector may exhibit considerable structuring.

The interrelated issues of supply and demand uncertainty, safety margins and shortage costs also raise complications. We first illustrate this issue using electricity as an example, and then generalize the results for the other sub-sectors. Thus the least cost system expansion plan to meet an electricity demand forecast is generally determined assuming some (arbitrary) target level of system reliability (e.g., loss-of-load-probability or LOLP, reserve margin, etc.) Therefore, marginal costs depend on the target reliability level, when in fact economic theory suggests that reliability should also be treated as a variable to be optimized, and both price and capacity (or equivalently, reliability) levels should be optimized simultaneously. The optimum price is the marginal cost price as described earlier, while the optimum reliability level is achieved when the marginal cost of capacity additions (to improve the reserve margin) are equal to the expected value of economic cost savings to consumers due to electricity supply shortages averted by those capacity increments. These considerations lead to a more generalized approach to system expansion planning as shown below.[1/]

1/ For details see M. Munasinghe, "A New Approach to System Planning," IEEE Transactions on Power Apparatus and Systems, vol. PAS-79, (March-April, 1980).

Consider a simple expression for the net benefits (NB) of electricity consumption, which is to be maximized:

$$NB(D,R) = TB(D) - SC(D,R) - OC(D,R)$$

where TB = total benefits of consumption if there were no outages; SC = supply costs (i.e., system costs); OC = outage costs (i.e., costs to consumers of supply shortages); D = demand; and R = reliability.

In the traditional approach to system planning both D and R are exogenously fixed, and therefore NB is maximized, when SC is minimized, i.e., least cost system expansion planning. However, if R is treated as a variable:

$$\frac{d(NB)}{dR} = -\frac{\partial}{\partial R}(SC+OC) + \frac{\partial}{\partial D}(TB-SC-OC).\frac{\partial D}{\partial R} = 0$$

is the necessary first order maximization condition.

Assuming $\frac{\partial D}{\partial R} = 0$, yields: $\frac{\partial(SC)}{\partial R} = -\frac{\partial(OC)}{\partial R}$

Therefore, as described earlier, reliability should be increased by adding to capacity until the above condition is satisfied. An alternative way of expressing this result is that since TB is independent of R, NB is maximized when total costs: TC = (SC + OC) are minimized. The above criterion is one which effectively subsumes the traditional system planning rule of minimizing only the system costs. 1/

We note that this approach may be generalized for application in other energy sub-sectors. Thus while sophisticated measures of reliability like LOLP do not exist outside the power sub-sector, the concept of minimizing total costs to society is still relevant. For example, in oil and gas investment planning, the costs of shortages due to gasoline queues, lack of furnace oil or gas for domestic

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1/ The emphasis on outage costs requires greater effort to measure these costs; see M. Munasinghe and M. Gellerson,"Economic Criteria for Optimizing Power System Reliability Levels," The Bell Journal of Economics, vol. 10, Spring 1979, pp.353-65; and M. Munasinghe, "The Costs Incurred by Residential Electricity Consumers Due to Power Failures," Journal of Consumer Research, March 1980.

and industrial use, may be traded off against the supply costs of increased storage capacity and greater delivery capability incurred by augmenting surface transport or pipeline systems. Clearly, these additional considerations would modify the marginal costs of energy supply and thus affect optimal pricing policies.

Finally externalities, especially environmental considerations, have to be included as far as possible in the determination of efficient energy prices. For example, if the building of a new hydro-electric dam results in the flooding of land having recreational or agricultural value, or if urban transportation growth leads to congestion and air pollution, then these costs should be reflected in MOC. While such externality costs may be quite difficult to quantify, in certain cases, these costs may already be included (at least partially) on the supply side, in terms of measures taken to avoid environmental degradation e.g., cost of pollution control equipment at an oil refinery or coal-burning electricity plant, cost of landscaping strip-mined land, and so on.

Estimation of environmental costs are most problematic in the case of non-commercial or traditional energy sources such as woodfuel, where marginal opportunity costs could be based (when appropriate) on the externality costs of deforestation, erosion, loss of watershed and so on. Other measures of the economic value of traditional fuel would include the opportunity cost of labour required to collect woodfuel or the cost savings from displaced substitute fuels such as kerosene and LPG.

V. Adjustments to Efficient Prices to Meet Other Objectives

Once efficient energy prices have been determined, the second stage of pricing to meet social, financial, political and other constraints, must be carried out.

1/ The latter case could form the basis for raising fuel prices, vehicle licencing fees, road user charges, parking charges etc. in a large metropolis, relative to rural areas.

We note that efficient energy prices deviate from the prices calculated on the basis of financial costs, because shadow prices are used instead of the market prices. This is done to correct for distortions in the economy. Therefore, the constraints which force further departures from efficient prices (in the second stage of the pricing procedure) may also be considered as distortions which impose their own shadow values on the calculation. See M. Munasinghe and J.J. Warford, op cit., for details.

Subsidized Prices and Lifeline Rates

Socio-political or equity arguments are often advanced in favor of subsidized prices or "lifeline" rates for energy, especially where the costs of energy consumption are high relative to incomes of poor households. Economic reasoning based on externality effects may also be used to support subsidies, e.g., cheap kerosene to reduce excessive firewood use and prevent deforestation, erosion, etc. To prevent leakages and abuse of such subsidies, energy suppliers must act as discriminating monopolists. Targeting specific consumer classes (for example, poor households), and limiting the cheap price only to a minimum block of consumption is easiest to achieve, in practise, for metered forms of energy like gas or electricity. Other means of discrimination may also be required such as rationing, licensing, etc.[1/] All these complex and inter-related issues require detailed analysis.

The concept of a subsidized "social" block, or "lifeline" rate, for low income consumers has another important economic rationale, based on the income redistribution argument. We clarify this point with the aid of Figure 7 which shows the respective demand curves for energy AB and GH of low (I_1) and average (I_2) income domestic users, the social tariff P_s over the minimum consumption block 0 to Q_{min}, and the efficient price level P_e. All tariff levels are in domestic market prices. If the actual price $P = P_e$, then the average household will be consuming at the "optimal" level Q_2, but the poor household will not be able to afford the service.

1/ For example, a minimum ration of cheap kerosene for households, or a special lice for trucks using subsidized diesel oil and ban on diesel-driven passenger cars

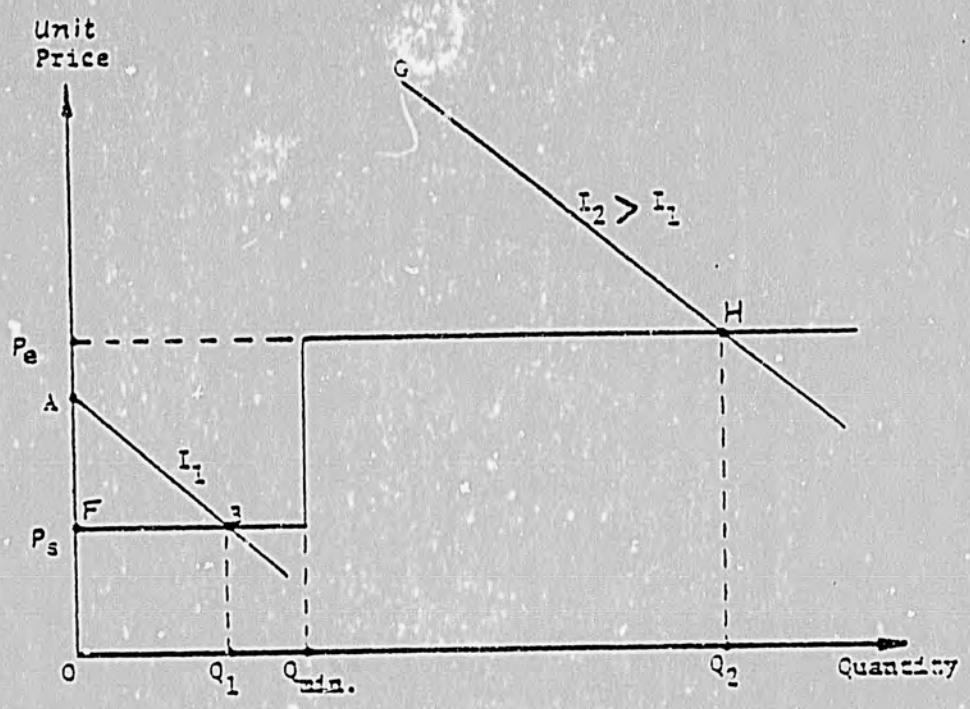

Figure 7 : ECONOMIC BASIS FOR THE SOCIAL OR LIFELINE RATE

If increased benefits accruing to the poor have a high social value, then, although in nominal domestic prices the point A lies below P_e, the consumer surplus portion ABF multiplied by an appropriate social weight w could be greater than the shadow price of supply (see Appendix A for details). The adoption of the block tariff shown in Figure 7, consisting of the lifeline rate P_s, followed by the full tariff P_e, helps to capture the consumer surplus of the poor user, but does not affect the optimum consumption pattern of the average consumer. 1/

1/ Ignoring the income effect due to reduced expenditure of the average consumer for the first block of consumption, i.e., up to Q_{min}.

In practice, the magnitude Q_{min} has to be carefully determined, to avoid subsiding relatively well-off consumers; it should be based on acceptable criteria for identifying "low income" groups, and reasonable estimates of their minimum consumption levels (e.g., sufficient to supply basic energy requirements for the household). The level of p_s relative to the efficient price may be determined on the basis of the poor consumer's income level relative to some critical consumption level, as shown in the Appendix. The financial requirements of the energy sector would also be considered in determining p_s and Q_{min}. This approach may be reinforced by an appropriate supply policy (e.g., subsidized house connections for electricity, special supply points for kerosene, etc.).

Financial Viability

The financial constraints most often encountered relate to meeting t revenue requirements of the sector, and are often embodied in criteria such as some target financial rate of return on assets, or an acceptable rate of contribution towards the future investment program. In principle, for state-owned energy suppliers, the most efficient solution would be to set price at the efficient level and rely on government to subsidize losses tax surpluses exceeding sector financial needs. In practice, some measure of financial autonomy and self-sufficiency is an important goal for the sector. Because of the premium that is placed on public funds, a pricing policy which results in failure to achieve minimum financial targets for continued operation of the sector, would rarely be acceptable. The converse and more typical case, where efficient pricing would result in financial surpluses well in excess of traditional revenue targets, may be politically unpopular, especially for an electric utility. Therefore in either case, changes in revenues have to be achieved by adjusting the efficient prices.

It is intuitively clear that discriminating between the various consumer categories so that the greatest divergence from the marginal

opportunity cost based price occurs for the consumer group with the lowest price elasticity of demand, and vice versa, will result in the smallest deviations from the "optimal" levels of consumption consistent with a strict efficiency pricing regime. 1/ Generally, in many countries the necessary data for the analysis of demand by consumer categories is rarely available, so rule-of-thumb methods of determining the appropriate tariff structure have to be adopted. However, if the energy sub-sector exhibits increasing costs (i.e., marginal costs greater than average costs), the fiscal implications should be exploited to the full. Thus for example electric power tariffs (especially in a developing country) constitute a practical means of raising public revenues in a manner which is generally consistent with the economic efficiency objective, at least for the bulk of the consumers who are not subsidized, while at the same time helping to supply basic energy needs to low income groups. Similar arguments may be made in the petroleum sub-sector where high prices for gasoline, based on efficiency, externality and conservation arguments, may be used to cross-subsidize the "poor-man's" fuel-kerosene, or diesel used for transportation. 2/

Other Considerations

There are several additional economic, political and social considerations that may be adequate justification for departing from a strictly efficient pricing policy. The decision to provide commercial energy such as kerosene or electricity in a remote rural area, which

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1/ See W. J. Baumol and D. F. Bradford, "Optimal Departures from Marginal Cost Pricing," Am. Econ. Rev., June 1970, pp. 265-283.

2/ However, a number of undesirable side effects may follow, such as the practise of mixing gasoline with kerosene, substitution of diesel for gasoline, and so on. The income distribution effects may also be perverse, with the relatively wealthy diverting cheap kerosene or diesel for use in vehicles or in industry.

often also entails subsidies because the beneficiaries are not able to pay the full price based on high unit costs, could be made on completely non-economic grounds, e.g., for general socio-political reasons such as maintaining a viable regional industrial or agricultural base, stemming rural to urban migration, or alleviating local political discontent. Similarly, uniform nation-wide energy prices are a political necessity in many countries, although this policy may, for example, imply subsidization of consumers in remote rural areas where energy transport costs are high, by energy users in urban centers. However, the full economic benefits of such a course of action may be much greater than the apparent efficiency costs which arise from any divergence between actual and efficient price levels. Again this possibility is likely to be much more significant in a developing country than in a developed one, not only because of the high cost of energy relative to incomes in the former, but also because the available administrative or fiscal machinery to redistribute incomes or achieve regional or industrial development objectives by other means is frequently ineffective.

The conservation objective (to reduce dependence on imported energy, improve the trade balance, and so on) usually runs counter to subsidy arguments. Therefore it may be necessary to restrict cheap energy to productive economic sectors which need to be strengthened, while in the case of basic energy needs of households, the energy price could be sharply increased for consumption beyond appropriate minimum levels. In other cases conservation and subsidized energy prices may be consistent. For example, cheap kerosene might be required, especially in rural areas, to reduce excessive woodfuel consumption, prevent deforestation, erosion, and so on.

It is particularly difficult to raise prices to any where near the efficient levels where low incomes and a tradition of subsidized energy have increased consumer resistance. In practice, price changes have to be gradual, in view of the costs which may be imposed on those who have already incurred expenditures on energy using equipment and made other decisions, while expecting

little or no changes in traditional energy pricing policies. At the same time, a steady price rise will prepare consumers for high future energy prices. The efficiency costs of a gradual instead of a sharp price rise can be seen as an implicit shadow value placed upon the social benefits that result from this policy.

Finally, owing to the practical difficulties of metering, price discrimination, and billing, and the need to avoid confusing consumers, the pricing structure may have to be simplified. Thus, the number of customer categories, rating periods, consumption blocks, and so on, will have to be limited. Electricity and gas offer the greatest possibilities for structuring. The degree of sophistication of metering depends on the net benefits of metering, problems of installation and maintenance, and so on. In general, various forms of peak electricity pricing (i.e., using maximum demand or time-of-day metering) would be particularly applicable to large medium and high voltage industrial and commercial consumers. However, for very poor consumers receiving a subsidized rate for electricity, a simple current limiting device may suffice, because the cost of even simple kWh metering may exceed the net benefits (equal to savings in supply costs due to reduced consumption, less the decrease in consumption benefits). For electricity or gas, different charges for various consumption blocks may be effectively applied with conventional metering. However, for liquid fuels like kerosene, subsidized or discriminatory pricing would usually requires schemes involving rationing and coupons, and could lead to leakage and abuses.

VI. Summary and Conclusions

The 1970's have been characterized by increasing real costs of energy prices and fluctuations in relative fuel prices. This paper has emphasized the importance of comprehensive energy planning, especially an integrated approach to energy pricing, due to the confusion arising from the

often conflicting nature of national objectives; the complexity of energy policy tools currently in use, including pricing, physical controls, technical methods, and public education; and the many types of energy sources which may be used in a variety of applications.

Energy policymakers in developing countries face special difficulties such as high levels of market distortion, shortages of foreign exchange and investment funds, large numbers of poor consumers whose basic energy needs must be met, and relatively greater usage of traditional fuels, in addition to the energy issues found in industrialized countries. Thus, an integrated pricing framework must begin with a clear statement of national objectives, and provide a method for trading-off among mutually contradictory goals. Important linkages between the energy sector and the rest-of-the-economy, as well as interactions between and activities within different energy sub-sectors must be analyzed using shadow prices, essentially within a partial equilibrium framework. For consistency, the shadow pricing methodology used for pricing energy sector outputs must be the same as the one used to make investment decisions. Special attention must also be paid to the hitherto neglected area of traditional fuels.

Energy pricing structures, disaggregated by energy sub-sector, are derived in two stages. First, the (shadow priced) marginal opportunity cost (MOC) of a given form of energy is determined based essentially on supply-side considerations. For a tradable form of energy, an appropriate measure of MOC would be the marginal cost of imports or export earnings foregone, with adjustments for local transport and handling costs. For non-traded fuels, MOC would be the marginal supply cost, plus a user cost component (in the case of non-renewable resources). Next, demand-side effects including distortions in the prices of other goods, especially substitute fuels, are used to derive from the MOC, the strictly efficient energy price level P_e.

In practise, this basic theoretical framework may be extended to cover dynamic effects relating to both supply and demand, price feedback effects, capital indivisibilities, problems of joint cost allocation, supply and demand uncertainty, shortage costs, and externalities.

In the second stage of the pricing procedure, the efficient price (p_e) is further adjusted to yield a realistic pricing structure which meets social-subsidy considerations, sector financial requirements, and other practical constraints such as the need to change prices gradually, simplicity of price structure (for metering and billing), and so on.

Direct pricing policies are usually inapplicable in the traditional fuels subsector, due to the lack of well developed markets for these forms of energy. Therefore, indirect methods including augmentation of supply, the appropriate pricing of substitute fuels, improvements in the efficiency of woodfuel energy conversion, punitive measures for excessive use, and so on, must be used in close coordination.

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Appendix A

Model for Optimal Energy Pricing Using Shadow Prices

In this appendix, a general expression for the socially optimal price in the sub-sector for energy type A is developed based on shadow prices, to compensate for distortions in the economy. From the general equation, results for optimal energy pricing are derived, for cases which reflect:

(a) a perfectly competitive economy (classical result);

(b) efficient prices, including economic second best considerations; and

(c) subsidized social prices or lifeline rates for poor consumers.

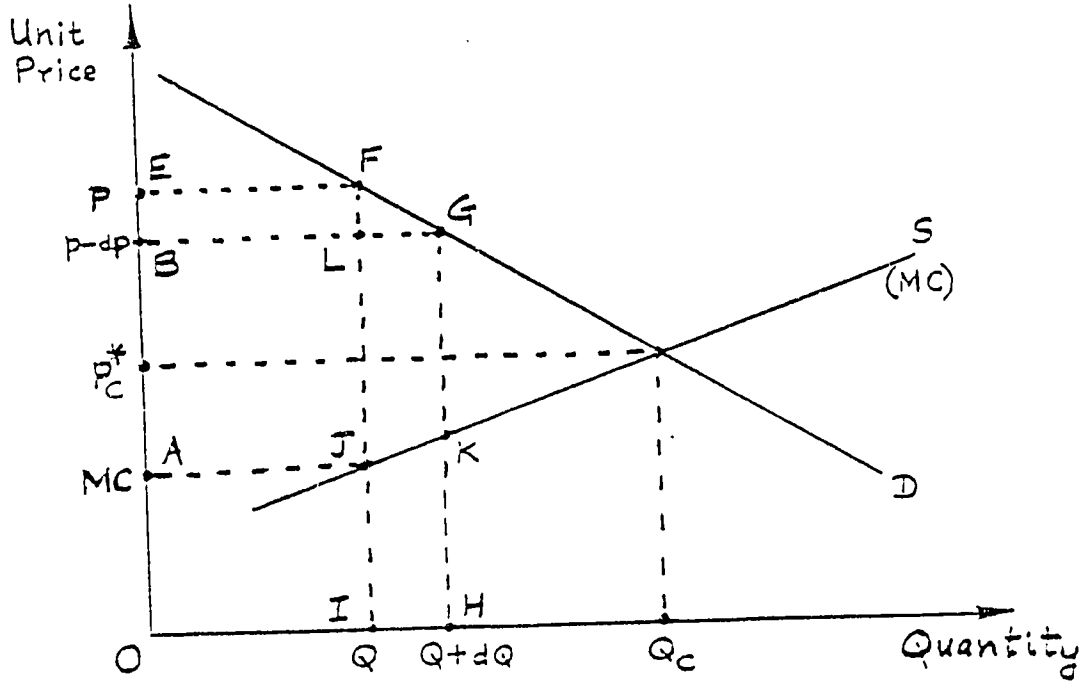

Figure A.1 SUPPLY AND DEMAND IN ENERGY SUB-SECTOR A

The supply and demand for a form of energy A is shown in Figure A.1, where S is the supply curve represented by the marginal cost of supply (evaluated at domestic market prices), and D is the corresponding demand curve for a specific consumer. Starting with the initial combination of price and consumption (p, Q), consider the impact of a small price reduction (dp), and the resultant increase in demand (dQ), on the net social benefits of energy A consumption.

Before evaluating the net social benefit of this price change, let us define the shadow pricing framework.[1/] First, suppose we calculate the marginal cost of supply MC withough shadow pricing, i.e., in market prices. Then a_p is defined as the energy A conversion factor (ACF) which transforms MC into the corresponding real economic resource cost, i.e., with correct shadow pricing, the marginal opportunity cost is MOC = (a_p.MC). Second, we assign a specific social weight W_c to each marginal unit of consumption (valued in market prices) of a given individual i in the economy, e.g., if this user of energy A is poor, the corresponding social weight may be much larger than for a rich customer, to reflect society's emphasis on the increased consumption of low income groups. Third, if the given individual's consumption of goods and services <u>other</u> than in the energy A sub-sector (valued in market prices), increases by one unit, then the shadow priced marginal cost of economi resources used (or the shadow cost to the economy) is b_i.

1/ For details, see: L. Squire and H. Van der Tak, <u>op.cit</u>.

As a result of the price reduction, the consumer is using dQ units more of energy A, which has a market value of (p. dQ) (i.e., area IFGH). 1/ However, the consumer's income has increased by the amount pQ - (p - dP). (Q+dQ), and assuming none of it is saved, this individual's consumption of other goods and services will increase by the amount (Q. dp-p. dQ), also valued in market prices (i.e., area BEFG minus area IFGH). Therefore, the consumer's total consumption, i.e., energy A plus other goods, will increase by the net amount (Q. dp) in market prices. This is the traditional increase in consumer surplus benefits. The shadow value of this increased consumption is W_c . (Q. dp) where W_c is the social weight appropriate to this consumer's income/consumption level.

Next consider the resource costs of these changes in consumption. The shadow cost of increasing the supply of energy A is (a_p.MC. dQ), (i.e., a_p times area IJKH), and the resources used up to provide the other additional goods consumed b_c.(Q. dp - p. dQ), where a_p is the conversion factor for energy A, and b_c is the conversion factor for other goods consumed by this consumer. Finally, the income change of producer of energy A (if any) must also be considered, but this effect may be ignored if we assume quite plausibly that the producer is the government.

The total increase in net social benefits due to the energy A price decrease is given by:

$$NB = W_c(p.\ dQ) - a_p.(MC.\ dQ) + (W_c - b_c).(Q.\ dp - p.dQ)$$

1/ The little triangle LFG may be neglected throughout this analysis because its area is (dp. dQ)/2, where both dp and dQ are small increments.

Therefore:

$$(dNB/dp) = Q\,[(W_c - b_c) + n.b_c] - n.a.\,.(MC/p)$$

where $n = (p.\,dQ/Q.\,dp)$ is the elasticity of demand (magnitude).

The necessary first order condition for maximizing net social benefits, in the limit, is $d(NB)/dp=0$. This yields the optimal price level:

$$p^* = a_p.\,MC/[b_c + (W_c - b_c)/n] \qquad (A.1)$$

This expression may be reduced to a more familiar form, by making some simplifying assumptions.

Case 1: Perfectly competitive economy where market prices and shadow prices are the same, and income transfer effects are ignored, i.e., no social weighting.

Therefore, $a_p = W_c = b_c = 1$, and equation (A.1) reduces to:

$$p_c^* = MC \qquad (A.2)$$

This is the classical marginal cost pricing result, where net social benefits are maximized when price is set equal to marginal cost at the market clearing point (p_c, Q_c) in Figure A.1.

Case 2: Income transfer effects ignored, because the marginal social benefit of consumption is equal to the marginal social cost to the economy of providing this consumption.

Therefore, $W_c = b_c$, and equation (A.1) becomes:

$$p_e^* = (a_p.MC)\,/\,b_c = MOC/b_c \qquad (A.3)$$

This is the optimal efficient price which emphasizes the efficient allocation of resources and neglects income distributional considerations.

As mentioned earlier, the marginal opportunity cost of energy A (MOC) may usually be evaluated in a straightforward manner (e.g., the international border price for a tradable fuel or, in the case of a non-tradable like electricity by applying the appropriate shadow prices to the least cost mix of technically technically determined inputs used in production). However, the conversion factor b_c depends crucially on the type of consumer involved.

For residential consumers of energy A, b_c represents the consumption conversion factor (CCF), which reflects the resource cost or shadow value of one (market priced) unit of the household's marginal consumption basket. If the CCF < 1, then $p_e^* > MOC$.

Another interesting case illustrates the application of equation (A.3) to correct for economic second-best consideration arising from energy substitution possibilities. As an extreme case, suppose all expenditures diverted from energy A consumption will be used to purchase alternative energy which is subsidized by the government (e.g., kerosene for lighting, or diesel for autogeneration). In this case, b_c is the ratio of the marginal opportunity cost of alternative energy to its market price; and may be written:

$$b_c = MOC_{ae}/p_{ae}$$

Thus from equation (A.3): 1/

$$p_e^* = MOC.(p_{ae}/MOC_{ae}) \qquad (A.4)$$

1/ The logic of this expression may be clarified by considering the case when the actual $p > p_e^*$. Then the shadow cost of one unit of expenditure on energy A is MOC/p while if this sum was used to purchase alternative energy the shadow cost would be MOC_{ae}/p_{ae}. Since $p > p_e^*$, $MOC/p > MOC_{ae}/p_{ae}$, and the country is better off if more energy A is used instead of the alternative energy. Therefore, p should be reduced to p_e^*. Similar reasoning can be used to show that if $p < p_e^*$, then p should be increased to the value p_e^*.

Since the alternative energy is priced below its border marginal cost, i.e., $b_c > 1$, then $p_e^* < MOC$ also. Therefore, the subsidization of substitute energy prices will result in an optimal energy A price which is below its shadow supply cost.

If it is not possible to determine the consumption patterns of specific consumer groups, then b_c could be defined very broadly as the average conversion factor for all energy A users, e.g., the SCF, as discussed in the text.

Case 3: General

Equation (A.1) is the optimal energy A price when shadow prices are used, which incorporate income distributional concerns.

Consider the case of a group of very poor consumers for whom we may assume: $W_c >> b_c(n-1)$. Therefore, equation (A.1) may be written:

$$p_s^* \approx n.MOC/W_c$$

An even greater simplification is possible if it is assumed that n = 1; thus

$$p_s^* = MOC/W_c$$

For illustration, suppose that the income/consumption level of these poor consumers (c) is 1/3 the critical income/consumption level ($\bar{c}$) which is like a poverty line. Then a simple expression for the social weight is:

$$W_c = \bar{c}/c = 3$$

Therefore, $p_s^* = MOC/3$, which is the "lifeline" rate or subsidized tariff appropriate to this group of low income consumers.

CHAPTER II

ENERGY CONSERVATION & EFFICIENCY

ENERGY MANAGEMENT TRAINING PROGRAM
ENERGY CONSERVATION AND EFFICIENCY

by Mohan Munasinghe

The relevance of energy conservation, its uses in the technical and economic context, and the means for effective implementation of conservation measures are discussed in this paper. In a period of rising energy prices and shortages, the goals of energy conservation seem to be intuitively acceptable and even laudable. Energy conservation is an important element of demand management and therefore, a valuable tool for achieving most of the objectives of integrated national energy planning discussed earlier.

The pursuit of energy conservation as a goal raises the issue of whether the reduction of energy consumption is always socially beneficial or desirable. Common sense indicates that while "wasteful" energy use should be discouraged, there is a limit beyond which conservation measures could cause more harm than good. In order to define desirable conservation levels more precisely, we start from the premise that the principle objective of a national economy is to maximize the collective welfare of its citizens. If aggregate consumption or production (e.g., Gross Domestic Product or GDP) is taken as a proxy for national welfare, then welfare maximization implies that scarce resources such as energy, capital labor and land should be used as efficiently as possible to maximize output.[1/] This suggests that the concepts of both economic and technical efficiency are important in determining desirable conservation policies.

Conservation measures either by cutting back use or through energy substitution usually lead to three types of consequences which are economically significant. First, the reduction or substitution in energy use gives rise to a net cost saving benefit, B. Second, the implementation of the conservation measure may involve additional costs, e.g., hardware costs, C_1. Finally, the reduction or substitution in energy consumption will usually imply a cost

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1/ For a detailed exposition of the market conditions and relationships that give rise to efficient production and consumption of economic goods and services, see for example: D. Henderson and D. Quandt, Microeconomic Theory.

or foregone benefit to the consumer, C_2, due to a reduction in the quantity and quality of energy available for end use. In general, if $B > (C_1 + C_2)$, then the conservation measure is economically justified, i.e., it will improve economic efficiency. The use of this basic cost-benefit test for economically justifying conservation measures will be explored and elaborated on later in this chapter.

In our discussion of pricing earlier, we argued that the rationale underlying efficient energy pricing at its opportunity cost is that decentralized market forces should be used as far as possible to establish economically optimal patterns and levels of energy consumption which maximize welfare. The acceptance of such optimal or desirable target levels of demand underline the fact that the conservation goal cannot be pursued as an end in itself. Therefore, wastage and conservation of energy should be assessed in relation to the use of energy in excess of the economically optimal or efficient consumption level. For example, if the price of diesel fuel is below its economic value or opportunity cost, then raising the price to this value would reduce demand to the optimal level, and therefore constitute an economically beneficial conservation policy. In this simple case, the implementation of a price increase is assumed to be costless, i.e., $C_1 = 0$, and the energy cost-saving benefit B exceeds the cost C_2 represented by benefits foregone of reduced diesel use at the margin. As a corollary, we also note that, conversely, if energy prices were significantly higher than opportunity costs, then reducing prices and stimulating demand would improve the economic efficiency of energy use. Thus, from the economic viewpoint, conservation need not be always desirable.

The role of price as powerful tool for achieving desirable energy usage levels was stressed earlier. We will also explore here, the other non-price tools such as rationing, physical controls, technical devices, legislation, taxes and subsidies, education and propaganda, etc. for realizing conservation goals. Price and non-price methods for promoting energy conservation are most effective when used in coordinated fashion. The use of non-price and especially technical methods of conservation often require an understanding of the concepts underlying the technical efficiency of energy use. Therefore, we discuss below two technical measures of energy efficiency, and then indicate how they relate to the broader economic efficiency criterion.

Technical Efficiency of Energy Use

The First and Second Laws of Thermodynamics give rise to two distinct definitions for the technical efficiency of energy conservation or use.[1/]

The First Law of Thermodynamics in its simplest form states that energy (i.e., chemical, electrical, gravitational, heat, mechanical, nuclear, etc.) can only be transformed from one form to another, but cannot be created or destroyed. The corresponding first law efficiency of an energy using process may be defined as:

$$e_1 = \text{useful energy output/energy input}$$

Application of this efficiency measure requires definition of the boundaries of the system within which the process occurs, and the determination of energy flows across these boundaries. Consider, for example, the act of heating water in a home using a wood-burning stove as shown in Figure 6.1. Let E_1 be the energy input representing the calorific value of firewood burned, E_0 be the useful energy output absorbed by the water, and E_L be the conductive, convective and radiant heat losses. Then the First Law of Thermodynamics defines the energy balance $E_I = E_0 + E_L$, and

$$e_1 = E_0/E_I = 1 - E_L/E_I \qquad (6.1)$$

Thus the first law efficiency of any process may be determined by correctly identifying all the appropriate energy flows and losses. This type of energy "bookkeeping" may be quite complicated for a complex system such as a thermal electric power station involving flows of many forms of energy including heat, electrical, mechanical and chemical energy.[2/]

1/ The first and second law efficiencies described here are also loosely called the conservation and thermodynamic efficiencies respectively. We will avoid the latter terminology because of the potential for misinterpretation.

2. For details of energy balancing see for example, John E. Ahern, The Exergy Method of Energy Systems Analysis, (New York: Wiley, 1980), pp. 24-30.

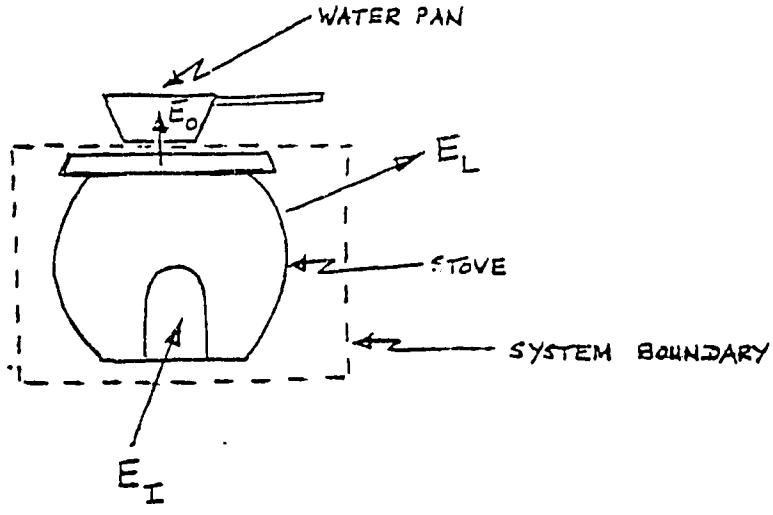

Figure 6.1 Application of First Law Efficiency: Heating Water

Energy balance analysis provides a convenient framework for determining the first law efficiency from primary energy source to final end use, and therefore may be used as one criterion to discriminate between different energy delivery systems.[1/] Consider the example of domestic water heating using either natural gas and electricity, the respective first law efficiency of the processes in the home being about 0.5 and 0.95. Use of electricity appears to be superior. Next, let us take into consideration the first law efficiency of 0.4 for generating electricity from natural gas at the power station, the electricity losses in the transmission and distribution networks of 15%, and the losses in the gas delivery system of 30%.

The first law efficiency of the total chain from gas to hot water via the electric option is given by:

$$e_{1E} = 0.4 \times 0.85 \times 0.95 = 0.323$$

The corresponding efficiency value for direct heating of water using piped gas would be:

$$e_{1G} = 0.7 \times 0.5 = 0.35$$

Now the direct gas option appears to be slightly superior. In conclusion, we note that this simple analysis has neglected many other relevant factors such as convenience of electricity versus gas including substitutability with regard to non-heating energy uses like appliance use, relative costs of the delivered energy, and so on. The influence of these other considerations may be dominant as discussed later in this chapter.

1/ Some advocates of energy analysis take the extreme viewpoint that the desirability of all processes and activities should be assessed on the basis of energy alone. Such an energy theory of value, would seek to establish the relative value of all other goods and services in relation to a numeraire or yardstick based on the energy embodied in them, or required to produce them. Clearly, this elevates energy to the position of the principal scarce resource and would tend to downplay or neglect the value of other productive factors such as labor, land and capital. This could lead to significant misallocation of scarce resources and reduced economic efficiency. See for example: Frank J. Alessio, "Energy Analysis and the Energy Theory of Value", The Energy Journal, Vol. 2, January 1981, pp. 61-74. Further difficulties arise in the application of an energy theory of value and optimization of human activities with respect to energy alone because first law and second law optimization of the same process will not always be consistent. See for example: Donald I. Hertzmark, op.cit. Therefore, energy analysis, energy audits, energy bookkeeping, energy efficiency and energy balance information are best used as a supplement to the economic assessment of conservation measures described later in this chapter.

The Second Law of Thermodynamics seeks to distinguish between energy that is available and unavailable to do useful work. It states that the entropy (or unavailable energy) of a closed system must remain constant or increase over time.[1/] The entropy of a system is closely linked to its state of order. Consider, for example, two glasses of water, one at 100°C and the other at 0°C. By virtue of the temperature difference heat can flow from the hotter to the colder glass and this flow may be used to perform useful work (e.g., using a thermocouple). We note also that the water in this two glass system is ordered into two basic categories: hot and cold.

If we now mix the two glasses of water together and then separate them again so that each glass full will be at a temperature of 50°C (assuming that the system is well insulated and there are no heat losses). By eliminating the temperature differential, we have also eliminated the possibility of heat flow between glasses, and the capability to extract useful work from the system. The system entropy has increased while its state of order has decreased since there is only one category of lukewarm water now available. The total heat context of the system is however unchanged since there were no heat losses. The lower entropy of the original system can be regained only by external use of energy to heat one glass and cool the other. If this occurs the system is no longer closed to the outside world as required by the Second Law definition. Furthermore, the Second Law also ensures that the available energy used externally to restore the two glass system to its original state will always be greater than the available energy which can be reextracted from the system. Thus if the original hot-cold system is restored, the total available energy in the system and its external environment would have decreased further, i.e., total entropy has increased.

1/ This implies that the total entropy of the universe will keep on increasing until a condition of complete thermal disorder known as the "heat-death" is reached.

The second law efficiency may be accordingly defined as:

e_2 = Theoretical Minimum Energy Required/Energy Actually Input

$$= E_M/E_I \qquad (6.2)$$

In the simple case of heat transfer from a heat source to a heat reservoir which is to be heated, E_m is defined by:[1/]

$$E_m = E_0(T_T - T_A)T_T \qquad (6.3)$$

where E_0 is the quantity of thermal energy transferred, T_T is the absolute temperature (in degrees Kelvin) at which the heat is transferred, and T_A is the absolute (ambient) temperature of the reservoir.[2/]

Combining equations (6.1), (6.2) and (6.3), we get:

$$e_2 = e_1 \ (T_T - T_A)T_T = e_1(1 - T_A/T_T) \qquad (6.4)$$

Therefore, an increase in first law efficiency e_1 implies an increase in second law efficiency, and vice-versa, provided the other parameters remain unchanged.[3/] If T_T is high, i.e., $T_T \gg T_A$; then e_2 and e_1 are approximately equal, but if the temperature differential is small, e_2 may be much lower than e_1.

As a numerical illustration, consider a process such as fluidized bed coal combustion to produce electricity where heat is transferred at a very high temperature. The corresponding first and second law efficiencies

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1/ E_M is defined with respect to the ideal Carnot energy cycle between two temperatures. For details, see John E. Ahern, op.cit., pp. 9-10.

2/ Degrees Kelvin (°K) = 273 + Degrees Centigrade (°C).

3/ Examples have been quoted where an increase in e_2 is accompanied by a decrease in e_1. See Donald I. Hertzmek, "Joint Energy and Economic Optimization: A Proposition", The Energy Journal, Vol.2, pp. 75-88, January 1981.

are approximately the same usually lying between 0.4 and 0.45. In contrast, the first law efficiency of a gas furnace used for space heating would lie approximately between 0.75 and 0.8, while the corresponding second law efficiency would be only about 0.05 to 0.1. This large difference is caused by the fact that natural gas which can develop a very high flame temperature (1500 - 2000°C) is being used to supply low quality heat, i.e., the burning gas heats air or water to an intermediate temperature which in turn transfers thermal energy to the living space. The second law efficiency is low because heat is ultimately transferred across a relatively low temperature difference of a few hundred degree K, instead of utilizing the full difference between the flame at, say 1800°K, and the room temperature of 300°K.

The blind application of first law efficiency to a process therefore conceals the fact that high quality energy sources such as fossil fuels which have a great potential to do work at high temperature may be used in relatively low temperature processes like water and space heating or cooling, industrial process steam production, and so on. Second Law efficiency permits better matching of energy sources and uses, so that high quality energy is not used to perform low quality work. Some approximate first and second law efficiencies for typical energy uses or processes are given in Table 6.1.

We note that both First and Second Law efficiencies are increased by cascading energy use. Thus, a working fluid such as steam may be successively utilized in several processes. As the steam cools along the chain of processes the quality of heat desired is matched with the steam temperature at each stage to provide the best efficiency. This point is further discussed in Section 6.3, under Energy Conservation in Industry and Electric Power Generation.

Table 6.1 First and Second Law Efficiencies for Some Typical Energy Uses

	Use	First Law Efficiency	Second Law Efficiency
1.	Electricity Generation or Traction (large scale)	0.9 - 0.95	0.3
2.	Industrial Steam Production	0.85	0.25
3.	Fluidized Bed Electricity Generation	0.4 - 0.45	0.4 - 0.45
4.	Transportation (Diesel Powered)	0.4	0.1
5.	Transportation (Gasoline Powered)	0.25	0.1
6.	Space Heating or Cooling	0.5 - 0.8	0.05
7.	Domestic Water Heating	0.5 - 0.7	<0.05
8.	Incandescent light bulb	0.05	<0.05

6.2 An Economic Assessment of Conservation

The economic concept of efficiency most generally recognizes that energy as a scarce resource should be conserved at a level that maximizes the national welfare. More specifically, in an economy where non energy products and services are correctly priced at their economic value, a simple static model indicates that pricing energy outputs at their marginal opportunity cost would result in energy consumption at welfare maximizing optimal levels. Consumption of the various forms of energy either above or below these optimal levels would be economically inefficient and result in reduced aggregate output.

Therefore, from the viewpoint of economic efficiency, if energy prices are below marginal opportunity costs (MOC), then increasing prices to curtail demand constitutes a desirable or economically justified conservation measure that relies on decentralized market forces. Earlier discussions also indicate that determining the MOC for energy may be quite complicated in a dynamic world where the prices of other products are non-optimal. Non-economic objectives such as raising government revenues or providing subsidized energy for the poor may be used to justify divergence of price from MOC. This in turn may require non-price methods to push energy consumption towards optimal levels. We therefore go beyond this broad pricing policy approach to conservation, and attempt to define below an operational criterion which will establish the economic acceptability of any given conservation measure. We begin by illustrating with the aid of several simple examples, the principal considerations that will determine whether an energy conservation measure is economically justified.

Consider a particular end use for energy such as home lighting. Suppose there is a choice of two distinct types of light bulbs, incandescent and fluorescent, both of which have the same economic cost, same lifetime, and provide light output of the same quality. If the fluorescent bulb uses less electrical energy than the incandescent one, then replacing the latter by the former is a conservation measure that results in an unambiguous improvement in economic (and also technical) efficiency. In this case, using fluorescent bulbs instead of incandescent lamps reduces the economic resources expended to provide the desired output, i.e. lighting. Electrical energy has been conserved, with no change in other economic costs and benefits.

Next, suppose that the fluorescent bulb is more costly to install. There is a trade-off between the higher capital cost of the fluorescent lamp and the greater consumption of kilowatt-hours by the incandescent bulb. The relevant data to determine whether substitution of incandescent bulbs by fluorescent ones is economically justified, is summarized in Table 6.2. At this stage we distinguish between the economic value (or opportunity cost or shadow price, as discussed in chapter V, Integrated Framework for Energy Pricing II) of a good or service, and its market price. The former is relevant to decision-making from a national perspective and the latter is more appropriate from a private individuals viewpoint.

Table 6.2 Physical and Economic Data to Assess the Economic Efficiency of Energy Conservation for Lighting

		Incandescent Bulb	Fluorescent Bulb
Installation Cost (Dineros)	Economic Value (Opportunity Cost)	10.5	32
	Market Price	18	36
Physical Energy Consumption (kwh per year during 2 year lifetime)		40	11
Value of Energy consumption (Dineros per year during 2 year lifetime)	Economic Value (Marginal Opportunity cost) a/	16	4.4
	Market Price b/	12	3.3

a/ Dineros 0.4 per kwh b/ Dineros 0.3 per kwh

The national cost (based on economic values) of using the incandescent and fluorescent bulbs over their two year lifetimes are respectively:[1/]

$$EC_I = 10.5 + 10 + 16 /(1 + r) \text{ and}$$

$$EC_F = 32 + 4.4 + 4.4/(1 + r)$$

Assuming an economic discount rate $r = 0.1$, we find $EC_I = 41.0 > EC_F = 40.4$

1/ The term economic value is used synonymously with opportunity costs or efficiency shadow prices. The discounting procedure converts future costs and benefits into present value terms.

As described earlier in this chapter, an equivalent way of economically assessing the conservation measure is to compare the energy cost saving of dineros (16 - 4.4) = 11.6 per year for two years against the increase in capital costs dineros (32 - 10.5) = 21.5. Therefore we find that $(16 - 4.4) + (16 - 4.4)/(1 + r) > (32 - 10.5)$ which is equivalent to comparing EC_I against EC_F. Therefore the use of fluorescent lightbulbs and associated conservation if energy will improve economic efficiency. However, if $r = 0.2$, $EC_I = 39.8 < EC_F = 40.1$, and the conservation measure is no longer beneficial. This switching effect tends to occur whenever an increase in initial investment costs is traded off against the future cost savings realized by conservation, because a larger discount rate will effectively scale down the present value of energy savings. In general, the impact of the discount rate will be greater if the investment differential is increased and if the expected energy cost savings are larger and extend many years into the future.

This type of economic cost-benefit analysis will help policymakers determine the desirability of a conservation measure. But, the next step of analyzing whether market forces will influence energy users to adopt an economically desirable conservation measure is equally important.

The private cost (based on market prices) of using incandescent and fluorescent lighting respectively, may be assessed using the data in Table 6.2:

$$PC_I = 18 + 12 + 12/(1 + r) \text{ and}$$

$$PC_F = 36 + 3.3 + 3.3/(1 + r)$$

suppose $r = 0.1$, so that $PC_I = 40.9 < PC_F = 42.3$.
Therefore a private individual would prefer to use incandescent lightbulbs, because this is the cheaper option in terms of market prices.

Thus the analysis of data in Table 6.2 points out a situation in which market forces are discouraging consumers from conserving energy and improving both the economic and technical efficiency of energy use. To resolve this anomaly, the first option policymakers might consider would be to raise the market price of electricity from 0.3 dineros per kwh to its economic value of 0.4 dineros per kwh. We now have: $PC_I = 48.5 > PC_F = 44.4$ and rational electricity consumers will make the correct decision in favor of fluorescent lighting. In addition, setting the electricity price equal to its marginal opportunity cost will also establish electricity consumption for non-lighting purposes at optimal levels.

Suppose that public resistance or other social pressures make it impossible to raise electricity prices. Let the economic value of an incandescent bulb be its cost of production or producer price, while the imposition of a government tax of dineros 7.5 determines the market price. Similarly, assume that an import duty of dineros 4 represents the difference in the c.i.f. import cost (dineros 32) and the market price of fluorescent bulbs. Instead of raising electricity prices, an alternative policy option might be to raise the tax on incandescent lightbulbs to dineros 9.5, making the market price dineros 20. In this case, $PC_I = 42.9 > PC_F = 42.3$, which encourages the desirable consumer decision. Reducing the duty on fluorescent bulbs to dineros 2 and lowering the retail price to dineros 34 would also yield a favorable result, since

now: $PC_I = 40.9 > PC_F = 40.3$. Some combination of the tax increase and lowering of duty could also be used. From the general economic viewpoint and ignoring effects outside the lightbulb market, reducing the import duty would be preferable to raising the producer tax because the former action reduces the divergence between market price and economic opportunity cost of fluorescent bulbs whereas the latter has the opposite effect and increases the market distortion in the price of incandescent lightbulbs.

Next, assume that the tax on incandescent lightbulbs cannot be increased because the legislation affects a much larger class of related products. Similarly, suppose that the import duty on fluorescent bulbs cannot be reduced because it would undercut the price of a high cost local producer and drive him out of business. In this instance, some final options left to the energy policymaker might be to legislate that all incandescent lightbulbs be replaced by fluorescent ones, or to give a direct cash subsidy to consumers who adopt the measure, or to mount a major public education and propaganda campaign to bring about the required change.[1/]

We may summarize the steps that an energy policymaker should take before adopting and implementing any given conservation measure. First, using economic opportunity costs consistent with the national viewpoint, he should establish whether the benefits of such an action exceed the costs. If this is the case, then the same test should be repeated using market prices relevant to the appropriate consumer group, to establish whether a

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1/ The evidence concerning the effectiveness of education and propaganda as a energy conservation policy tool is mixed. See for example: James M. Walker, "Voluntary Responses to Energy Conservation Appeals", Journal of Consumer Research, vol. 7, June 1980, pp. 88-92; and A.E. Peck and O.C. Doering, "Voluntarism and Price Response: Consumer Response to the Energy Shortage", The Bell Journal of Economics, vol. 7, spring 1976, pp. 287-292.

rational consumer would adopt the conservation measure. This is unlikely to be the case, because otherwise the conservation measure would already be in use. Therefore, changes in energy prices taxes or import duties on equipment, subsidies to consumers, legislation, and other policy options would have to be used to successfully implement the conservation technique. In general, price changes that reduce the divergence between market prices and opportunity costs would be especially preferred. However, care should be exercised to ensure that these policy actions do not have adverse repercussions in other energy as well as non-energy markets. We discuss next, some complications that could arise in the assessment and application of conservation measures.

If the useful lifetimes of technological alternatives are different, then their economic comparison becomes somewhat more complicated, e.g., in our earlier example, if the lifetime of incandescent bulbs is only one year while fluorescent light last 3 years. Two alternative approaches may be used to overcome this difficulty. In the first, the investment costs of each alternative is annuitized over its lifetime at the appropriate discount rate and the associated energy consumption and other recurrent costs for one year are added on. Then these total costs for each option are compared. The second method is to compare the full costs of each alternative over a long period, say 20 years, including the costs of periodic replacement of worn out equipment.[1/] The two methods should give consistent results, assuming the same values are used for parameters such as the discount rate.

Another type of difficulty associated with changes in the benefits of consumption arises if either the quality or quantity of the end product of energy use is different for the two alternatives. As an example of the first

1/ Strictly speaking the discounted scrap value of equipment left at the end of the 20 year period should also be deducted from the costs stream associated with the corresponding alternative.

effect, consider a comparison of electric versus kerosene lamps for lighting. In addition to the differences in equipment and fuel costs, the cost-benefit assessment of the two options should also include a term to recognize that electricity is likely to provide lighting of a superior quality.[1/] While the quantification of this qualitative superiority in monetary terms will be difficult, one measure might be the willingness-to-pay of the consumers for the different forms of lighting, usually represented by the area under the relevant demand curve.

An example of the quantity effect might be the physical rationing of gasoline. In this case, the cost or welfare loss to the consumer due to the reduction in the miles he may travel in his car should be added to the cost of implementing the rationing scheme and then compared with the benefit of reduced gasoline supply. Once again, the willingness-to-pay of gasoline users would be the appropriate measure of the foregone consumption benefit. In contrast,

the appropriate measure of the foregone consumption benefit. In contrast,

we note that the introduction of a more fuel efficient automobile engine can conserve gasoline without reducing miles travelled. Therefore a reduction in energy consumption does not always imply reduced consumption benefits. The focus should be on the service derived from the energy use.

Finally, the costs and benefits associated with externalities should be included in the economic cost-benefit comparison of alternatives. For example, improvements in technical efficiency or fuel substitution measures may give rise to pollution, as in the case of converting from oil burning to coal fired electric power generation. The effect of sunk costs should also be recognized. Thus,

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1/ The ease and convenience of handling of a fuel, danger from its use, social acceptability, and so on, are all factors that may affect the consumers choice. See for example, the Thai case study chapter: use of energy for tabacco curing.

using our earlier example, if the oil burning generating plant already exists, the initial comparison should allow for the fact that the oil option has no associated capital costs until that plant is fully depreciated physically.

6.3 Conservation Opportunities in Energy Producing and Using Sectors 1/

Aggregate economy-wide measures such as the ratio of energy use to value added or GDP are not very helpful in determining specific policies to improve the energy situation. The practical application of energy conservation policies requires the disaggregate analysis of the technical, economic and behavioral relationship underlying the various types of energy conversion and end-use. In this section, we attempt to summarize the principal practical possibilities for energy conservation in the near term in several selected energy producing and consuming sectors of the economy, based on the recent experience of both industrialized and developing countries. Since the emphasis here is on conservation, mention of improvements in efficiency generally refers to increases in the first law efficiency of energy use that will yield actual reductions in energy inputs required to perform a particular task. It is also understood that the desirability of adopting any conservation measure must depend on the economic criteria discussed in the previous section, and on the social, political, overall physical and other constraints peculiar to the country concerned.

1/ General references which explore in greater detail some of the aspects discussed in this section include: Richard C. Dorf, Energy Resources and Policy, (Reading, Mass: Addison-Wesley Publ. Co., 1978); Energy Programs and Policies of IEA Countries, 1977 Review, OECD, Paris; ibid 1978 Review; ibid., 1979 Review; ibid., 1980 Review; John C. Sawhill (editor), Energy Conservation and Public Policy, (Englewood Cliffs, N.J.: Prentice-Hall, Inc., 1979); and Sam Schurr, et. al., Energy in America's Future, (Baltimore: Johns Hopkins Univ. Press, 1979).

Transportation

The principle purpose of a transportation system is to physically convey people or goods from one location to another. Therefore, any measure which increases the payload in terms of energy used per passenger-mile or ton-mile would help the conservation effort. Important methods of achieving this result include: (a) changing from more to less energy intensive transport modes; (b) increasing the technical efficiency of energy use of given modes of transportation; and (c) changes in behavior and overall systems effects. We will examine each of these three aspects, below:

Table 6.3 summarized some typical characteristics of the chiefly used transport needs. The energy intensity figures for a given mode will vary widely depending on the geographic characteristics, goods transported, behavioral characteristics, and so on. However, even on a rough basis, it may be seen that switching modes could provide substantial savings. For example, a change from passenger-car travel to mass transit modes such as bus or rail, or a transition from freight-trucks to freight-trains would reduce fuel consumption. In a period of rapidly rising petroleum prices, conservation in the principally liquid fuel using road transport mode should have a high priority. In particular, savings in traffic congestion costs in urban areas and also reductions in air pollution may be significant. However, behavioral, physical and other impediments such as the unwillingness of motor car owners to use public transport, or the inaccessibility of railway stations for freight hauling will make it difficult to effect these changes.

Table 6.3

Typical Energy Use Characteristics of Principal Transport Modes (1975-80)

Mode	Energy Intensity Btu/Passenger Mile	Energy Intensity Btu/Ton Mile	Share of Energy Consumption[1/] Industrialized Country[3/]	Share of Energy Consumption[1/] Developing Country[4/]
Walking/Bicycle/Animal[2/]	300- 500	-	< .01	.05
Pipeline	-	300- 600	.05-.1	<.05
Water	-	400- 700	<.05	.05-.1
Railway	2,000-3,000	500- 900	<.05	<.05
Bus	1,000-1,500	-	.01-.1	.05-.1
Truck	-	1,500- 2,000	.1 -.2	.35-.45
Car	2,000-4,000	-	.4 -.5	.25-.35
Air	5,000-9,000	15,000-25,000	.05	.05

1/ As a fraction of total commercial energy consumption.

2/ Non-commercial energy use given as a fraction of commercial energy total.

3/ Source: Author's estimates and OECD, IEA and USDOE data.

4/ Source: Author's estimates and "Energy in the Developing Countries", The World Bank, Washington, D.C., August 1980.

The technical efficiency of energy use may be increased by introducing more fuel efficient engines, improving the quality of roads, electrifying railways, and so on. A combination of price, legislation and government investments or other initiatives can be used effectively.

Behavioral changes include car-pooling, getting people to live closer to their place of work, using alternative methods of communication like telephones where possible, and so on. In many cases people may be very resistant to adopt these changes in lifestyles, many of which affect the whole socio economic system rather than the transportation system alone (e.g.,urban living patterns, travel and migration patterns etc.). In the developing countries some of the developmental changes themselves may encourage shifts to move energy intensive and modern modes, e.g., use of motor vehicles instead of walking, bicycles or animal drawn carts. Therefore, the desirability of any conservation policy must be assessed against the overall economic criterion discussed earlier. Coordinated use of price and non-price tools are again important. For example, public exhortations alone are unlikely to be effective.

Building, Lighting, Space Heating and Cooling

Three factors affect the consumption of energy in buildings: (a) behavioral characteristics and attitudes of occupants; (b) energy using equipment installed; and (c) architechtural design practices and material used. Keeping living and working space lighted and cool are the chief concerns in the tropics where most of the developing countries lie. In these areas the use of air-conditioning is growing rapidly for commercial buildings such as businesses,

tourist hotels, etc., and to a lesser extent for residences of upper income urban and expatriate groups whose numbers are fortunately small in this respect. In the industrialized countries, which are located more in the temperate and colder zones, lighting and both space heating and cooling are required.

The principles that govern the application of energy conservation practices remain the same. Thus the full range of policy tools including increases in energy prices, legislation, tax incentives, and so on will help to implement conservation measures. However these policies and their consequences must be simple and easily comprehensible. Educating occupants of building (especially domestic residents) concerning simple conservation practices, making them aware of new but readily available energy saving devices, and explaining the consequences of new pricing structures and taxes should have a high priority. The so-called "information gap" is particularly critical in this area of conservation.

Changes in behavior and attitudes often take time to occur. For example, admonitions to switch off unused lights or set back thermostats may take years to sink into the public consciousness especially if these requests run up against false but commonly held beliefs. Thus in Indonesia, where a fixed charge lifeline electricity tariff was in effect, low income households were found to be using their lightbulbs as many as 16 hours a day. This occurred despite an energy conservation campaign, because it was widely believed that switching lights on and off would reduce their lifetime more than if the bulbs were kept continuously lighted, while the electricity bills were fixed and unrelated to kilowatt-hour consumption.

In other cases, people are unwilling to give up comforts they have grown accustomed to, unless some costs are involved. Thus requests to set back thermostats in many industrialized countries have not been effective except when accompanied by increased energy prices, and only after the effect of increased energy bills were felt. Public resistance may also occur in developing countries where people who are just beginning to enjoy the benefits of economic growth resent being asked to cut back on consumption of electricity for lighting, air-conditioning, and so on. Pricing of energy at economic opportunity cost is very useful in all these cases, because the consumers can get the correct price signal and then choose how much energy to use on the basis of willingness-to-pay. Even then responses to price changes could be slow because these adjustments in energy usage patterns may imply major expenditures for purchasin new energy using equipment as discussed below. In brief, behavior changes that facilitate conservation may be realized only slowly, and policymakers should fully investigate local attitudes and idiosyncracies with respect to energy use patterns.

Improvements in energy using equipment and appliances in buildings are an obvious target for conservation programs. Thus occupants must be made aware of the many opportunities for replacing inefficient equipment such as furnaces and air-conditioners, retrofit or improvements to existing equipment, or simply improved operation and maintenance procedures. Appropriate financial incentives should be provided to reinforce the message. Technical advice, energy audits and guidance could be provided by the government, especially in tha case of large buildings e.g., some of the modern heating and cooling systems are very effective, using an array of techniques ranging from heat pumps to computerized control of equipment in different parts of the building.

Legislation on minimum energy efficiency standards for equipment and appliances is also helpful.

As mentioned earlier, the high cost of replacing old equipment may delay consumer response to higher energy price signals. For example, the lump sum cost of a new refrigerator may be a significant fraction of income, thus causing the consumer to wait until his old inefficient refrigerator is worn out before replacing it. Replacing incandescent lightbulbs with fluorescent fittings is another energy saving measure whose costs may deter a poor consumer. This phenomenon is particularly significant in developing countries where incomes are low and the fuel may be relatively cheap or subsidized (relative to its shadow price). For example, several programs are under way to replace open hearth fires whose first law efficiency is only about 5% with simple stoves that are over four times as efficient. These have had limited success, and only when government officials provided the improved stoves free or at a subsidized price, coupled with a strong promotion campaign. In all these cases, financial incentives or subsidies on new equipment could be most effective. Thus energy saving improvements in equipment will be realized quicker in general, with the combined use of higher prices, legislation, public education and equipment subsidies.

Architectural design, building practices and construction materials used is the third area in which energy conservation gains may be made[1/].

1/ See for example: G. Dallaire, "Designing Energy Conserving Buildings", Civil Engineering, April 1974, pp. 54-8.

Policymakers may make a significant impact by altering building codes and implementing legislation relating to minimum efficiency standards. The orientation of buildings, location of windows, type of glass used, and other architectural features can improve heat losses. Use of improved insulating materials and high standards of construction to avoid flaws or gaps in insulation are also helpful.[1/] If buildings are not completely enclosed as in some developing countries, proper design will promote natural air circulation. Use of simple local materials such as brick tiles (instead of asbestos), higher ceilings and installation of fans are often substitutes for air conditioning in the tropics. Much can be achieved in the way of conservation by a well informed and imaginative architect.

Industry

Improvements in the efficiency of industrial energy use cover such a broad range of techniques that only the general principles can be touched on here. Contrary to widespread belief, many industries are unaware of increases in efficiency that can be realized quite simply and are extremely cost effective. Because the concentrated nature of industrial energy users, both governments as well as energy suppliers and utility companies can be particularly effective in legislating improvements, counselling, providing energy audits and helping consumers carry out technical improvements. Three broad areas for conservation

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1/ There are practical limits to conservations gains that may be achieved in this respect. Thus, improving construction practices or using better building materials will become increasingly costly and beyond a certain point they would not justify the reduction heat losses, according to the economic criterion described earlier. Again, a perfectly air-tight and insulated building may be ideal from the viewpoint of energy efficiency, but would be stifling and uncomforable to occupants, impose health hazards due to stale or polluted air being constantly recirculated and so on. In brief, savings due to energy conservation must be weighed against the both quantifiable and sometimes non-quantifiable costs incurred.

are: (a) waste heat recovery and cogeneration; (b) other retrofits and improvements in operation; (c) major changes in manufacturing processes and production methods; and (d) recycling and recovery of waste materials. We will briefly examine each topic in turn.

Most large industries use energy for heating and a significant fraction of this thermal energy is expelled into the external environment at temperatures well above ambient conditions, usually in the form of hot gases, steam, or water. This waste heat can be harnessed in a number of ways, thus improving the overall efficiency of energy use in the plant by as much as 30%. In completely integrated or total energy systems (also called cogeneration systems), fuel would be used to generate electricity, yield process heat for industrial use, heat buildings in the area (i.e., district heating), provide hot water, process solid and liquid wastes, and so on. A central concept in this type of system is that the overall efficiency of energy use for the total plant be maximized rather than the efficiency of any single component or sub-system such as electricity generation.[1/] In fact the energy efficiency of certain components may have to be reduced below what it would have been if it was operating on its own. The gains in other parts of the system more than compensate for this loss, and thus overall efficiency improves. For example, the exhaust heat from an electric power generator in a cogeneration scheme would be extracted at a somewhat higher temperature than a stand-alone unit, with consequent loss of power output. However, the waste

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1/ See for example: P. Bos, et al., The Potential for Cogeneration Development in Six Major Industries by 1985, FEA Report, Resource Planning Associates, Cambridge, Mass., 1977.

heat could be used much more efficiently in another task because it is available at a higher temperature.

The best potential for development of cogeneration or total energy systems occurs when new industrial plants are being set up. Many examples of cogeneration exist already in Europe, and the U.S. is not for behind.[1/] There is also considerable scope for such schemes in large industrial estates being set up in many developing countries. In many cases, legal and institutional barriers to agreements that facilitate the exchange of energy between different entities such as utility companies, industries and municipalities, appear to pose greater difficulties than technical constraints. Energy policymakers should take action to smooth out these problems. In the case of existing industries where major changes in plant layout are not possible, there is still scope for more limited use of waste-heat. For example, an industrial plant using steam for heating could also run an auxiliary generation to produce electricity, or hot exhaust gases could be used for drying industrial materials, preheating incoming air, and so on.

The effectiveness with which waste heat can be put to use depends on several factors including the temperature of the exhaust and the degree of compatibility with the quality of heat required in the particular application (as discussed in Section 6.1, under Second Law Efficiency), the availability of sufficient quantities of waste heat to achieve economies of scale, and the distance between the source of the waste heat and its final use.

1/ See for example: L. Schipper and A.J. Lichtenberg, "Efficient Energy Use and Well-Being: The Swedish Example", Science, Dec. 3, 1976, pp. 1001-12.

In general, the higher the temperature of the exhaust fluids, the more efficiently it can be used based on the thermodynamic concept of cascading (see Section 6.1). Some industrial activities that produce waste heat at different temperatures are presented in Table 6.4.

TABLE 6.4 SOURCES OF WASTE HEAT BY TEMPERATURE RANGE

High Temperature		*Medium Temperature*		*Low Temperature*	
Source	*Temperature (°F.)*	Source	*Temperature (°F.)*	Source	*Temperature (°F.)*
Nickel refining furnace	2500–3000	Steam boiler exhausts	450–900	Process steam condensate	130–190
Aluminum refining furnace	1200–1400	Gas turbine exhausts	700–1000	Cooling water from:	
Zinc refining furnace	1400–2000	Reciprocating engine exhausts	600–1100	• Furnace doors	90–130
Copper refining furnace	1400–1500	Reciprocating engine exhausts (turbo charged)	450–700	• Bearings	90–190
Steel heating furnaces	1700–1900	Heat treating furnaces	800–1200	• Welding machines	90–190
Copper reverberatory furnaces	1650–2000	Drying and baking ovens	450–1100	• Injection molding machines	90–190
Open hearth furnace	1200–1300	Catalytic crackers	800–1200	• Annealing furnaces	150–450
Cement kiln (Dry process)	1150–1350	Annealing furnace cooling systems	800–1200	• Forming dies	80–190
Glass melting furnace	1800–2800			• Air compressors	80–120
Hydrogen plants	1200–1800			• Pumps	80–190
Solid waste incinerators	1200–1800			• Internal combustion engines	150–250
Fume incinerators	1200–2600			Air conditioning and refrigeration condensers	90–110
				Liquid still condensers	90–190
				Drying, baking, and curing ovens	200–450
				Hot processed liquids	90–450
				Hot processed solids	200–450

Source: W. M. Rohrer and K. Kreider, "Sources and Uses of Waste Heat," *Waste Heat Management Guidebook*, NBS Handbook 121 (Washington, D.C.: Government Printing Office, January 1977), p. 5.

The second broad area for encouraging conservation is in the improved operation of existing plant and by appropriate retrofits. Adapting old equipment for cogeneration is of course also a form of retrofitting, but this has been discussed earlier. There are many other ways in which the energy efficiency of industrial processes may be improved. For example, the thermal insulation or lagging of boilers and pipes carrying heating or cooling fluids may be increased, the mixing of fuel and air could be improved to provide better combustion, heat transfer can be enhanced, and so on. More sophisticated techniques such as computerized control of industrial processes can also increase conservation. In many cases, detailed energy audits by external experts can pinpoint these improvements, identify new energy efficient devices that are readily available, and demonstrate the cost effectiveness of such conservation practices to the industrialists concerned.

The third aspect of conservation involves major changes in industrial activity. Shifts in technology and production processes most often occur in response to changes in the relative prices of energy and other inputs such as capital and labor. Thus, an increase in the real cost of energy would favor a shift towards a less energy intensive technology. We note that autonomous technological improvements can also occur quite independently and sometimes contrary to price changes, due to inventions that improve the efficiency of industrial processes. For example, in the case of aluminum smelting which is one of the most energy intensive industrial processes, the electricity requirements for smelting a kilogram of aluminum from bauxite ore decreased from about 26 kilowatt-hours in 1940 to about 17 kilowatt-hours by 1975 despite an overall

decrease in the real price of electricity. With the added impetus of higher energy costs, a new chlorine process now being introduced will decrease energy consumption to about 10 kilowatt-hours per kilogram of aluminum.[1/] More generally, the energy inputs per dollar of industrial value added in the U.S. decreased from about 110,000 Btu to 80,000 between 1945 and 1975. Appropriate price signals regarding higher energy costs and incentives to encourage research and development to improve the energy efficiency of major industrial production processes are important tools in the conservation specialists arsenal.

While the bulk of manufactured products are derived from the processing of raw input materials, the recycling of previously manufactured but discarded materials may be less energy intensive. The difficulties of collecting and sorting waste materials prior to recycling could significantly increase processing costs especially where labor inputs are required to do this. Some typical figures for energy saving through recycling are given in Table 6.5

Table 6.5 Energy Savings From Recycling (1978)

Material	Share of Energy Costs in Value of Output	Energy Use for Processing (Kwh/kg) From Raw Material	Energy Use for Processing (Kwh/kg) From Waste Material	Energy Saving (%)	Chief Constraints
Glass	0.35	2.3	2.3	None	Collection
Paper	0.35	1.9	0.95	50	Separation
Steel	0.35	13.4	6.6	50	Impurities, separati and collection
Plastics	0.05	13.0	0.58	95	Technology commercially unavailable

1/ Richard A. Charpie and Paul W. McAvoy, "Conserving Energy in the Production of Aluminum", Resources and Energy, vol. 1, September 1978, pp. 21-42. A minimum value for energy use of about 8 kilowatt-hours per kilogram of aluminum based on thermodynamic limits has been estimated in: Elias P. Gyftopoulos, J. Lazaros, J. Lazaridis and Thomas F. Widmer, Potential Fuel Effectiveness in Industry, (Cambridge, Mass.: Ballinger, 1974).

Electric Power

Electric power is a relatively mature energy sub-sector where conservation techniques are well developed, and this permits us to clearly illustrate the links between energy conservation, demand management and pricing. The three principal opportunities for conservation arise in the (a) generation; (b) transmission and distribution; and (c) efficiency and patterns of end use of electricity.

Conservation gains in the production of electricity may be achieved through efficiency improvements in individual generating plants or with respect to the whole power system.[1/] In the former category, efficiency improvements in generation technology have occurred steadily over the last fifty years or more. Many of these advances have stemmed from economies of scale as unit sizes of generators have increased. For example, the largest steam units of about 200 MW available in 1930 had first law efficiencies of less than 20%, while the largest unit size for today's thermal plant is about 1,500 MW and they operate at much higher steam pressures and temperatures to achieve first law efficiencies of about 35-40%. New technologies such as fluidized bed combustion and magneto-hydrodynamic generation could improve this figure substantially in the future, but thermodynamic laws will limit ultimate efficiencies to around 55%.

In the case of large modern hydroelectric generating units, the hydrostatic or potential energy of stored water are already converted into

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1/ Switching some generation where possible from fossil fuels to renewable and new sources such as solar wind and wave power can conserve depletable energy resources. The possibilities are extremely country specific and depend on resource endowments.

electrical energy at efficiencies exceeding 90% and the scope for improvement is somewhat more limited. Retrofitting of existing thermal and hydro plant, and improving operating and maintenance procedures to at least bring them up to original design standards is another area for conservation. The cogeneration type arrangements discussed earlier under industrial energy conservation will also improve efficiency. While introducing new plant is likely to be highly capital intensive, the alternative of upgrading of existing units is so case specific that high inputs of skilled manpower will be required. The cost effectiveness and desirability of these various options will have to be established case by case accordingly to the overall economic criterion outlined in Section 6.2.

System wide improvements in the efficiency of producing electricity can also be achieved by correctly matching the available technology to the pattern of demand. As explained in greater detail in chapter 8, Introduction to Investment Planning, meeting a certain shape of load duration curve at the least possible cost requires optimal long-range planning and operation of the power system. For example, the least cost generation planning of an all thermal system implies that steam or nuclear plants should be built for base load duty (i.e. operating at least 6,000 out of 8,760 hours per year) because their fuel costs are low although their investment costs are high. The same logic dictates that gas turbine units which have low capital costs but high fuel costs should be used for peak period operation, usually about 2,500 hours per year. Similarly, in optimal system operation and load despatch, the available generating plant is used sequentially starting with

the newer base load units that are cheapest to run and ending with old or peaking units that have the highest fuel costs. Many electric utilities offer scope for improvements in system efficiency, especially in many developing countries where engineering-economic optimization of system planning and operation is neglected or poorly done.

Conservation in the delivery of electric power is achieved by reducing technical losses in the transmission and distribution (T&D) networks. These losses may be as high as 30% of gross generation in some developing countries, although norms in industrial countries are about 10%. The determination of optimal or desirable loss levels are based essentially on the trade-off between the increased capital costs of augmenting T&D capacity, and the corresponding savings in both kilowatt and kilowatt-hour losses. The rapid increases in the costs of electricity supply in the 1970's indicate that the levels of losses previously considered desirable are likely to be unacceptably high today. As shown in Figure 6.2, the optimal trade-off occurs when total costs defined as the costs of losses plus the system investment and operation and maintenance costs (all in present discounted value terms over a long period of about 10-20 years) are minimized.[1/] The desirable loss level shifts from L_L to L_H as energy costs rise. Losses due to theft can also be significant, reaching levels of 10-15% in some developing countries. U.S. norms are about 2-3%. Such losses may be reduced by appropriate improvements in legislation and management of the power utility.

1/ We note that as system losses decreases, the quality of electricity supplied may also improve (e.g., better voltage and fewer supply interruptions or outages). Therefore, some adjustment to total costs defined above, may be required to account for the accompanying change in consumption benefits due to improved quality. There is no consumption change due to loss reduction because these losses were not consumed originally, in any case.

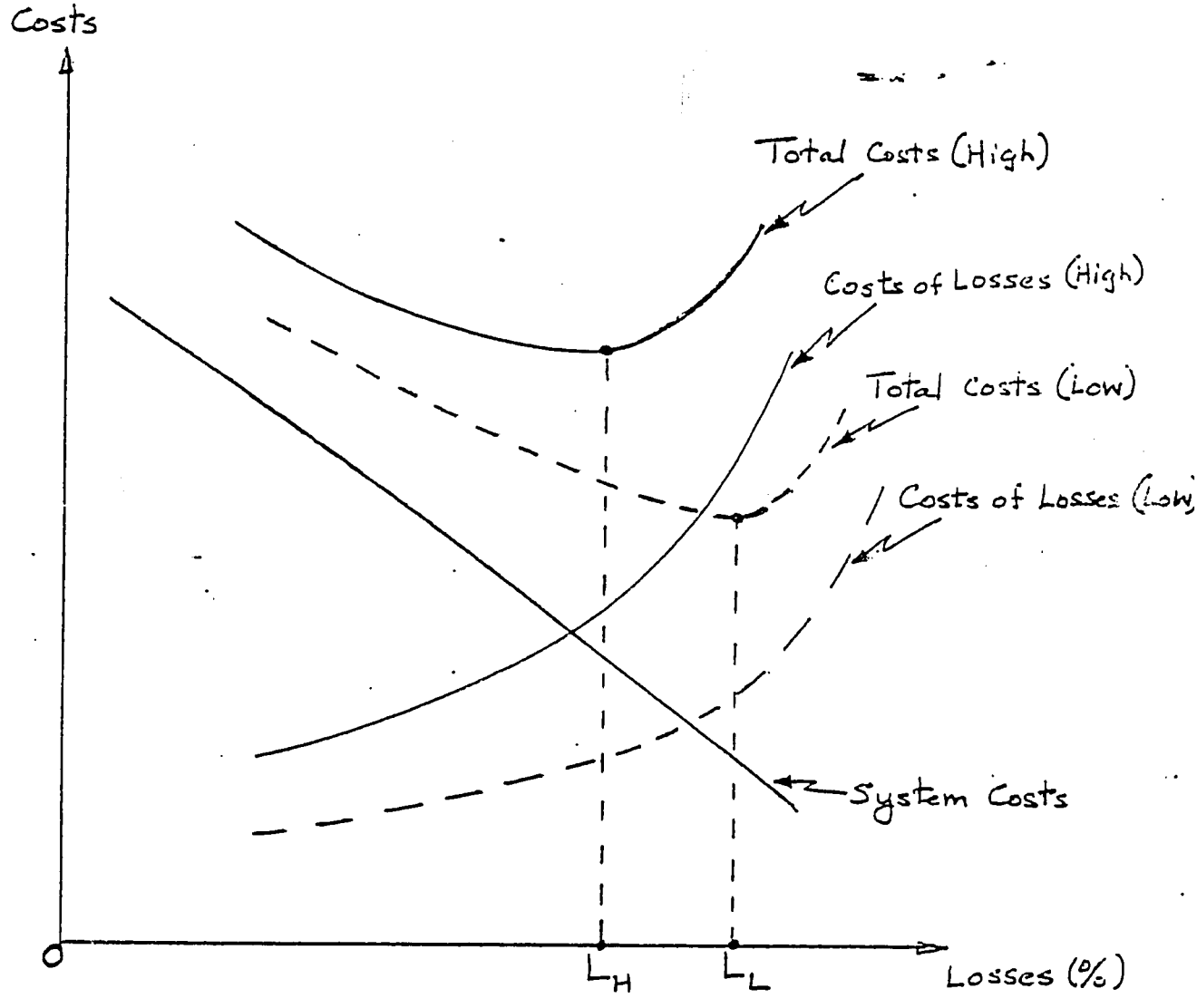

Figure 6.2 Optimal Trade-off Between Losses and System Costs for Electricity Transmission and Distribution Systems.
Total Costs = Costs of Losses + System Costs

Energy conservation at the end use stage may be achieved by two principal methods: improving the technical efficiency of energy using devices and appliances, or changing the shape or characteristics of the load through demand management techniques. The first aspect, increasing the energy efficiency of devices and appliances, has already been discussed in the sections on energy conservation in buildings and industry. The second aspect, uses demand management as a tool to conserve energy and increase the economic efficiency of energy use. In the electricity sector the term load management is used synonymously with demand management. Because of the relative sophistication and maturity of this sector, load management techniques are well developed and fall into two basic categories: soft load management which relies on prices, financial incentives and public education to achieve voluntary changes in consumer electricity use patterns; and hard load management which seeks to realize the same result by actual physical control of consumer loads.

It is more costly to supply electricity during certain seasons or hours of the day known as peak periods than during other off-peak periods. Therefore changing the shape of the power utility's load curve by shifting electricity consumption from peak to off-peak periods will reduce the costs of supply and conserve energy. Charging higher prices (equal to long run marginal costs) during peak time-of-day or seasonal periods signals the consumer that he should try to switch at least some of

his load to off-peak periods.[1/] Separate capacity and energy changes may also be used. Providing financial incentives to retrofit old equipment, improve power factor (by adding a capacitor bank), and so on, are also soft demand management techniques.

The clearest example of hard load management is the case of interruptible loads, where certain industrial consumers receive cheap power but may be cut-off or shed at short notice when the total system load approaches the available capacity (during peak periods). Domestic loads such as water heaters can also be controlled through ripple control or radio by the utility. Within the next decade, advances in solid state hardware and metering will allow greater control and switching of individual loads through use of microprocessors, and so on.

1/ For details of peak load pricing, see Mohan Munasinghe, Principles of Modern Electricity Pricing, Proc. IEEE, March 1981. Shifts from peak to off-peak consumption result in an increase in the load factor. However, from an economic efficiency point of view the objective of load management is not to achieve a load factor of 1.0, but to see as far as possible that the price or consumers willingness-to-pay (i.e., benefit) equals the marginal cost of supply at all times.

6.4 Conservation and the Environment

Much has been written regarding the relationship between energy and the environment. We begin this section by noting that the economic criterion for conservation described in Section 6.3 seeks to include environmental gains and losses wherever these can be identified, in the cost-benefit analysis, so that the desirability of a conservation measure is judged in relation to its environmental impact. This is important because different energy conservation practices can either improve or worsen the environment.

In the case of automobile exhaust emission, pollution limiting devices will generally decrease fuel efficiency. Therefore, there is a conflict between the conservation and environmental objectives, requiring the trading-off of various gains and losses, preferablly in the economic framework discussed earlier. Where quantification of environmental costs and benefits is difficult, judgement must be used. On the other hand reducing the use of fuelwood in certain developing countries may prevent severe deforestation problems, with associated environmental consequences such as soil erosion, loss of vegetation, reduced watershed potential, and so on. Thus conservation of fuelwood is consistent with the ecological goal, but may involve other costs such as substitution of a more expensive commercial fuel for firewood. Once again, an economic analysis provides the basis for rational decision making.

CHAPTER III

POWER TARIFFS

DEMAND MANAGEMENT POLICIES:

IIb. Principles of Integrated Energy Pricing

and

IIIb. Application and Impact of Pricing Policy

ELECTRIC POWER 1/

by

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Introduction and Overview

Modern societies have become increasingly dependent on various types of energy sources, among which electric power has occupied a dominant position. Traditionally, electric power pricing policy in most countries has been determined mainly on the basis of financial or accounting criteria, e.g., raising sufficient sales revenues to meet operating expenses and debt service requirements while providing a reasonable contribution towards the capital required for future power system expansion.

However, in recent times several new factors have arisen, including the rapid growth of demand, the increase in fuel oil prices and prices of fossil fuel and nuclear plant, the dwindling availability of cheaply exploitable hydro-electric resources, and the expansion of power systems into areas of lower consumer density at relatively high unit costs. These developments have led to increasing emphasis being laid on the use of economic principles in order to produce and consume electric power efficiently, while conserving scarce resources, especially in the developing country context. In particular, a great deal of attention has been paid to the use of marginal cost pricing policies in the electric power sector.

1/ The views expressed in this paper are the author's. and not necessarily those of the World Bank.

The objectives of power tariff policy in the national context, and a pricing framework based on long run marginal costs (LRMC) which meets these requirements, are summarized in this section. In Section B, the economic principles underlying the LRMC approach are described, and in Section C, a framework for calculating strict LRMC is presented. Finally, the process of adjusting LRMC to devise a practical tariff structure which meets other national constraints is discussed in Section D, followed by several technical appendices.

A.1 Requirements of a Power Tariff

The modern approach to power pricing recognizes the existence of several objectives or criteria, not all of which are mutually consistent. First, national economic resources must be allocated efficiently, not only among different sectors of the economy, but within the electric power sector itself. This implies that cost-reflecting prices must be used to indicate to the electricity consumers the true economic costs of supplying their specific needs, so that supply and demand can be matched efficiently.

Second, certain principles relating to fairness and equity must be satisfied, including: (a) the fair allocation of costs among consumers according to the burdens they impose on the system; (b) the ensuring of a reasonable degree of price stability and avoiding large fluctuations in price from year to year; and (c) the provision of a minimum level of service to persons who may not be able to afford the full cost.

Third, the power prices should raise sufficient revenues to meet the financial requirements of the sector, as described earlier. Fourth, the power tariff structure must be simple enough to facilitate the metering and

billing of customers. Fifth and finally, other economic and political requirements must also be considered, e.g., subsidized electricity supply to certain sectors to enhance growth, or to certain geographic areas for purposes of regional development.

Since the above criteria are often in conflict with one another, it is necessary to accept certain trade-offs between them. The LRMC approach to price setting described below has both the analytical rigor and inherent flexibility to provide a tariff structure which is responsive to these basic objectives.

A.2 Long Run Marginal Costs (LRMC) Based Tariffs

A tariff based on LRMC is consistent with the first objective, i.e., the efficient allocation of resources. The traditional accounting approach is concerned with the recovery of sunk costs, whereas in the LRMC calculation it is the amount of future resources used or saved by consumer decisions which is important. Since prices are the amounts paid for increments of consumption, in general they should reflect the incremental cost thereby incurred. Supply costs increase if existing consumers increase their demand or if new consumers are connected to the system. Therefore, prices which act as a signal to consumers should be related to the economic value of resources to be used in the future, to meet such consumption changes. The accounting approach which uses historical assets and embedded costs implies that future economic resources will be as cheap or as expensive as in the past. This could lead to over-investment and waste, or under-investment and the additional costs of unnecessary scarcity.

In order to promote better utilization of capacity, and to avoid unnecessary investments to meet peak demands (which tend to grow very rapidly), the LRMC approach permits the structuring of prices so that they vary according to the marginal costs of serving demands:

- by different consumer categories;
- in different seasons;
- at different hours of the day;
- by different voltage levels;
- in different geographical areas; and so on.

In particular, with an appropriate choice of the peak period, structuring the LRMC based tariffs by time-of-day generally leads to the conclusion that peak consumers should pay both capacity and energy costs, whereas off-peak consumers need to pay only the energy costs. Similarly, analysis of LRMC by voltage level usually indicates that the lower the service voltage, the greater the costs imposed on the system by consumers.

The structuring of LRMC based tariffs also meets sub-categories (a) and (b) of the second (or fairness) objective. The economic resource costs of future consumption are allocated as far as possible among the customers according to the incremental costs they impose on the power system. In the traditional approach, fairness was often defined rather narrowly and led to the allocation of (arbitrary) accounting costs to various consumers. Because the LRMC method deals with future costs over a long period, e.g., about 10 years, the resulting prices (in constant terms) tend to be quite stable over time. This smoothing out of costs over a long period is especially important because of capital indivisibilities or lumpiness of power system investments.

The use of economic opportunity costs (or shadow prices, especially for capital, labor, and fuel) instead of purely financial costs, and the consideration of externalities whenever possible, also underline the links between the LRMC method and efficient resource allocation.

The development of LRMC based tariff structures which also meet the other objectives of pricing policy mentioned earlier, are discussed below.

A.3 Practical Tariff Setting

The first stage of the LRMC approach is the calculation of pure or strict LRMC which reflect the economic efficiency criterion. If price was set strictly equal to LRMC, consmers could indicate their willingness-to-pay for more consumption, thus signalling the justification of further investment to expand capacity.

In the second stage of tariff setting, ways are sought in which the strict LRMC may be adjusted to meet the other objectives, among which the most important one is the financial requirement. If prices were set equal to strict LRMC, it is likely that there will be a financial surplus. This is because marginal costs tend to be higher than average costs, during a period when the unit costs of supply are increasing. In principle, financial surpluses of the utility may be taxed away by the state, but in practice the use of power pricing as a tool for raising central government revenues is usually politically unpopular and rarely applied. However, such surplus revenues can also be disposed of in a manner which is consistent with the other objectives. For example, the connection charges can be subsidized without violating the LRMC price, or low income consumers could be provided with a subsidized block of electricity to meet their basic requirement, thus satisfying socio-political objectives. Conversely, if as in some cases,

marginal costs are below average costs (e.g., due to economies of scale), then pricing at the strict LRMC will lead to a financial deficit, which will have to be made up, for example, by higher lump sum connection charges, flat rate charges, or even government subsidies.

Another reason for deviating from the strict LRMC arises because of second-best considerations. When prices elsewhere in the economy do not reflect marginal costs, especially in the case of substitutes and complements for electric power, then departures from the strict marginal cost pricing rule for electricity services would be justified. For example, in rural areas alternative energy may be available cheaply in the form of subsidized kerosene and/or firewood. In this case, pricing electricity below the LRMC may be justified, to prevent excessive use of the alternative forms of energy. Similarly, if incentives are provided for the importation of private generators, while their fuel is also subsidized, then charging the full marginal cost to industrial consumers may encourage them to purchase captive power plant, which is economically less efficient from the national viewpoint. Since the computation of strict LRMC is based on the power utilities' least cost expansion program, LRMC may also need to be modified by short term considerations if previously unforeseen events render the long run system plan sub-optimal in the short run. Typical examples include a sudden reduction in demand growth and a large excess of installed capacity which may justify somewhat reduced capacity charges, or a rapid increase in fuel prices, which could warrant a short term fuel surcharge.

As discussed earlier, the LRMC approach permits a high degree of tariff structuring. However, data constraints and the objective of simplifying metering and billing procedure usually requires that there should be

a practical limit to differentiation of tariffs by: (a) major customer categories (e.g., residential, industrial, commercial, special, rural etc.); (b) voltage levels (e.g., high, medium and low); (c) time-of-day (e.g., peak, off-take); (d) geographic region, etc. Finally, various other constraints also may be incorporated into the LRMC based tariff, such as the political requirement of having a uniform national tariff, subsidizing rural electrification, and so on. However, in each case, such deviations from LRMC will impose an efficiency cost on the economy.

A.4 Summary

To summarize, in the first stage of calculating LRMC, the economic (first best) efficiency objectives of tariff setting are satisfied, because the method of calculation is based on future economic resource costs (rather than sunk costs), and also incorporates economic considerations such as shadow prices and externalities. The structuring of marginal costs permits an efficient and fair allocation of the tariff burden on consumers. In the second stage of developing a LRMC based tariff, deviations from strict LRMC are considered, to meet important financial and other social, economic (second-best) and political criteria. This second step of adjusting strict LRMC is generally as important as the first stage calculation, especially in the developing country context.

The LRMC approach provides an explicit framework for analyzing system costs and setting tariffs. If departures from the strict LRMC are required for non-economic reasons, then the economic efficiency cost of these deviations may be estimated even on a rough basis, by comparing the impact of the modified tariff relative to (benchmark) strict LRMC. Furthermore

since the cost structure may be studied in considerable detail during the LRMC calculations, this analysis helps to pinpoint weaknesses and inefficiencies in the various parts of the power system, e.g., overinvestment, unbalanced investment, or excessive losses, at the generation, transmission and distribution levels, in different geographic areas, and so on. This aspect is particularly useful in improving system expansion planning.

Finally, any LRMC based tariff is a compromise between many different objectives. Therefore, there is no "ideal" tariff. By using the LRMC approach, it is possible to revise and improve the tariff on a consistent and ongoing basis, and thereby approach the optimum price over a period of several years, without subjecting long-standing consumers to "unfair" shocks, in the form of large abrupt price changes.

Section B

Economics of Marginal Cost Pricing

The origins of marginal cost pricing theory date back as far as the pathbreaking efforts of Dupuit and subsequently Hotelling; Ruggles provides a comprehensive review of work in this area up to the 1940's. 1/ The development of the theory, especially for application in the electric power sector, received a strong impetus from the work of Boiteux, Steiner, and others, from the 1950's onwards. 2/ Recent work has led to more sophisticated investment models which permit determination of marginal costs, developments in peak load pricing, consideration of the effects of uncertainty and the costs of power shortages, and so on. 3/

1/ P. Dupuit, "De l'Utilite et de sa Mesure," La Reforma Soziale, Turin, (1932); H. Hotelling, "The General Welfare in Relation to Problems of Railway and Utility Rates," Econometrica, vol. 6 (July 1938), pp. 242-269; and N. Ruggles, "The Welfare Basis of the Marginal Cost Pricing Principle," Review of Economic Studies, vol. 17 (1949-50), pp. 29-46, and "Recent Developments in the Theory of Marginal Cost Pricing," ibid., pp. 107-126.

2/ See for example: M. Boiteux, "La Tarification des Demandes en Pointe," Revue Generale de l'Electricite, vol. 58, (1949), P. Steiner, "Peak Loads and Efficient Pricing," Quarterly Journal of Economics (November 1957); M. Boiteux and P. Stasi, "The Determination of Costs of Expansion of an Interconnected System of Production and Distribution of Electricity," in James Nelson, Ed., Marginal Cost Pricing in Practice, Prentice-Hall, Englewood Cliffs, N.J. (1964); O.E. Williamson, "Peak Load Pricing and Optimal Capacity under Indivisibility Constraints," The American Economic Review, vol. 56, No. 4 (September 1966), pp. 810-827; and R. Turvey, Optimal Pricing and Investment in Electricity Supply, Cambridge M.I.T. Press (1968).

3/ See for example: Symposium on Peak Load Pricing, in The Bell Journal of Economics, vol. 7 (Spring 1976), pp. 197-250; R. Turvey and D. Anderson, Electricity Economics, Johns Hopkins (1977), M.A. Crew and P.R. Kleindorfer, "Reliability and Public Utility Pricing," American Economic Review, vol. 68 (March 1978); R. Sherman and M. Visscher, "Second Best Pricing with Stochastic Demand," ibid.; Marginal Costing and Pricing of Electrical Energy, Proceedings of the State of the Art Conference, Canadian Electrical Association, Montreal (May 1978); and M. Munasinghe, Economics of Power System Reliability and Planning, Johns Hopkins Press, Baltimore (1979).

This section consists of a review of the basic economic principles of marginal cost pricing and a summary of the current state-of-the-art. Further details of the theory may be found in the references given earlier.

B.1 Basic Marginal Cost Theory

The rationale for setting price equal to marginal cost may be clarified with the simple supply-demand diagram shown in Figure B.1. Let $EFGD_0$ be the demand curve (which determines the kWh of electricity demanded per year, at any given average price level), while AGS is the supply curve (represented by the marginal cost MC of supplying additional units of output).

At the price p, and demand Q, the total benefit of consumption is represented by the consumers willingness-to-pay, i.e., the area under the demand curve OEFJ. The cost of supplying the output is the area under supply curve OAHJ. Therefore, the net benefit, or total benefit minus supply cost, is given by the area AEFH. Clearly, the maximum net benefit AEG is achieved when price is set equal to marginal cost at the optimum market clearing point G, i.e., (P_o, Q_o).

In mathematical terms, the net benefit is given by:

$$NB = \int_0^Q p(q).dq - \int_0^Q MC(q).dq$$

Where p(Q) and MC(Q) are the equations of the demand and supply curves respectively maximizing NB yields: $d(NB)/dQ = p(Q) - MC(Q) = 0$ which is the point of intersection of the demand and marginal cost curves (P_o, Q_o).

The analysis so far has been static, and therefore we now consider the dynamic effect of growth of demand from year 0 to year 1, which leads to an outward shift in the demand curve from D_o to D_1. Assuming that the correct

market clearing price p_o was prevailing in year 0, excess demand equal to GK will occur in year 1. Ideally, the supply should be increased to Q_1 and the new optimum market clearing price established at p_1. However, the available information concerning the demand curve D_1 may be incomplete, making it difficult to locate the point L.

Fortunately, the technical relationships underlying the production function usually permit the marginal cost curve to be determined more accurately. Therefore, as a first step, the supply may be increased to an intermediate level Q′, at the price p′. Observation of the excess demand MN indicates that both the supply and the marginal cost price should be further increased. Conversely, if we overshoot L and end up in a situation of excess supply, then it may be necessary to wait until the growth of demand catches up with the over-capacity. In this iterative manner, it is possible to move along the marginal cost curve towards the optimum market clearing point. It should be noted that, as we approach it, the optimum is also shifting with demand growth, and therefore we may never hit this moving target. However, the basic rule of setting price equal to the marginal cost and expanding supply until the market clears, is still valid. 1/

1/ This simple rule has to be modified when there are constraints in the economy; in particular, the consequences of shadow pricing of inputs, second best considerations, and subsidized social prices for poor consumers, are clarified in Appendix 2.

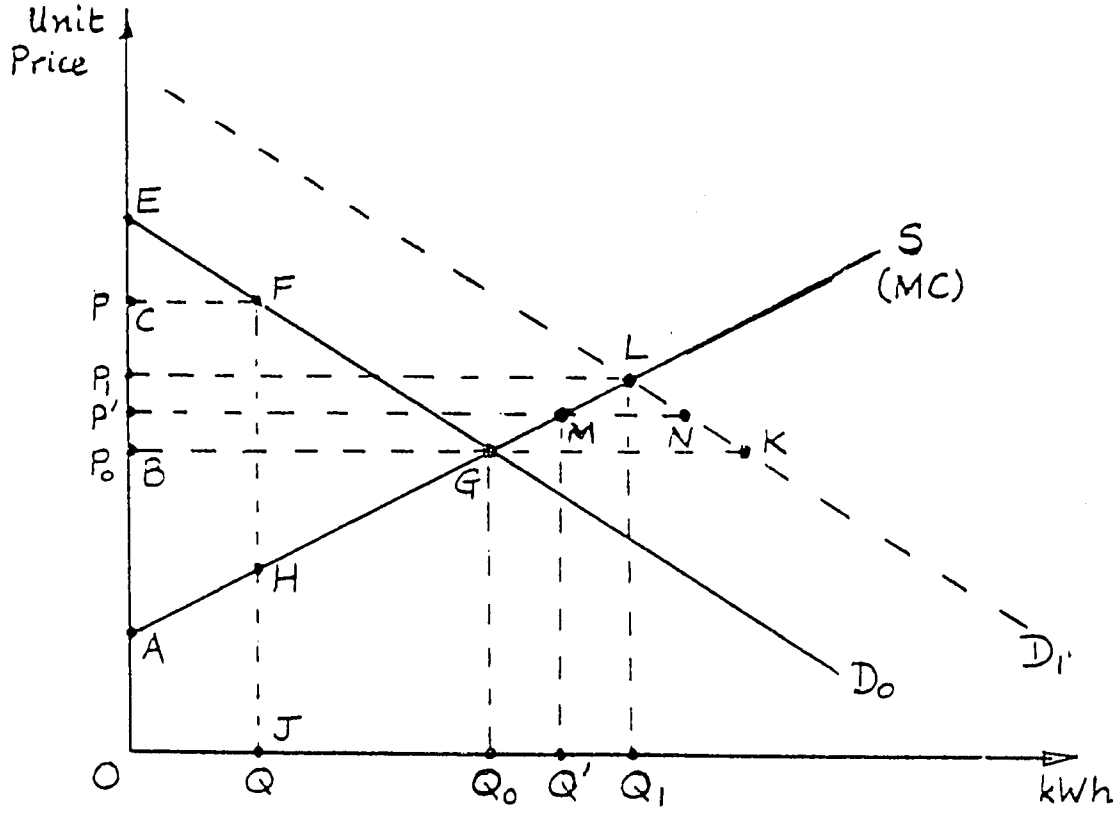

Figure B.1. Supply and Demand Diagram for Electricity Consumption

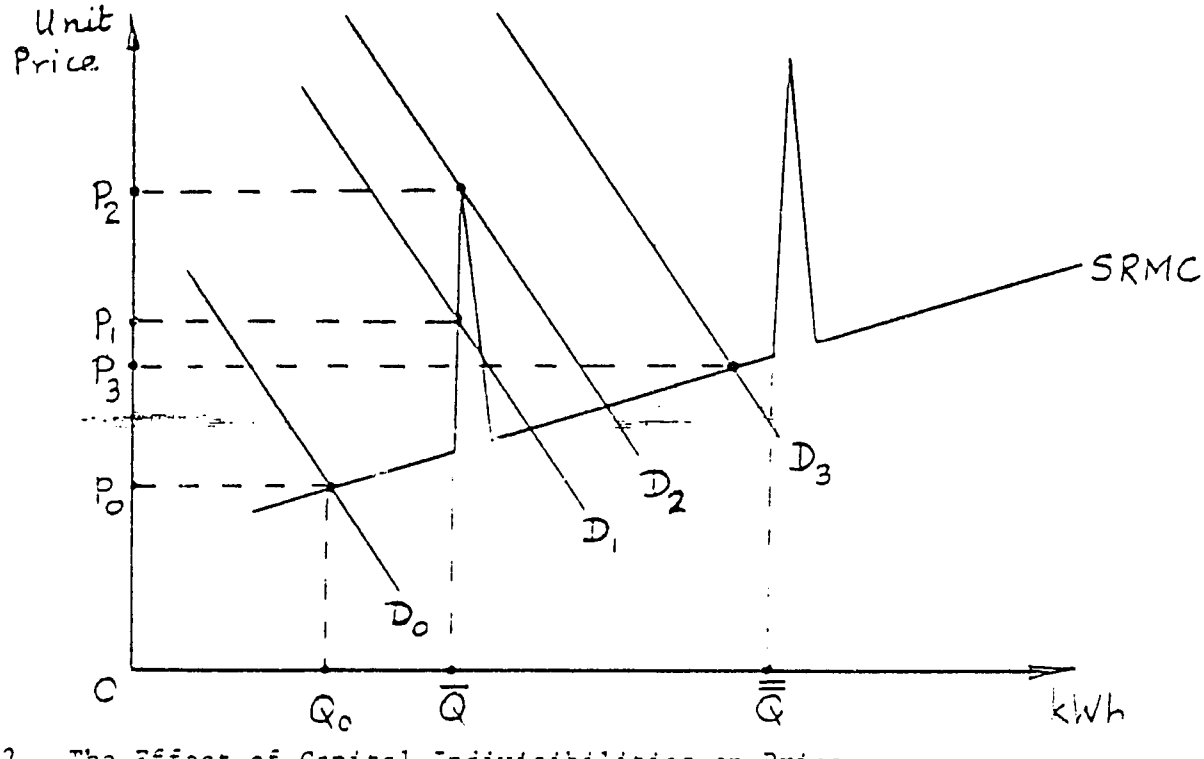

Figure 3.2. The Effect of Capital Indivisibilities on Price

B.2 Capital Indivisibilities and Peak Load Pricing

Next, the effect of capital indivisibilities or lumpiness of investments, is examined with the help of Figure B.2. This analysis recognizes the fact that, owing to economies of scale, capacity additions to power systems (especially generation) tend to be large and long-lived. Suppose that in year 0, the maximum supply capacity is $\bar{Q}$, while the optimum price and output combination (p_o, Q_o) prevails, corresponding to the demand curve D_o and the short run marginal cost curve SRMC (e.g., fuel, operating and maintenance costs). Now if capacity is to be increased from $\bar{Q}$ to $\bar{\bar{Q}}$, there will be a sharp spike in the marginal cost curve.

As demand grows from D_o to D_1 over time, the price must be increased to p_1 to clear the market. When the demand curve has shifted to D_2 and the price is p_2, plant is added on to increase the capacity to $\bar{Q}$. However, as soon as the capacity increment is completed and becomes a sunk cost, SRMC falls to its old trend line. Therefore, p_3 is the optimum price corresponding to demand D_3. Generally, the large price fluctuations during this process will be unacceptable to consumers. This practical problem may be avoided by adopting a long run marginal cost (LRMC) approach, and recognizing the need for peak load pricing, as described below.

The basic peak load pricing model shown in Figure B.3 has two demand curves; for example, D_{pk} could represent the peak demand during the x daylight and evening hours of the day when electric loads are large, while D_{op} would indicate the off-peak demand during the remaining (24-x) hours when loads are light. The marginal cost curve is simplified assuming a single type of plant with the fuel, operating and maintenance costs given by the constant a, and

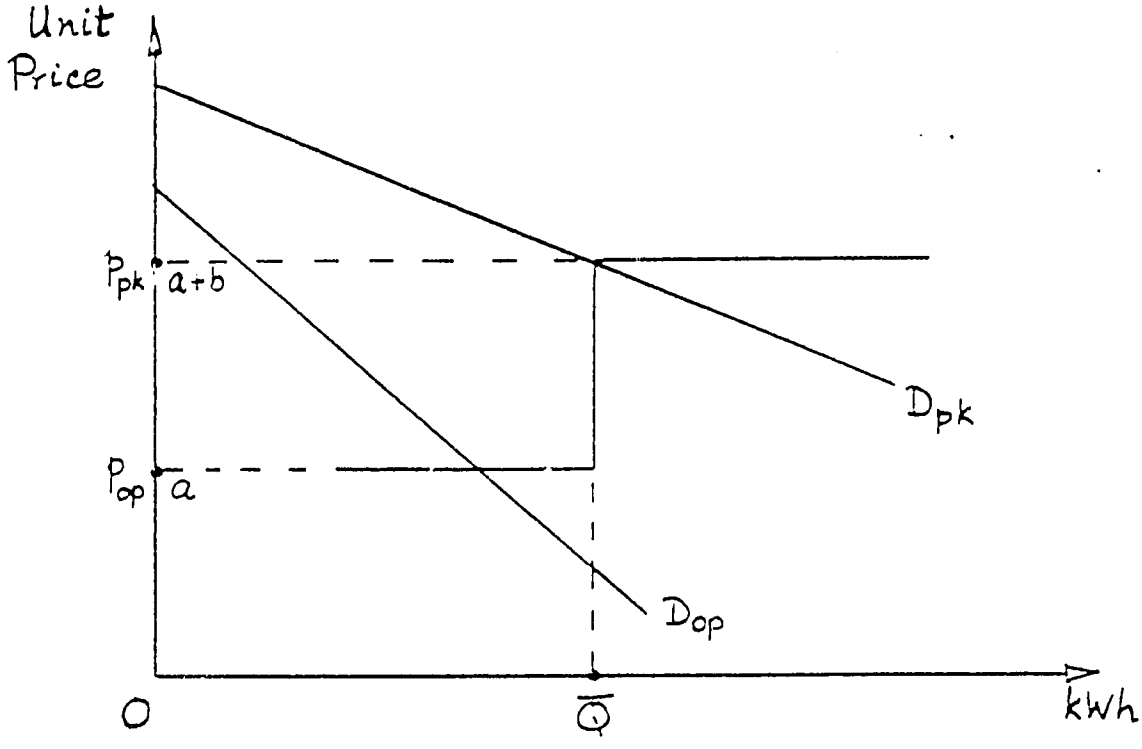

Figure B.3. Peak Load Pricing Model

the LRMC of adding to capacity (e.g., investment costs suitably annuitized and distributed over the lifetime output of the plant) given by the constant b. The static diagram has been drawn to indicate that the pressure on capacity arises due to peak demand D_{pk}, while the off-peak demand D_{op} does not infringe on the capacity $\bar{Q}$. The optimum pricing rule now has two parts corresponding to two distinct rating periods (i.e., differentiated by the time of day);

peak period price : $p_{pk} = a + b$

off-peak period price: $p_{op} = a$

The logic of this simple result is that peak period users, who are the cause of capacity additions, should bear full responsibility for the capacity costs as well as fuel, operating and maintenance costs, while off-peak consumers only pay the latter costs (see also Appendix 1).

B.3 Extensions of Simple Models

The models presented so far have been deliberately idealized and simplified to clarify the basic principles involved. Extensions of these models which incorporate and analyze the economics of real-world power systems more realistically are reviewed below.

First, the usual procedure adopted in marginal cost pricing studies may require some iteration. Typically, a long-range demand forecast is made assuming some given future evolution of prices, a least cost system expansion plan is determined to meet this demand, and LRMC is computed on the basis of latter. However, if the estimated LRMC which is to be imposed on consumers is significantly different from the original assumption regarding the evolution of prices, then the first round LRMC estimates must be fed back into the model to revise the demand forecast and repeat the LRMC calculation.

In theory, this iterative procedure could be repeated until future demand, prices, and LRMC estimates become mutually self-consistent. In practice, uncertainties in price elasticities of demand and other data may dictate a more pragmatic approach in which the LRMC results would be used to devise power tariffs after only one iteration. The behavior of demand is then observed over some time period and the LRMC re-estimated and tariffs revised to move closer to the optimum, which may itself have shifted meanwhile, as described in subsection B.1. The price feedback effects are most important in the so-called shifting peak case, when peak load pricing may shift the demand peak from one rating period to another. In general, problems arising from changes in the level of demand at any given time of day due to differential pricing during other rating periods have been recognized, and are being investigated.

Second, the interrelated issues of supply and demand uncertainty, reserve margins, and costs of shortages raise certain problems. The least cost system expansion plan to meet the demand forecast is generally determined assuming some (arbitrary) target level of system reliability (e.g., loss-of-load-probability or LOLP, reserve margin, etc.) Therefore, marginal costs depend on the target reliability level, when in fact economic theory suggests that reliability should also be treated as a variable to be optimized, and both price and capacity (or equivalently, reliability) levels should be optimized simultaneously. The optimum price is the marginal cost price as described earlier, while the optimum reliability level is achieved when the marginal cost of capacity additions (to improve the reserve margin) are equal to the expected value of economic cost savings to consumers due to electricity

supply shortages averted by those capacity increments. These considerations lead to a more generalized approach to system expansion planning as shown below. 1/

Consider a simple expression for the net benefits (NB) of electricity consumption, which is to be maximized:

$$NB(D,R) = TB(D) - SC(D,R) - OC(D,R)$$

where TB = total benefits of consumption if there were no outages; SC = supply costs (i.e., system costs); OC = outage costs (i.e., costs to consumers of supply shortages); D = demand; and R = reliability.

In the traditional approach to system planning both D and R are exogenously fixed, and therefore NB is maximized, when SC is minimized, i.e., least cost system expansion planning. However, if R is treated as a variable:

$$\frac{d(NB)}{dR} = -\frac{\partial}{\partial R}(SC+OC) + \frac{\partial}{\partial D}(TB-SC-OC).\frac{\partial D}{\partial R} = 0$$

is the necessary first order maximization condition.

Assuming $\frac{\partial D}{\partial R} = 0$, yields: $\frac{\partial(SC)}{\partial R} = -\frac{\partial(OC)}{\partial R}$

Therefore, as described earlier, reliability should be increased by adding to capacity until the above condition is satisfied. An alternative way of expressing this result is that since TB is independent of R, NB is maximized when total costs: TC = (SC + OC) are minimized. The above criterion is one which effectively subsumes the traditional system planning rule of minimizing only the system costs. 2/

1/ For details see M. Munasinghe, "A New Approach to System Planning," IEEE Transactions on Power Apparatus and Systems, vol. PAS-78, (July-August 1979).

2/ The emphasis on outage costs requires greater effort to measure these costs; see M. Munasinghe and M. Gellerson, Economic Criteria for Optimizing Power System Reliability Levels," The Bell Journal of Economics, vol. 10 (Spring 1979); and M. Munasinghe, "The Costs of Electric Power Shortages to Residential Consumers," Journal of Consumer Economics (forthcoming).

Third, some problems are raised by the dichotomy of having to choose between short and long run marginal costs, i.e., SRMC versus LRMC. The short-run (SRMC) may be defined as the cost of meeting additional electricity consumption, with capacity fixed, while the long run marginal cost (LRMC) is the cost of providing an increase in consumption (sustained indefinitely into the future) in a situation where optimal capacity adjustments are possible. When the system is optimally planned and operated (i.e., capacity and reliability are optimal), SRMC and LRMC coincide. However, if the system plan is sub-optimal, significant deviations between SRMC and LRMC will have to be resolved within the pricing policy framework. Finally, if there are substantial outage costs outside the peak period, then the optimal marginal capacity costs may be allocated among the different rating periods in proportion to the corresponding marginal costs. 1/

B.4 Shadow Pricing

In the idealized world of perfect competition the interaction of atomistic profit maximizing procedures and atomistic utility maximizing consumers gives rise to a situation that is called pareto-optimal. In this state, prices reflect the true marginal social costs, scarce resources are efficiently allocated, and for a given income distribution, no one person can be made better off without making someone else worse off. 2/

1/ It has been suggested that capacity costs should be allocated to different rating periods in inverse proportion to LOLP, but this would be unsatisfactory because aggregate reliability indices such as LOLP are poor proxies for pro-rating outage costs.

2/ See for example: E. J. Mishan, Cost Benefit Analysis, Praeger, New York (1976) part vii.

However, conditions are likely to be far from ideal in the real world. Distortions due to monopoly practices, external economies and diseconomies (which are not internalized in the private market), interventions in the market process through taxes, import duties and subsidies, etc., all result in market (or financial) prices for goods and services, which may diverge substantially from their shadow prices or true economic values. Moreover, if there are large income disparities, the passive acceptance of the existing skewed income distribution, which is implied by the reliance on strict efficiency criteria for determining economic welfare, may be socially and politically unacceptable. Such considerations necessitate the use of appropriate shadow prices (instead of market prices) of inputs to the electricity sector, to determine the optimal investment program as well as LRMC, especially in the developing countries where market distortions are more prevalent.

The basic concepts of shadow pricing are summarized below, with special reference to so called efficiency (shadow) prices which emphasize efficient resource allocation and neglect income distributional considerations. 1/

In order to derive a consistent set of shadow prices for goods and services it is necessary to adopt a common yardstick or numeraire to measure economic value. For example, a rupee's (or dollar's) worth of a certain good purchased in a duty free shop is likely to be more than the physical quantity

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1/ For details including a discussion of social shadow prices which incorporate income distributional effects, see: M. Munasinghe and J. J. Warford, "Shadow Pricing and Power Tariff Policy," in Marginal Costing and Pricing of Electrical Energy, op. cit., pp. 159-180. A more general reference is: L. Squire and H. van der Tak, Economic Analysis of Projects, Johns Hopkins Press, Baltimore (1975).

of the same good obtained for one rupee (or one dollar) in a retail store, after import duties and taxes have been levied. Therefore, it is possible to intuitively distinguish between a border priced rupee, which is used in international markets free of import tariffs, and a domestic priced rupee, which is used in the domestic market subject to various distortions. A more sophisticated example of the value differences of a currency unit in various uses arises in countries where the aggregate investment for future economic growth is considered inadequate. In such a case, a rupee of savings (which could be invested to increase the level of future consumption) may be considered more valuable in the national context than a rupee devoted to current consumption.

One numeraire that has proved to be most appropriate in many instances is a unit of uncommitted public income at border prices, which is essentially the same as freely disposable foreign exchange available to the government, but expressed in terms of units of local currency converted at the official exchange rate. 1/ Therefore, the discussion in the next section is developed in terms of this particular yardstick of value. The border priced numeraire is particularly relevant for the foreign-exchange scarce developing countries, and represents the set of opportunities available to a country to purchase goods and services on the international market. The numeraire and shadow prices are in real terms, i.e., net of inflation.

The estimation and use of shadow prices is facilitated by dividing economic resources into tradable and non-tradable items. The values of

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1/ See I.M.D. Little and J. A. Mirrless, Project Appraisal and Planning for Developing Countries, Basic Books, New York (1974), Chap. 9, and L. Squire and H. van der Tak, op. cit., chap. 3. A numeraire based on private consumption is advocated in: P. Dasgupta, A. Sen and S. Marglin, Guidelines for Project Evaluation (UNIDO), United Nations, New York (1972).

directly imported or exported goods and services are already known in terms of their border prices, i.e., their foreign exchange costs, converted at the official exchange rate. However, locally purchased items whose values are known only in terms of domestic market prices, need to be converted to border shadow prices by multiplying the former prices by appropriate conversion factors (CF). 1/ The free trade assumption is not required to justify the use of border prices since domestic price distortions are, in effect, adjusted by netting out all taxes, duties and subsidies.

The most important tradable inputs used in the electric power sector are capital goods and petroleum-based fuels; in each case world market or border prices (c.i.f. for imports and f.o.b. for exports) may be used as shadow prices where appropriate. In some countries other fuels, such as coal deposits, are available, for which there may be no clear-cut alternative (export) market. In these cases, the marginal social cost (MSC) of production e.g., resource cost of extracting the coal, may be used. The most important non-tradable primary factor inputs are labor and land, which are discussed later. The shadow prices of other non-tradable goods and services from many sectors can be determined in terms of their MSC through appropriate decomposition. For example, suppose one rupee's worth (in domestic market prices) of the output of the domestic construction sector may be broken down successively into n components (such as capital, labor, materials, etc.), which are themselves valued at rupees a_1, a_2, ..., a_n (in terms of border prices).

1/ In the subsequent discussion the pair of terms: border and shadow prices, will be used synonymously, as well as the pair: domestic and market prices.

Since the conversion factor of any good is defined as the ratio of the border price to domestic price, the construction conversion factor equals:

$$\sum_{i=1}^{n} a_i$$

In the case of non-tradables which are not important enough to merit individual attention, or lack sufficient data, the standard conversion factor (SCF) may be used. The SCF is equal to the official exchange rate (OER) divided by the more familiar shadow exchange rate (SER), appropriately defined. Conversion of domestic priced values into border price equivalents by application of the SCF to the former, is conceptually the inverse of the traditional practice of multiplying foreign currency costs by the SER (instead of the OER), to convert to the domestic price equivalent. A convenient approximation to the standard conversion factor is the ratio of the official exchange rate to the free trade exchange rate (FTER), when the country is moving toward a freer trade regime. This estimate of the SCF therefore reflects the average level of import duties and exports subsidies, and is usually less than unity.

Consider a typical case of unskilled labor in a labor surplus country, e.g., rural workers employed for dam construction. The foregone output of workers used in the electric power sector is the dominant component of the shadow wage rate (SWR). Complications arise because the original rural income earned may not reflect the marginal product of agricultural labor, and furthermore, for every new job created, more than one rural worker may give up his former employment. Allowance must also be made for seasonality of activities such as harvesting. In theory, if the laborer has to work harder in a new job than before, then the disutility of foregone leisure should be included in the SWR, but in practice this component is ignored. Overhead costs incurred,

such as transportation expenses, should also be considered. The foregoing may be summarized by the following basic equation for the efficiency shadow wage rate:

$$ESWR = a.m + c.u$$

where m and u are the foregone marginal output and overhead costs of labor in domestic prices, and a and c are corresponding conversion factors to convert these values into border prices.

In the case of land inputs, the appropriate shadow value placed on this primary factor depends on its location. In most cases, it is assumed that the market price of urban land is a good indicator of its economic value in domestic prices, and the application of an appropriate conversion factor, e.g., the SCF, to this domestic price will yield the border price cost of urban land inputs. Rural land which has an alternative use in agriculture may be valued at its opportunity cost, i.e., the net benefit of foregone agricultural output. The marginal social cost of other rural land is usually assumed to be negligible, unless there is a specific reason to the contrary, e.g., the flooding of virgin jungle because of a hydroelectric dam may involve the loss of valuable timber or spoilage of a recreational area which has commercial potential.

The shadow price of capital is usually reflected in the discount rate or accounting rate of interest (ARI), which is defined as the rate of decline in the value of the numeraire over time. In practice the opportunity cost of capital (OCC) may be used as a proxy for the ARI, in the pure efficiency price regime. The OCC is defined as the expected value of the annual stream of consumption (in border prices), net of replacement, which is yielded by the investment of one unit of public income, at the margin.

If the LRMC is calculated by shadow pricing the inputs using border prices, it is necessary to make a further adjustment to convert this shadow priced LRMC into an equivalent optimal electricity price which will be perceived and interpreted by consumers like any other domestic market price. Thus, if only economic efficiency considerations are considered, a typical expression for the optimal market price based on LRMC would be:

$$p_e^* = (MCB_e/b)$$

As explained in Appendix 2, the value of b for a given consumer group depends on the expenditure pattern of these electricity users, and therefore it is possible to have different prices p_e^* for various categories of electricity consumers, e.g., residential, industrial, etc., based on the same value of MCB_e. However, it may sometimes be simpler to use an economy wide average value of b, such as the SCF, for all electricity consumers, especially when detailed information on different consumer categories is unavailable. In such a case, since SCF < 1 usually, the optimal market price is greater than the border priced LRMC, i.e., $p_e^* > MCB_e$. 1/

1/ A simple numerical example will illustrate this point. Suppose that based on the world import price for high speed diesel fuel and the running costs of peaking gas turbines, the border priced LRMC of peak period energy is MCB_e = Pesos 1.6 per kWh, i.e., US¢8 per kWh times the official exchange rate (OER) of Pesos 20 per US$. Let the appropriate shadow exchange rate (SER) which reflects the average level of import duties and export subsidies (e.g., FTER) be Pesos 25 per US$. Therefore SCF = OER/SER = 0.8 and the optimal market price for peak period energy: p_e^* = 1.6/0.8 = Pesos 2 per kWh.

Section C

Calculating Strict LRMC

Strict LRMC may be defined broadly as the incremental cost of optimum adjustments in the system expansion plan and system operations attributable to an incremental demand increase which is sustained into the future. 1/ However, LRMC must be evaluated within a disaggregated framework. This structuring of LRMC is based chiefly on technical grounds and may include: differentiation of marginal costs by time of day, voltage level, geographic area, season of the year, and so on. The degree of structuring and sophistication of the LRMC calculation depends on data constraints and the usefulness of the results, given the practical problems of computing and applying a complex tariff; e.g., in theory, the LRMC of each individual consumer at each moment of time, may be estimated.

The calculation of strict LRMC is discussed below, with the structuring framework limited to one which is of operational value in a typical developing country. Points at which the computation may be pursued at a more sophisticated level are indicated in the text. The methodology of computing

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1/ The word increment is used to convey the concept of a small but discrete lump of costs or demand, since the term marginal is often interpreted in the strictly mathematical sense, with reference to an infinitesimal change. In the present context, both words may be used interchangeably, to denote a discrete change.

LRMC is summarized but no attempt has been made to present a complete case study, because of space limitations. 1/

C.1 Cost Categories and Rating Periods

Three broad categories of marginal costs may be identified for purposes of the LRMC calculations: capacity costs, energy costs and consumer costs. Marginal capacity costs are basically the investment costs of generation, transmission and distribution facilities associated with supplying additional kW. Marginal energy costs are the fuel and operating costs of providing additional kWh. Marginal customer costs are the incremental costs directly attributable to consumers including costs of hook-up, metering and billing. Wherever appropriate, these elements of LRMC must be structured by time of day, voltage level and so on, as mentioned earlier.

The first step in structuring is the selection of appropriate rating periods. By examining the system load duration curves, it is possible to determine periods during which demand presses on capacity, e.g., at a particular time of day, or in a given season of the year. To clarify the following presentation, we make the simplifying assumptions that the system under study does not exhibit marked seasonability of demand (or supply, where hydro generation is involved), and that these are only two rating periods by time-of-

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1/ Several recent case studies are available, involving LRMC calculations in a variety of situations including: R. Turvey and D. Anderson, Electricity Economics, op.cit.; C. J. Cicchetti, W. J. Gillen and P. Smolensky, The Marginal Cost and Pricing of Electricity, Ballinger Publishing Co., Cambridge, Mass. (1977), and M. Munasinghe, "Marginal Cost Based Tariff Calculations in Developing Countries," EWT Dept. Report, World Bank, Washington, D.C. (1979).

day, i.e., peak and off-peak. 1/ Other aspects of structuring will be introduced later during the analysis.

C.2 Marginal Capacity Costs

Consider Figure C.1 which shows the typical annual load duration curve (LDC) for the system ABEF in the starting year 0, as well as the two rating periods: peak and off-peak. As demand grows over time, the LDC increases in magnitude, and the resultant forecast of peak demand is given by the curve D in Figure C.2, starting from the initial value MW_o. The LRMC of capacity may be determined by asking the following question: what is the change in system capacity costs ΔC associated with a sustained increment ΔD in the long run peak demand (as shown by the shaded area of Figure C.1 and the broken line $D + \Delta D$ in Figure C.2). Consequently, the LRMC of generation would be $(\frac{\Delta C}{\Delta D})$, where the increment of demand ΔD is marginal both in time, and in terms of MW. 2/

1/ If the duration of the peak period is defined too narrowly, peak-load pricing is more likely to cause a shift in the peak to the off-peak period (see also sub-section B.3). For a review of the application and results of peak load pricing policies in European countries, see: B. M. Mitchell, W. G. Manning, Jr., and J. P. Acton, Peak Load Pricing, Balliner Publ. Co., Cambridge, Mass. (1978). Some very recent results of time-of-day pricing studies in the U.S. are given in: A. K. Miedama, S. B. White, C. A. Clayton and D. P. Lifson, "Analysis of Experimental Time of Use Electricity Prices," Tenth Annual Conference on Current Issues in Public Utility Regulation, Williamsburg, Va. (December 1978), Research Triangle Institute, North Carolina.

2/ In theory, ΔD can be either positive or negative, and generally the ratio $(\Delta C/\Delta D)$ will vary with the sign as well as the magnitude of ΔD. If many such values of $(\Delta C/\Delta D)$ are computed, it is possible to average them to obtain LRMC. However, the easiest procedure would be to consider only a single representative positive increment of demand.

In an optimally planned system, the change in the expansion program to meet the new incremental load would normally consist of advancing the commissioning date of future plant or inserting new units such as gas turbines or peaking hydro plant (see Figure C.2). If system planning is carried out using a computerized model, it is relatively easy to determine the change in capacity costs ΔC by simulating the expansion path and system operation, with and without the demand increment ΔD. 1/ Even if such a computer model is unavailable, it is usually possible to use simple considerations to derive marginal capacity costs. For example, suppose gas turbines are used for peaking; then the required LRMC of generating capacity ($LRMC_{Gen.\ Cap.}$) is the cost of advancing 1 kW of gas turbines, which may be estimated in terms of the cost per kW installed, annuitized over the expected lifetime. This figure must be adjusted for the reserve margin (RM%) and losses due to station use (L_{su}%). Thus, a typical expression would be:

$$LRMC_{Gen.\ Cap.} = \left\{\begin{matrix}\text{Annuitized} \\ \text{Cost per kW}\end{matrix}\right\} . (1 + RM/100) / (1 - L_{su}/100)$$

In our simple model, all capacity costs are to be charged to peak period consumers. 2/ Therefore, if the capacity costs of base load generating units are to be included in the calculations, it is very important to net out potential fuel savings due to displacement of less efficient plant by these

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1/ If a more sophisticated tariff structure having more rating periods is used, then the LRMC in any rating period may be estimated by simulating the computerized system expansion model with a sustained load increment added to the LDC during that period, i.e., just as in the case of the peak period analysis.

2/ As discussed in Section B.3, if expected outage costs are significant in a rating period outside the peak period, then it is possible to allocate marginal capacity costs over several rating periods.

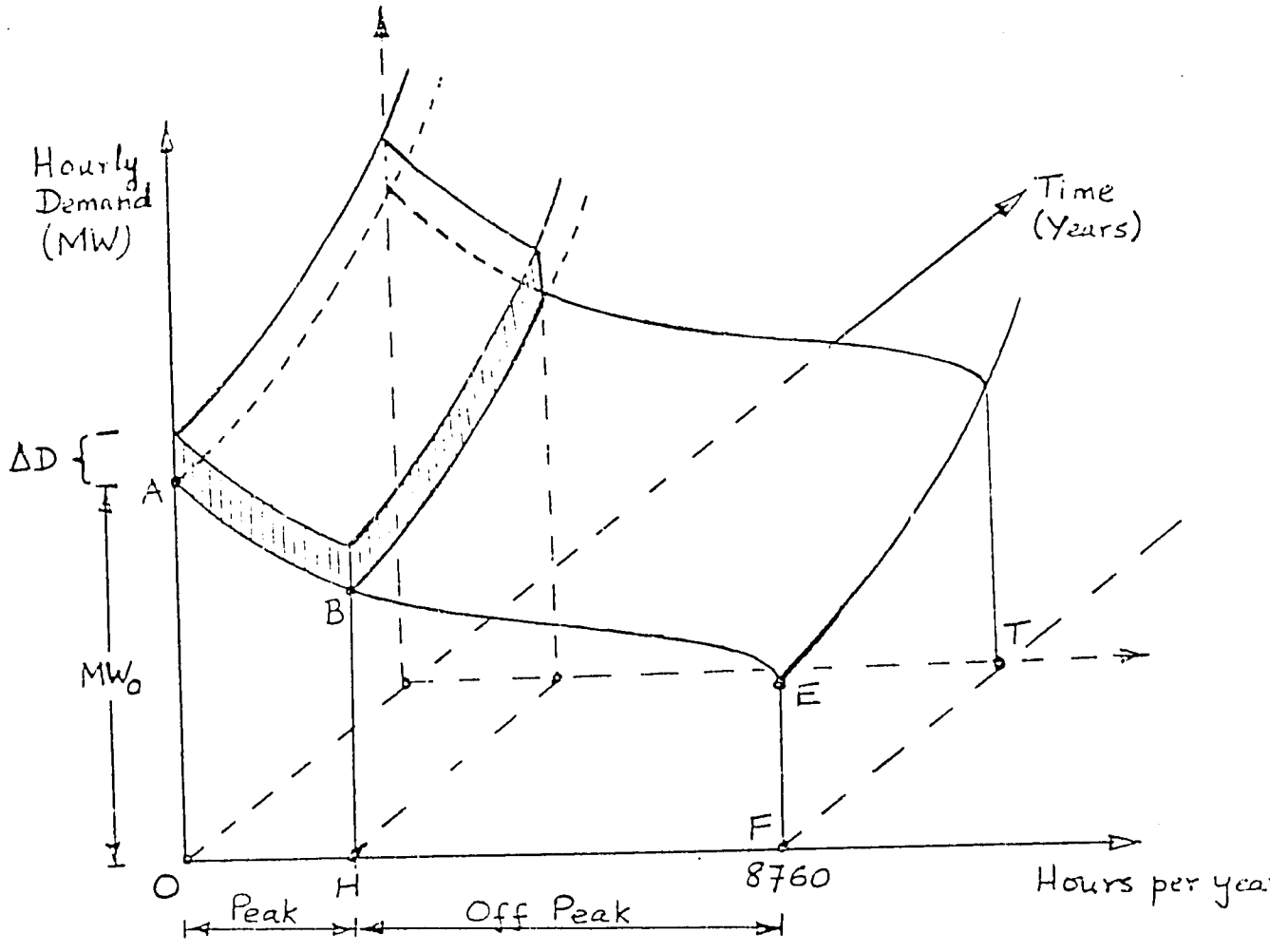

Figure C.1. Typical Annual Load Duration Curve (LDC)

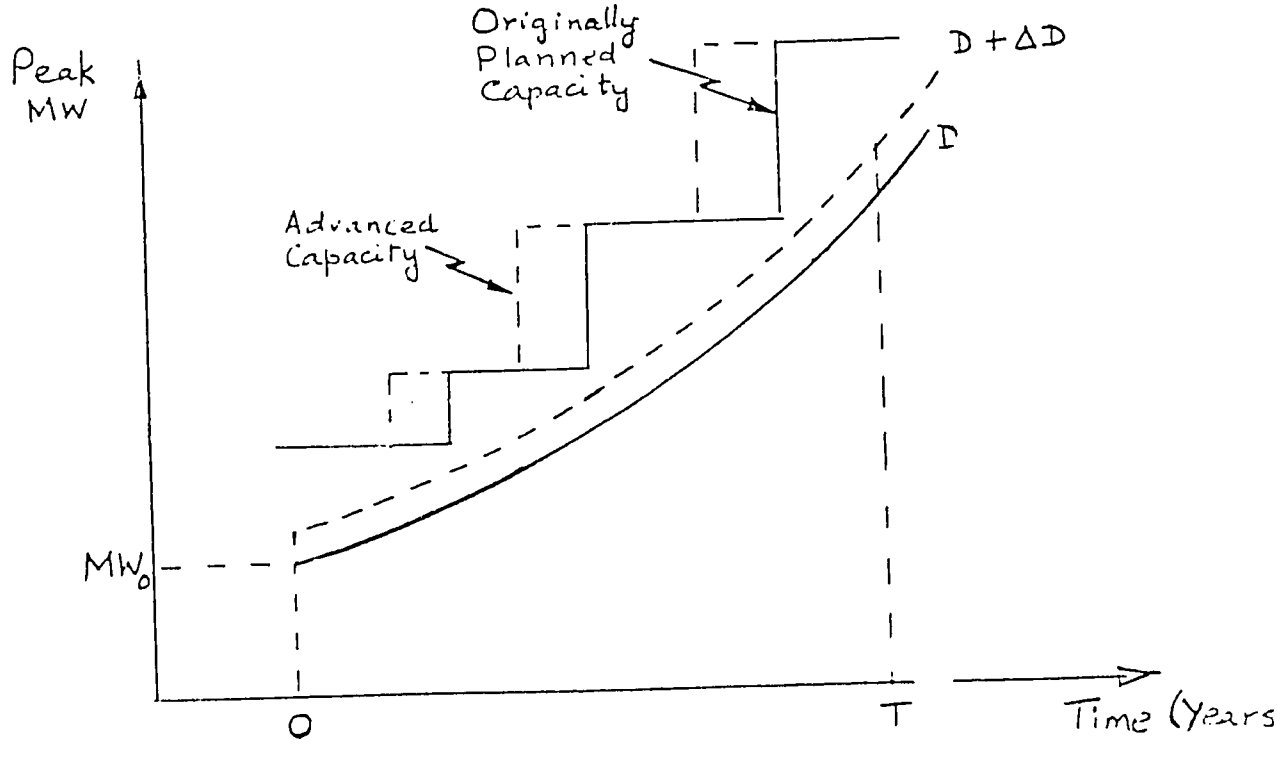

Figure C.2. Forecast of Peak Power Demand

new base load units. 1/ The rationale underlying this conclusion is clarified in Appendix 1, using a simplified system model.

Next, the LRMC of transmission and distribution (T&D) are calculated. Generally, all T&D investment costs are allocated to incremental capacity, because the designs of these facilities are determined principally by the peak kW that they carry rather than the kWh. 2/ The concept of structuring by voltage level may be introduced at this stage. Consider three supply voltage categories: high, medium and low (HV, MV, LV). Consumers at each voltage level are charged only upstream costs. Therefore, capacity costs at each supply voltage must be identified.

For example, assume that data is available on the investment costs associated with extra high voltage (EHV) and the HV transmission facilities. Next, the average incremental costs 3/ (AIC) of EHV and HV transmission could

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1/ From a practical point of view, it is clear that if peak consumers are incorrectly charged the high capacity costs of expensive base load units (e.g., nuclear), then it may encourage them to install their own captive gas turbine plant. Even intuitively, such a pricing policy would not appear to be very sensible.

2/ Particularly at the distribution level, the size of a given feeder may depend on local peak demand which may not occur within the system peak period. This complicates the problem of allocating distribution capacity costs among the various rating periods (see for example, M. Boiteux and P. Stasi, op. cit.)

3/ Suppose that in year i, ΔMW_i and I_i are the increase in demand served (relative to the previous year), and the investment cost respectively. Then, the AIC of capacity is given by:

$$AIC = \left[\sum_{i=0}^{T} I_i/(1+r)^i\right] / \left[\sum_{i=0}^{T} \Delta MW_i/(1+r)^i\right]$$

where r is the discount rate (e.g, the opportunity cost of capital) and T is the planning horizon (e.g., > 10 years). We note that in the AIC method the actual additional increments of demand are considered as they occur, rather than the hypothetical fixed demand increment ΔD used (more rigorously) in calculating generation LRMC. However, because there is no problem of plant mix with T&D investments, AIC andthe hypothetical increment method will yield similar results, while AIC is usually much easier to calculate using rapidly available planning data. For a more detailed description of AIC, see: R.J. Saunders, J.J. Warford and P.C. Mann, "Alternative Concepts of Marginal Cost Pricing for Public Utility Pricing: Problems and Applications in the Water Supply Sector", Staff Working Paper No. 259, World Bank, Washington D. C. (May 1977).

be computed, and annuitized (using the discount rate) over the lifetime of the plant (e.g., 30 years) to provide an estimate of this element of marginal costs ($\Delta LRMC_{HV}$). Then, the total LRMC of capacity during the peak period, at the HV level would be:

$$LRMC_{HV\ Cap.} = LRMC_{Gen.\ Cap.}/(1-L_{HV}/100) + \Delta LRMC_{HV}$$

where L_{HV}% is the percentage of incoming peak power that is lost in EHV and and HV network.

This procedure may be repeated at the MV and LV levels. Thus the LRMC of capacity to medium voltage consumers is given by:

$$LRMC_{MV\ Cap.} = LRMC_{HV\ Cap.}/(1-L_{MV}/100) + \Delta LRMC_{MV}$$

where $\Delta LRMC_{MV}$ is the element of incremental MV capacity costs (e.g., AIC of distribution substations and primary feeders), L_{MV}% is the percentage of incoming peak power that is lost at the MV level.

The LRMC of T&D calculated in this way is based on actual growth of future demand, and averaged over many consumers. However, some exceptions should be noted. First certain transmission li es may be specifically associated with particular generating sites (e.g., remote hydro), and therefore could be considered a generation cost rather than a transmission cost. Second, some transmission may be associated with specific loads, and therefore the costs of such facilities should be allocated accordingly. For example, suppose that a particular system has two geographically distinct load areas: a central area consisting of a group of cities, and a remote area which is predominantly rural. Then the concept of a generation power pool can be used to calculate a common generating cost for serving both areas, but different transmission costs may be determined for each area by allocating

the costs of transmission links appropriately. Third, it may be possible to identify facilities which are specific to certain consumers, and these could be allocated to consumer costs; e.g., a special sub-transmission link and substation for a large industry. This last point is also important in dividing the distribution costs between LV and consumer costs; e.g., a given customer may have a very long service drop line which should be specifically allocated to this user, rather than being included in the LV AIC calculation.

C.3 Marginal Energy Costs

With reference to Figure C.1, it may be deduced that LRMC of energy during the peak period will be the running costs of the machines to be used last in the merit order, to meet the incremental peak kWh represented by D. In our simple model, this would be the fuel and operating costs of gas turbines. These costs have to be adjusted by the appropriate peak loss factors at each voltage level, as in the case of marginal capacity costs.

Similarly, the LRMC of off-peak energy corresponding to a load increment during the off-peak period would usually be the running costs of the least efficient base load or cycling plant used during this period. 1/ We note that the loss factors for adjusting off-peak costs will be smaller than the peak period loss factors; resistive losses are a function of the square of the current, and current flows are greatest during the peak period. 2/

1/ Exceptions to this generalization would occur when the marginal plant used during a rating period was not necessarily the least efficient machine that could have been used. For example, less efficient plants which have long start-up times and are required in the next rating period, may be operated ealier in the loading order than more efficient plant. This would correspond to minimization of operating costs over several rating periods rather than on an hourly basis.

2/ See for example: C. J. Cicchetti, W. J. Gillen and P. Smolensky, op. cit.

Some complications arise particularly in the case of all-hydro and mixed hydro-thermal systems. First, a predominantly hydro system may be energy constrained, i.e., it may be short of reservoir storage rather than generating capacity. Thus all incremental capacity is needed primarily to generate more energy because the energy shortage precedes the capacity constraint. In this case, the distinction between peak and off-peak costs, and between capacity and energy costs, tends to blur. Because hydro energy consumed during any period (except when spilling) usually leads to an equivalent drawdown of the reservoirs, it may be sufficient only to levy a simple kWh chage at all times, e.g., by applying the AIC method of total incremental system costs.

Second, where hydro is involved, marginal energy costs have to be determined carefully. These costs would be close to zero, at times when water is being spilled or mandatorily run-off for other purposes (e.g., irrigation). However, in a mixed hydro-thermal system, if the hydro is used to displace more expensive thermal plant, then the running cost of the latter is the relevant marginal energy costs.

Third, if the pattern of operation is likely to change rapidly in the future (e.g., shift from gas turbines to peaking hydro as the marginal peaking plant, or vice versa), then the value of the LRMC of energy would have to be calculated as a weighted average, with the weights depending on the share of future generation by the different types of plant used.

C.4 Consumer Costs

These costs are those which can be readily allocated to customers. Fixed customer costs consist of non-recurrent expenses attributable to items

such as service drop lines, meters and labor for installation. These costs may be charged to the customer as a lump sum or distributed payments over several years.

Recurrent customer costs occur due to meter reading, billing, administrative and other expenses. These could be imposed as a flat charge, on a repeated basis, in addition to the usual kW and kWh charges. In general, the allocation of incremental (non-fuel) operation, maintenance and administrative costs among the three basic categories of costs: capacity, energy and customer, varies from system to system and requires specific analysis. However, these costs are usually small and will not greatly affect the results.

Section D

Adjusted LRMC Tariff Structure

Once strict LRMC has been calculated, the first stage of tariff setting is complete. In the second stage, the actual tariff structure which meets economic second best, social, financial, political and other constraints must be derived by modifying strict LRMC, and this topic is dealt with below. This process of adjusting LRMC will, in general, result in deviations in both the magnitude and structure of strict LRMC. Changes in tariff structure at this stage will be based mainly on socio-political factors, e.g., differentiation by type of consumer (residential, commercial, industrial and so on), or by income level (poor, middle and high income residential). Practical considerations such as the difficulties of metering and billing will also affect the final tariff structure.

The constraints which necessitate deviations in the final tariffs relative to strict LRMC fall into two categories. 1/ The first group consists of distortions which may be analyzed basically within an economic framework, i.e., second best considerations and subsidized (or lifeline) tariffs for low income consumers. In these cases, it is possible to quantify the extent of the deviation from strict LRMC by using an appropriate pricing model and explicit system of shadow prices. The second group includes all other considerations such as financial viability, socio-political constraints and problems of metering and billing where strict economic analysis is difficult to apply. These two groups of constraints may be interrelated, e.g., subsidized tariffs can simultaneously have economic welfare, financial and socio-political implications.

D.1 Second Best Considerations

Where prices elsewhere in the economy, especially in the case of substitutes and complements for electric power, 2/ do not reflect marginal costs, a "second best" departure from a strict marginal cost pricing policy for electricity services may be required. For example, the subsidies for imported generators and/or diesel fuel, which exist in many developing

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1/ We note that strict (shadow priced) LRMC also deviates from the LRMC calculated on the basis of financial costs, because shadow prices are used instead of the market prices of electricity sector inputs. This is done to correct the distortions in the economy. Therefore, the constraints which force further departures from strict LRMC (in the second stage of the tariff setting procedure) may also be considered consequently as distortions which impose their own shadow values on the calculation. See M. Munasinghe and J. J. Warford, op. cit., for details.

2/ More generally, price distortions affecting inputs into the production of electric power and outputs of other sectors which are electricity intensive (e.g., aluminium) should also be considered. The former category may be dealt with by direct shadow pricing of inputs, while the latter requires more detailed analysis (although such cases are rare).

countries, may make it advantageous for users to set up their own captive plant, even though to the economy as a whole this is not the least cost way of meeting the demand. The appropriate solution in this case might be for the government to revoke such subsidies or restrict imports of private generating plant. However, if transportation policy dictates the need to maintain subsidies for diesel fuel, or if strong pressure groups make such changes politically unfeasible, the low cost of (subsidized) private generation may require the setting of an optimal grid supplies electricity price, which is below strict LRMC. The extent of the deviation from strict LRMC is determined by the magnitude of the subsidy and degree of substitutability of the alternative energy source (see Appendix 2 for details).

A related question concerns the availability of subsidized kerosene which in many developing countries is aimed mainly at providing basic energy requirements for low income consumers at prices they can afford. 1/ In part, the subsidy may also prevent low income households especially in rural area from shifting to use of non-commercial fuels, e.g., wood, the over-use of which leads to deforestation and associated environmental consequences, or animal dung, which has a high opportunity cost as a fertilizer. If we assume the kerosene subsidy as given, then once again the price of electricity must be reduced proportionately.

1/ However, a number of unfortunate side effects may follow, including the practice of mixing kerosene with gasoline, which is typically sold at a higher price per gallon. The income distribution effects of such a policy may also be perverse. For example, in some countries the relatively wealthy have benefitted from the subsidy by converting prime movers which use other fuels, such as motor car engines, to kerosene use.

D.2 Subsidized or Lifeline Rates

In addition to the second best economic arguments (e.g., associated with subsidized kerosene), socio-political or equity arguments are often advanced in favor of "lifeline" rates for electric power, especially where the costs of electricity consumption are high in comparison to the relevant income levels. While the ability of electric power utilities to act as discriminating monopolists gives them an advantage in addressing these issues, it is clear that the appropriateness of the "lifeline" rate policy and the size of the rate blocks requires detailed analysis. Such an analysis would involve the study of a whole chain of interrelated energy and other effects, which are generally of a higher order of complexity in developing countries than in the developed-country context.

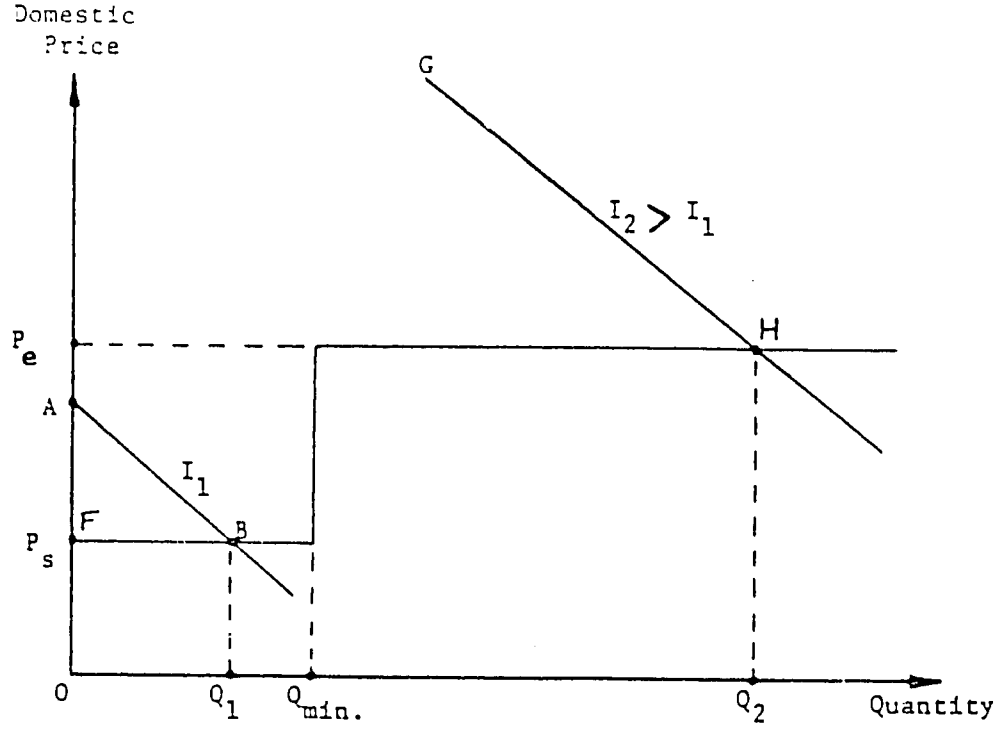

Figure D.1: ECONOMIC BASIS FOR THE SOCIAL OR LIFELINE RATE

The concept of a subsidized "social" block, or "lifeline" rate, for low income consumers has another important economic rationale, based on the income redistribution argument. We clarify this point with the aid of Figure D.1 which shows the respective demand curves AB and GH of low (I_1) and and average (I_2) income domestic users, the social tariff P_s over the minimum consumption block 0 to Q_{min}, and the marginal cost based price level P_e. All tariff levels are in domestic market prices. If the actual tariff $P = P_e$, then the average household will be consuming at the "optimal" level Q_2, but the poor household will not be able to afford the service.

If increased benefits accruing to the poor have a high social value, then, although in nominal domestic prices the point A lies below P_e, the consumer surplus portion ABF multiplied by the appropriate social weight w could be greater than the shadow price of supply. The adoption of the increasing block tariff shown in Figure D.1, consisting of the lifeline rate P_s, followed by the full tariff P_e, helps to capture the consumer surplus of the poor user, but does not affect the optimum consumption pattern of the average consumer. 1/ In practice, the magnitude Q_{min} has to be carefully determined, to avoid subsiding relatively well-off consumers; it should be based on acceptable criteria for identifying "low income" groups, and reasonable estimates of their minimum consumption levels (e.g., sufficient to supply basic requirements for lighting and minor appliances). 2/ The level of P_s relative to strict LRMC

1/ Ignoring the income effect due to reduced expenditure of the average consumer for the first block of consumption, i.e., up to Q_{min}.

2/ In most developing countries Q_{min} would be less than 100 kWh per month.

may be determined on the basis of the poor consumer's income level relative to some critical consumption level, as shown in Appendix 2. The utility's revenue constraints would also be considered in determining P_s and Q_{min}. This approach may be reinforced by an appropriate connections policy (e.g., subsidized house connections, etc.).

D.3 Financial Viability

The financial constraints most often encountered relate to the revenue requirements of the sector, and are often embodied in criteria such as some target financial rate of return on assets, or an acceptable rate of contribution towards the future investment program. In principle, for state-owned power utilities, the most efficient solution would be to set price equal to marginal cost and rely on government subsidies (or taxes) to meet the utilities financial needs. In practice, some measure of financial autonomy and self-sufficiency is an important goal for the sector. Because of the premium that is placed on public funds, a marginal cost pricing policy which results in failure to achieve minimum financial targets for continued operation of the power sector, would rarely be acceptable. The converse and more typical case, where marginal cost pricing would result in financial surpluses well in excess of traditional revenue targets, most often leads to a situation which is politically embarrassing. Therefore in either case, changes in revenues have to be achieved by adjusting the strict marginal cost tariffs.

It is intuitively clear that discriminating between the various consumer categories so that the greatest divergence from the marginal cost price occurs for the consumer group with the lowest price elasticity of demand, and

vice versa, will result in the smallest deviations from the "optimal" levels of consumption consistent with the strict marginal cost pricing rule. 1/ Generally, in developing countries the necessary data for the analysis of demand by consumer categories is rarely available, so rule-of-thumb methods of determining the appropriate tariff structure have to be adopted. However, the fiscal implications of an increasing cost industry (i.e., marginal costs greater than average costs) should be exploited to the full. Thus electric power tariffs (especially in a developing country) constitute an excellent means of raising public revenues in a manner which is generally consistent with the economic efficiency objective, at least for the bulk of the consumers who are not subsidized, while at the same time helping to supply basic energy needs to low income groups.

D.4 Other Considerations

There are several additional economic, political and social considerations that may be adequate justification for departing from a strictly marginal cost-based tariff policy. The decision to electrify a remote rural area, which may also entail subsidized tariffs because the beneficiaries are not able to pay the full price based on high unit costs, could be made on completely non-economic grounds, e.g, for general socio-political reasons such as maintaining a viable regional industrial or aricultural base, stemming rural to urban migration, or alleviating local political discontent. However, the full economic benefits of such a course of action may be much

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1/ See W. J. Baumol and D. F. Bradford, "Optimal Departures from Marginal Cost Pricing," Am. Econ. Rev., June 1970, pp. 265-283; and M. S. Feldstein, "Distributional Equity and the Optimal Structure of Public Prices," Am. Econ. Rev., 1973, pp. 32-36.

greater than the apparent efficiency costs which arise from any divergence between actual price and marginal cost. Again, this possibility is likely to be much more significant in a developing country than in a developed one, not only because of the high cost of power relative to incomes in the former, but also because the available administrative or fiscal machinery to redistribute incomes or achieve regional or industrial development objectives by other means is frequently ineffective.

For the same reason, it is particularly difficult to reform pricing policy where low incomes and a tradition of subsidized power combine to create extreme difficulties in raising prices to anywhere near marginal costs. In practice, price changes have to be gradual, in view of the costs which may be imposed on those who have already incurred expenditures on electrical equipment and made other decisions, while expecting little or no changes in traditional power pricing policies. The efficiency costs of "gradualism" can be seen as an implicit shadow value placed upon the social benefits that result from this policy.

D.5 Metering and Billing

Owing to the practical difficulties of metering and billing, the tariff structure may have to be simplified. For example, the number of customer categories, rating periods, consumption blocks, voltage levels, and so on, will have to be limited.

The degree of sophistication of metering (e.g., by time of day) depends on the net benefit of metering, problems of installation and maintenance, and so on. Thus, for very poor consumers receiving a subsidized rate, a simple current limiting device may suffice, because the cost of even simple kWh metering may exceed the net benefit equal to the lower supply cost of

reduced consumption, less the decrease in consumption benefits. In general, various forms of peak load pricing (i.e., maximum demand or time-of-day metering) would be more applicable to large MV and HV industrial and commercial consumers. 1/

Most LV consumption, especially for households, is metered only on a kWh basis, with the price per kWh based on a combined energy and "rolled in" capacity charge (e.g., using appropriate coincidence and load factors). More sophisticated meters, such as time-of-day meters which incorporate synchronous clocks, may be affected by power outages. At the other end of the scale, current limiting devices are easier to tamper with. Some developing countries may lack technically skilled labor for installation and maintenance of sophisticated meters, or even reliable meter readers. Therefore, choice of appropriate metering is usually very country specific, and is likely to involve many practical considerations.

1/ For details of metering, see: Electric Utility Rate Design Study, Rate Design and Load Control, NARUC study, Palo Alto, California (November 1977), pp. 67-77.

Appendix 1

Allocation of Capacity and Energy Costs Among Peak and Off-Peak Users

The simplified model of a typical electric power generation system is used below to show from a conceptual viewpoint, how a long run marginal cost (LRMC) analysis based on the optimal system expansion plan yields the following idealized conclusions. 1/

1. Peak users should pay off-peak LRMC of capacity as well as energy costs.
2. Off-peak users should pay only off-peak LRMC of energy.
3. LRMC of peak capacity = LRMC of base load capacity
   - net fuel savings due to this base load plant.

1/ A more realistic system model would have to consider a number of complicating factors such as a larger number of rating periods and plant types, non-coincidence of the rating periods with the economic crossover points between different plant types, economies of scale and variable heat rates for a given plant type, hydroelectric plant including pumped storage, reserve margins and stochasticity of supply and demand, and so on. The most important difference with respect to the general case is that some capacity costs would have to be borne by consumers outside the peak period. However, the bulk of the capacity costs would still be allocated to peak period users. A simplified exposition of this result is provided in: J. T. Wenders, "Peak Load Pricing in the Electric Utility Industry," The Bell Journal of Economics, Vol. 7, (Spring 1976), pp. 232-41.

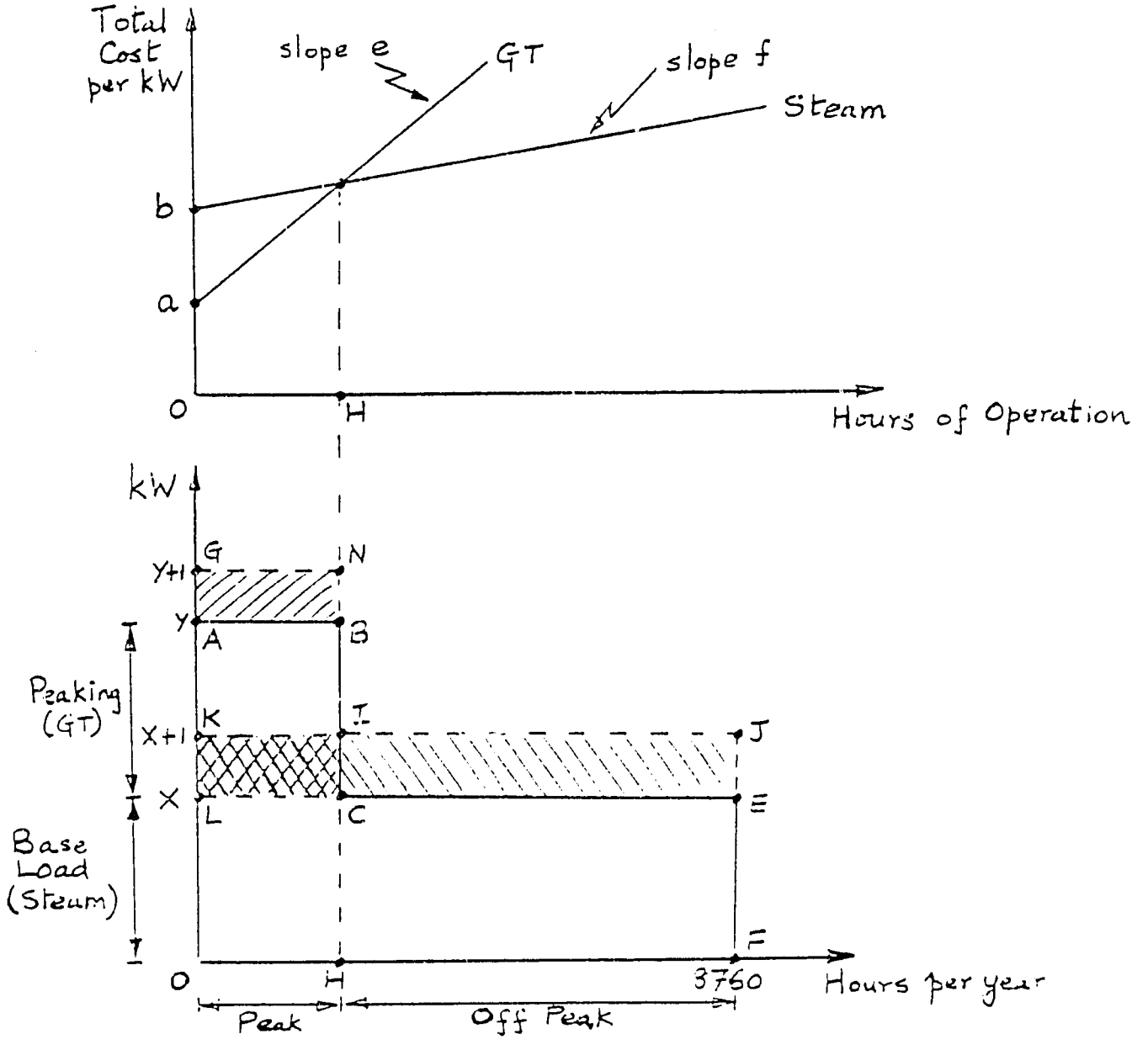

Figure 1.1. Plant Costs and Annual Load Duration Curve (LDC)

Consider an all thermal generation system having the annual load duration curve (LDC) shown in Figure 1.1. There are only two types of plant whose linearized cost characteristics are given in the table below, and also in the figure. We ignore for the moment, all losses, reserve margin, etc.

Plant Type	Capacity cost per kW installed (annuitized)	Operating Costs per hour
1. Peaking (e.g. Gas Turbines: GT)	a	e
2. Base Load (e.g. steam)	b	f

Total cost of 1 kW which is used h hours per year:

GT : a + e.h
Base: b + f.h

Let H be the hours of operation which corresponds to the crossover point for which GT and Base Load plant total costs are equal.

Therefore, a + e.H = b + f.H

$$H = \left(\frac{b-a}{e-f}\right) \quad \ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots\ldots$$

The most economic use of plant can be determined by examining the LDC, OABCEF:

(1) For planned base load operation (i.e. more than H hours per year), use base load plant; X kW

(2) For planned peak operation (i.e. less than H hours per year), use GT; (Y-X) kW

Total annual costs of meeting the demand depicted by the LDC is:-

$$C_o = X\ (b+f.T) + (Y-X)\quad (a+e.H)$$

Case 1: Only peak period demand increases by 1 kW (as shown by shaded area AGNB in Figure 1.1):

The optimal system planning response is to increase GT by 1 kW.

Total annual cost is $C_1 = X\ (b+f.T) + (Y+1-X)\ (a+e.H)$

Therefore, increase in cost: $C_1-C_o = a + e.H$

This is the increase in system costs incurred because of the 1 kW increase in marginal (or incremental) demand during the peak period, and thus the peak period user must pay this cost.

The peak costs consist of:

(1) Capacity charge = a per kW per year

(2) Energy charge = e per kWh.

It may be seen that peak users payment = a+e.H = increase in system costs.

Case 2: Only off-peak period demand increases by 1 kW (as shown by shaded area CIJE in Figure 1.1).

The optimal system planning response is to add 1 kW more of base load plant. But now there is 1 kW less of GT required than before.

Total annual cost: $C_2 = (X+1).(b+f.T) + [Y-(X+1)]\ (a+e.H)$

Therefore, increase in cost: $C_2-C_o = (b+f.T) - (a+e.H)$

$= (b-a) + (f-e).H + f\ (T-H).$

Sustituting for H from equation on (1.1)

$C_2-C_o = (b-a) + (f-e).(b-a)/(e-f) + f.(T-H)$

$C_2-C_o = f(T-H)$

Therefore, the increase in system cost incurred due to the 1 kW increase in marginal off-peak demand is equal to the energy cost of operating the base load plant during this period, and thus off-peak users must pay only this energy charge f per kWh. There are no capacity costs incurred by off peak users, since off peak users payment = f(T-H) = increase in system cost.

In particular, we note that the base load capacity cost (b) is exactly offset by the total cost saving due to GT which is not required any more (i.e., capacity cost 'a' plus net fuel cost saving (e-f).H inside the shaded area LKIC). In other words: Peak capacity cost = Base load capacity costs - net fuel savings: a = b - (e-f).H

Case 3: Both peak and off-peak demand increases by 1 kW. This case is a linear combination of Cases 1 and 2, and therefore consumer charges are:

(1) Peak capacity charge: a per kW per year;

(2) Peak energy charge: e per kWh;

(3) Off-peak energy charge: f per kWh.

Clearly, total peak and off-peak users payment = b+f.T = increase in system cost. These results may be generalized to include more types of generating units, and rating time periods; e.g., n plant types and n rating periods, where these rating periods are chosen to coincide with the economic crossover points between competing types of plant.

In this case LRMC prices would be:

0 to H_1	= peak period	:	capacity charge a_1 per kW per year, and energy charge e_1 per kWh
H_1 to H_2	= 2nd period	:	only energy charge e_2 per kWh
H_{n-1} to T	= n^{th} period	:	only energy charge e_n per kWh

Appendix 2

Model for Optimal Electricity Pricing in a Distorted Economy

In this appendix, a general expression for the socially optimal electricity price is developed based on the border prices, to compensate for distortions in the economy. From the general equation, results for optimal electricity pricing are derived, for cases which reflect:

(a) a perfectly competitive economy (classified results);

(b) economic second best considerations; and

(c) subsidized social prices or lifeline rates for poor consumers.

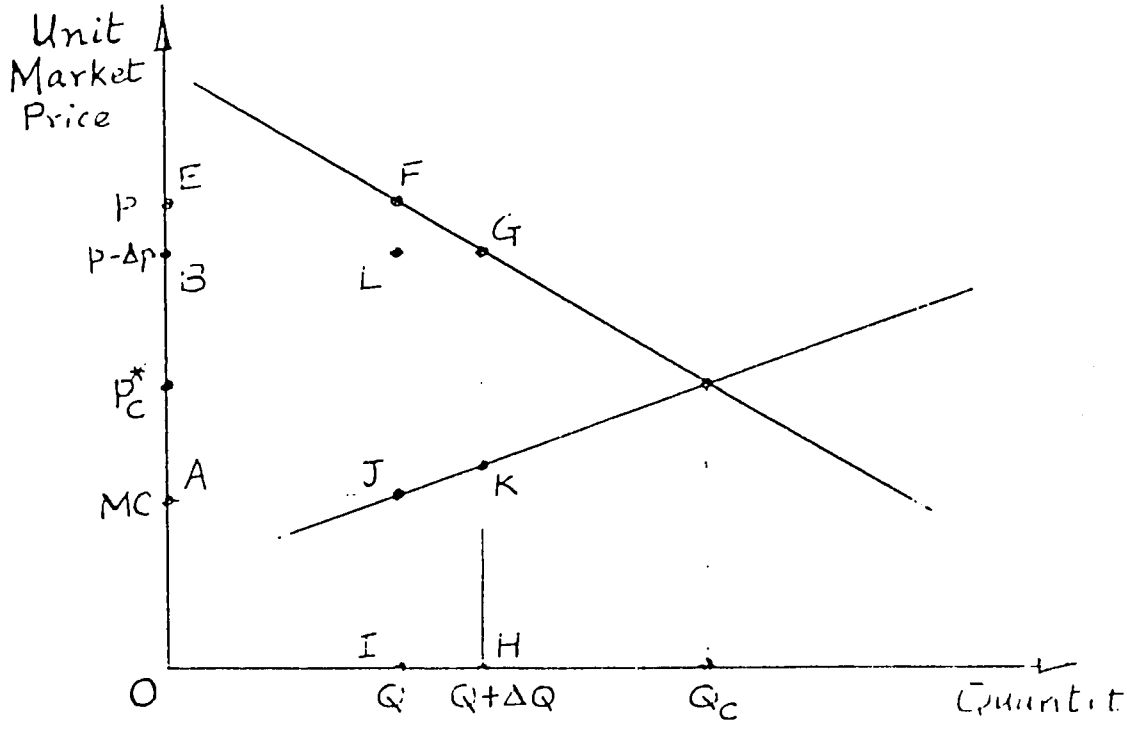

Figure 2.1 SUPPLY AND DEMAND FOR A GOOD

The supply and demand for electricity is shown in Figure 2.1, where S is the supply curve represented by the marginal cost of supply (evaluated at domestic market prices of inputs), and D is the corresponding demand curve for a specific consumer. Starting with the initial combination of price and consumption (p, Q), consider the impact of a small price reduction (dp), and the resultant increase in demand (dQ), on the net social benefits of electricity consumption.

Before evaluating the net social benefit of this price change, let us define several parameters. First, suppose we calculate the marginal cost of electricity supply MC without shadow pricing the inputs, i.e., in market prices. Then a_p is defned as the electricity conversion factor (ECF) which transforms the (market priced) marginal cost of electricity supply MC into the corresponding real economic resource cost, i.e., when all the inputs to the electricity sector are correctly shadow priced, the (border priced) marginal supply cost is $MCB_e = (a_p.MC)$. Second, we assign a specific social weight W_c to each marginal unit of consumption (valued in market prices) of a given individual i in the economy, e.g., if this electricity user is poor, the corresponding social weight may be much larger than for a rich customer, to reflect society's emphasis on the increased consumption of low income groups. Third, if the given individual's consumption of goods and services <u>other</u> than electricity (valued in market prices), increases by one unit, then the border priced marginal social cost of economic resources used (or the shadow cost to the economy) is b_i.

As a result of the price reduction, the consumer is using dQ units more of electricity, which has a market value of (p. dQ) (i.e., area IFGH). 1/ However, the consumer's income has increased by the amount PQ - (P- P) (Q + dQ), and assuming none of it is saved, this individual's consumption of other goods and services will increase by the amount (Q. dp-p. dQ), also valued in market prices (i.e., area BEFG minus area IFGH). Therefore, the consumer's total consumption, i.e., electricity plus other goods, will increase by the net amount (Q. dp) in market prices. This is the traditional increase in consumer surplus benefits. The shadow value of this increased consumption is W_c . (Q. dp) where W_c is the social weight appropriate to this consumer's income/consumption level.

Next consider the resource costs of these changes in consumption. The shadow cost of increasing electricity supply is (a_p.MC. dQ), (i.e., a_p times area IJKH), and the resources used up to provide the other additional goods consumed b_c.(Q. dp - p. dQ), where a_p is the conversion factor for electricity production, and b_c is the conversion factor for other goods consumed by this consumer. Finally, the income change of the electricity producer must also be considered, but this effect may be ignored if we assume quite plausibly that the producer is the government.

The total increase in net social benefits due to the electricity price decrease is given by:

$$NB = W_c(p.\ dQ) - a_p.(MC.\ dQ) + (W_c - b_c).(Q.\ dp - p.dQ)$$

1/ The little triangle LFG may be neglected throughout this analysis because its area is (dp. dQ)/2, where both dp and dQ are small increments.

Therefore:

$$(dNB/ dp) = Q [(W_c - b_c) + n.b_c] - n.a._p.(MC/p)$$

where n = (p. dQ/Q. dp) is the elasticity of demand (magnitude).

The necessary first order condition for maximizing net social benefits, in the limit, is d(NB)/dp=0. This yields the optimal price level:

$$p^* = a_p . MC/[b_c + (W_c - b_c)/n] \qquad (2.1)$$

This expression may be reduced to a more familiar form, by making some simplifying assumptions.

Case 1: Perfectly competitive economy where market prices and shadow prices are the same, and income transfer effects are ignored, i.e., no social weighting.

Therefore, $a_p = W_c = b_c = 1$, and equation (2.1) reduces to:

$$p_c^* = MC \qquad (2.2)$$

This is the classical result (discussed in subsection B.1), where net social benefits are maximized when price is set equal to marginal cost at the market clearing point (p_c, Q_c) in Figure 2.1.

Case 2: Income transfer effects ignored, because the marginal social benefit of consumption is equal to the marginal social cost to the economy of providing this consumption.

Therefore, $W_c = b_c$, and equation (2.1) becomes:

$$p_e^* = (a_p.MC) / b_c = MCB_e/b_c \qquad (2.3)$$

This is the optimal marginal cost based electricity price, when efficiency (shadow) prices are used which emphasize the efficient allocation of resources and neglect income distributional considerations.

As mentioned earlier, the marginal social cost of electricity supply (MCB_e) may be evaluated in a straightforward manner by applying the

appropriate shadow prices to the least cost mix of technically determined inputs used in producing electricity. However, the conversion factor b_c depends crucially on the type of consumer involved.

For residential electricity consumers, b_c represents the consumption conversion factor (CCF), which reflects the resource cost or shadow value of one (market priced) unit of the household's marginal consumption basket. If the CCF<1, then $p_e^* > (MCB_e)$.

Another interesting case illustrates the application of equation (2.3) to correct for economic second-best consideration arising from energy substitution possibilities. As an extreme case, suppose all expenditures diverted from grid supplied electricity will be used to purchase alternative energy which is subsidized by the government (e.g., kerosene for lighting, or diesel for autogeneration). In this case, b_c is the ratio of the border priced marginal cost of alternative energy to its market price; and may be written:

$$b_c = \frac{MCB_{ae}}{P_{ae}}$$

Thus from equation (2.3): 1/

$$p_e^* = MCB_e \cdot (P_{ae}/MCB_{ae}) \qquad (2.4)$$

1/ The logic of this expression may be clarified by considering the case when the actual $p_e > p_e^*$. Then the shadow cost of one unit of expenditure on electricity is MCB_e/p_e, while if this sum was used to purchase alternative energy the shadow cost would be MCB_{ae}/p_{ae}. Since $p_e > p_e^*$, $MCB_e/p_e > MCB_{ae}/p_{ae}$, and the country is better off if more electricity is used instead of the alternative energy. Therefore, p_e should be reduced to p_e^*. Similar reasoning can be used to show that if $p_e < p_e^*$, then p_e should be increased to the value p_e^*.

Since the alternative energy is priced below its border marginal cost, i.e., $b_c > 1$, then $p_e^* < MCB_e$ also. Therefore, the subsidization of substitute energy prices will result in an optimal electricity price which is below its shadow supply cost.

If it is not possible to determine the consumption patterns of specific consumer groups, then b_c could be defined very broadly as the average conversion factor for all electricity users, e.g., the SCF, as discussed in subsection 3.4.

Case 3: General

Equation (2.1) is the optimal electricity price when social (shadow) prices are used, which incorporate income distributional concerns.

Consider the case of a group of very poor consumers for whom we may assume: $W_c >> b_c(n-1)$. Therefore, equation (2.1) may be written:

$$p_s^* \approx n.MCB_e/W_c$$

An even greater simplification is possible if it is assumed that $n = 1$; thus

$$p_s^* = MCB_e/W_c$$

For illustration, suppose that the income/consumption level of these poor consumers (c) is 1/3 the critical income/consumption level ($\bar{c}$) which is like a poverty line. Then a simple expression for the social weight is:

$$W_c = \frac{\bar{c}}{c} = 3$$

Therefore $p_s^* = MCB_e/3$, which is the "lifeline" rate or subsidized tariff appropriate to this group of low income consumers.

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CASE STUDY I

ELECTRICITY TARIFFS IN INDONESIA

Sector Background

The electricity sector in Indonesia comprises PLN - the government-owned enterprise statutorily responsible for all generation, transmission and distribution of electricity in the country - captive 1/ plant installations and some municipal franchises.

It is estimated that the aggregate capacity of captive plant now equals that of PLN.

The total generating capacity available to PLN 2/ at the end of FY78 was about 2,000 MW, 40% of which was in the form of gas turbines, 23% diesel, 22% hydro and 15% steam. In Java, gas turbines now account for 50% of the total of 1,255 MW. This development of generating capacity was due to a crash program of gas turbine installations in the early seventies when PLN suffered major breakdowns in generating capacity and gas turbines were seen as the only means of adding new generating capacity quickly. It is being corrected now with the commissioning in 1979 of new steam generating capacity at Perak and Gresik (East Java), Semarang (Central Java) and Muara-Karang (West Java). These new steam stations will add 1,200 MW of base load capacity by 1982. At that time, the PLN system in Java will have 53% of steam, 20% of hydro and 27% of gas turbine plant; all PLN's uneconomic small diesel plant would be retired. The proportion of steam, hydro, gas turbines and diesel in the entire country would be 41%, 18%, 20% and 21% respectively.

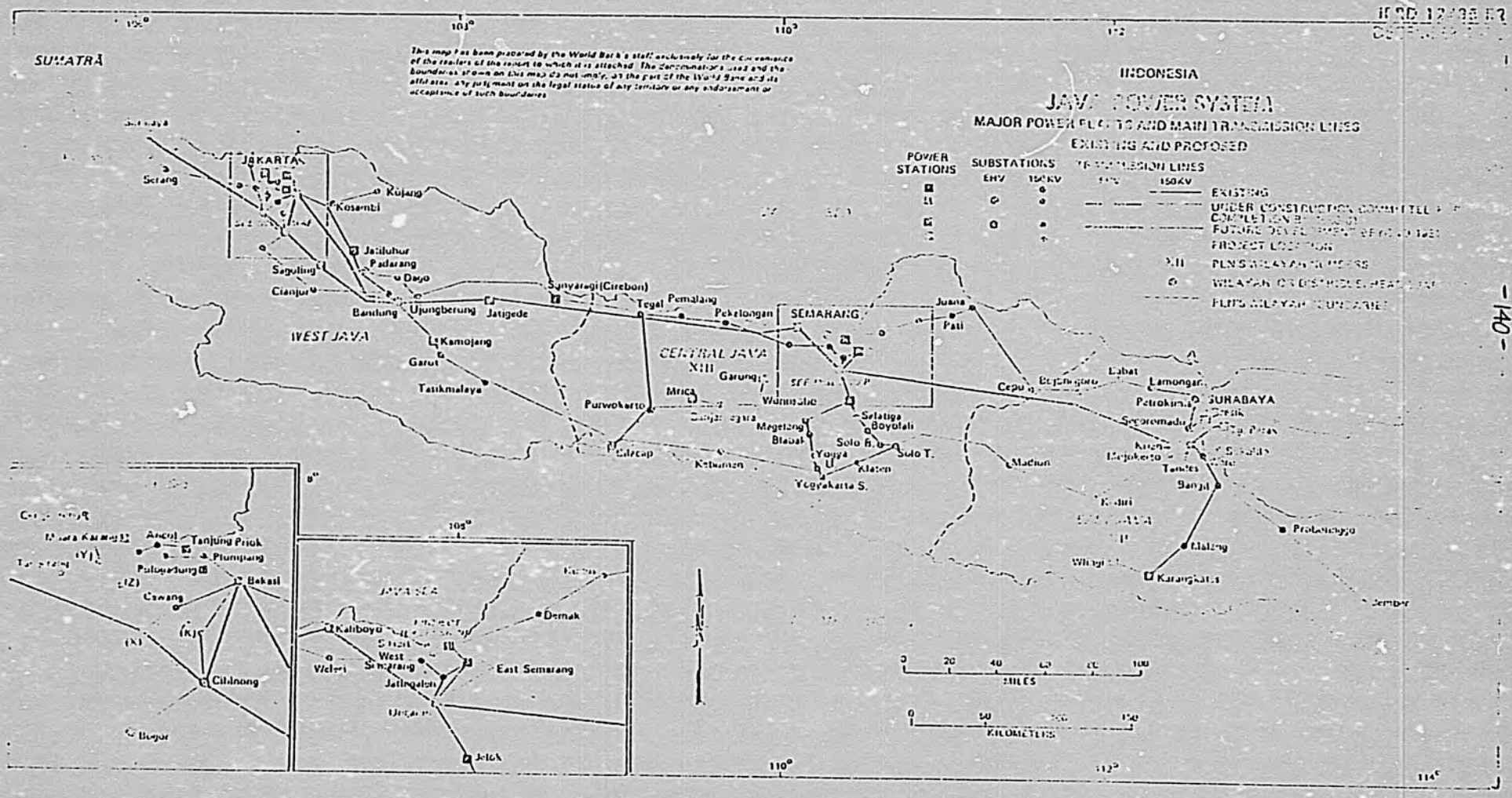
PLN operates about 3800 km of transmission lines, mostly in Java. About 2000 km of high voltage (70/150 kV) transmission lines are currently under construction and these will be completed during 1979-82. The attached Figure 6.1 shows the existing 150 kV system and extensions in progress in Java. The presently isolated systems of West, Central and East Java will be interconnected in 1980 to form an all Java grid. In addition to its main transmission lines, PLN now has in operation distribution systems aggregating some 40,000 km.

PLN's capacity expansion plans, particularly in Java, are based on tight reserve margins. The existing diesel captive installations with any economic life left will therefore continue to be utilized by their owners as emergency standby or for use during peak periods when there are restrictions on supply. Captive power installations in Java, with a few exceptions, are too small to be interconnected with the PLN system; their utilitzation will therefore continue to be poor. To a limited extent they can be taken over by PLN where the equipment is in satisfactory condition, for use in isolated areas where public supply has to be introduced. The age of these installations and difficulties in obtaining spares would however be deterring factors. PLN agrees that such equipment as can be advantageously used should not be left redundant when the sector needs it.

1/ Installed by private parties for electricity production for their onw use.

2/ Includes the 125 MW hydroelectric station owned by the Jatiluhur Authority.

Figure 6.1


INDONESIA
JAVA POWER SYSTEM
MAJOR POWER PLANTS AND MAIN TRANSMISSION LINES
EXISTING AND PROPOSED
POWER STATIONS
SUBSTATIONS
EHV
150KV
TRANSMISSION LINES
150KV
EXISTING
FUTURE
PROJECT LOCATION
SUMATRA
JAKARTA
WEST JAVA
CENTRAL JAVA
SEMARANG
SURABAYA
Serang
Kosambi
Kojang
Jatiluhur
Padarang
Dayo
Saguling
Cianjur
Bandung
Ujungberung
Jatigede
Kamojang
Garut
Tasikmalaya
Sunyaragi (Cirebon)
Tegal
Pemalang
Pekalongan
Juana
Pati
Purwokerto
Cilacap
Kebumen
Mrica
Garung
Wonosobo
Magelang
Blabak
Yogya
Yogyakarta S.
Solo B.
Solo T.
Klaten
Selatiga
Boyolali
Cepu
Bojonegoro
Lamongan
Madiun
Kediri
Malang
Karangkates
Probolinggo
Jember
Tanjung Priok
Plumpang
Pulogadung
Bekasi
Cawang
Cibinong
Bogor
Kaliboyo
Demak
West Semarang
East Semarang
Jatingaleh
Jepara
Welori
Jelok
MILES
KILOMETERS

PLN agrees that such equipment as can be advantageously used should not be left redundant when the sector needs it. PLN's connection policy for consumers with existing captive plants is to consider cases on their merits, as the situation is not amenable to generalization.

Indonesia's population has low access to electricity when compared to other countries. About 6% of the households were connected at end FY77 compared to 27% in Thailand and 32% in the Philippines. Regional imbalances exist as shown by the degrees of electrification in the regions given below.

DOMESTIC CONNECTIONS

Region	Domestic connections %
Sumatra	4.3
Kalimantan	5.0
Sulawesi	4.2
Amban	3.2
West Irian	4.6
Bali and Other Islands	2.1
Java a/	9.6
Indonesia	5.9

Rural electrification (RE) has been undertaken in a small way from funds provided to PLN by the government. An RE division was formed in 1976 in PLN to promote RE projects and the division has several projects in view.

6.2 Demand Forecast and System Characteristics

Several attempts have been made in recent years to prepare a usable demand forecast for Indonesia. This has been difficult because of low consumption levels and the background of public power supply which did not cover the total market. Furthermore, the restrictions on PLN's ability to provide supply, made PLN's past record of sales an unreliable base for future projections. In 1973, a consultant, Chas. T. Main of the USA applied an indirect method of using growth probabilities in selected sensitive economic sectors and their probable impact on other sectors. A more direct detailed assessment of the underlying demand 1/ in Java was made during 1974-76 by PCR of the UK. This study quantified the effects of restrictions on supply during peak hours, low voltage, self-generation and PLN's waiting lists. There have been no similar comprehensive demand surveys for the other islands.

Assuming that PLN's sales would not immediately rise to the levels of the underlying demand estimated by PCR in Java and that a certain portion of this market will continue to be met by captive installations for some time, PCR also determined what it considered realistic targets of sales on which PLN

a/ Includes Jakarta at 20.5%.

1/ The demand PLN would have served if its installations had been adequate and all self-supplied installations had been served by PLN.

could base its future development program. These are substantially lower than the underlying high market forecast, but of the same order of magnitude as an independent macro estimate which used per capita GNP projections 1/. These studies show that PLN's future sales, in the short and medium term, will depend entirely on the rate at which PLN is capable of satisfying an increasing proportion of the existing demand whereas, in the long term, sales are expected to reflect more closely the growth of the power market based on the overall level of economic development. The demand forecast used in this study is based on PLN's growth of sales. All forecasts are given in Table 1.

Forecasts of Future Generation Requirements (GWh)

Year (1)	PCR (High) (2)	PCR (Low) (3)	IAEA (Low) (4)	PLN/IBRD a/ (1978) (5)
1979	13,826	7,500	-	5,780
1980	16,078	9,728	9,165	7,005
1981	18,538	11,639	-	8,491
1982	21,513	13,285	12,926	10,291
1983	24,894	15,054	-	12,388
1984	27,212	16,999	-	14,771
1985	31,393	19,198	20,142	17,332
1986	36,187	21,646	-	20,478
1987	41,684	24,370	-	22,643
1988	47,986	27,393	-	36,039
1989	55,266	30,739	-	29,945
1990	53,669	34,439	43,400	34,437

1/ By the International Atomic Energy Authority in 1976.

a/ The figure in this column are for PLN's fiscal year which ends in March of the succeeding year. To compare with the figures in the preceding columns, they should be decreased by about 5% up to 1984, and 4% thereafter.

The Java demand forecast is determined at three voltage levels, high, medium and low, assuming that the degree of interconnection is sufficient to treat the three grids: West, Central and East Java, as a single system, during the time horizon 1979-87.

The system peak demand at the generators is determined by taking PLN's current energy forecast and applying the projected load factor of 0.68. As shown in Tables 1 to 3 and the accompanying Figure 3, the peak demand at each lower voltage level is estimated by deducting the system losses and consumer demand drawn off directly at the higher voltage level. The HV and LV peaks coincide with the system peak (approximately from 1800 to 1900 hours in the evening, as described later). The contribution of MV consumers to the system peak demand is estimated to be about 0.5 of their own peak demand (which occurs during the day-time).

Typical daily load duration curves for West, Central and East Java, and the composite all Java annual LDC's are given in Figures 4 to 8. The system peak occurs everywhere at or around 1900 hours.

No significant seasonality was observed (e.g., wet versus dry season) with reference to either the magnitude of the peak, or the shape of the LDC as shown in Figure 8. Therefore, the principal variation in the demand for power is by time of day, and it is assumed that the evening peak, caused mainly by residential consumers, would remain the dominant one within the time horizon 1979-87. The rapid growth of HV demand at high load factor would increase the demand uniformly throughout the day, while the MV demand increase would not be sufficient to make the day peak the dominant one.

6.3 STRICT LRMC COMPUTATIONS (JAVA)

The LRMC calculation consists of the following components:

1. peak capacity cost
2. peak energy cost
3. off-peak energy cost
4. customer costs

All cost have to be adjusted for losses up to the point of delivery to consumers. Capacity costs per kW are converted to costs per kW per year, by annuitizing over the lifetime of the equipment.

The costs are computed in constant 1978/9 Rupiah (Rp.), at border prices (BP). In the light of inadequate data, a relatively simple shadow pricing framework is applied. The new official exchange rate (OER) of Rp. 625 per US$ is used to convert foreign costs to Rp. (in BP). Local costs are converted to BP by the conversion factor(CF) 0.78 [1/] The total costs (i.e., foreign plus local) in BP are transformed into domestic priced (DP) costs by dividing by the standard conversion factor (SCF), which is assumed to 1.0 following the devaluation. For comparison, the costs without shadow pricing are also shown. The discount factor is 12% (opportunity cost of capital, OCC).

		% of Local Costs		Conv. Fac.		
1/	Unskilled Labor	35	x	0.7	=	0.25
	Other	65	x	1	=	0.65
				Local Costs CF	=	0.9

Capacity costs per peak kW served are first determined at the voltage level they are incurred in. They are converted to costs per kW per year by annuitizing at 12% over the plant life-span. The capacity costs per kW per year at lower voltage levels are determined by dividing by the appropriate power loss factor (see Table 3), as described after Table 10.

Peak Capacity Costs: Generation

Consider the simplified annual load duration curve and demand forecast shown in Figures 1 and 2. The LRMC of capacity may be determined by asking the following question: what is the change in system capacity costs ΔC associated with a incremental increase ΔD in the long run peak demand (as shown by the shaded area of Figure 1 and the broken line $D + \Delta D$ in Figure 2). The capacity cost of generation would be $(\frac{\Delta C}{\Delta D})$ in present value terms, annuitized over the lifetime of the plant, and this figure must be adjusted for reserve margin and losses at the various voltage levels. Therefore, the increment of demand ΔD is marginal both in time, and in terms of kW.

In an optimally planned system, the change in the expansion program to meet the new incremental load would normally consist of advancing the commissioning date of new plant or inserting units such gas turbines or peaking hydro. In the case of Java, the generating system is imbalanced at present, 1/ e.g., in 1977/1978, there was almost 600 MW of gas turbines out of a total installed capacity of about 1300 MW (dependable capacity, only 1060 MW). Consequently, gas turbines are currently being used to serve base load. Therefore, to restore the normal generating balance, during the period 1978/1979 to 1983/1984, about 1500 MW of base load steam plant will be added to the system. This will lead to large reserve margins during this period, sometimes exceeding 35% of the installed capacity.

The fuel savings alone from displaced gas turbines, will help to justify these base load plant additions. Consequently an incremental block of peak period customers (as shown in Figures 1 and 2) can be served at essentially zero capacity cost, from gas turbines which have been freed. New peaking capacity will be required only by about 1984, when the reserve margin will have become low and the Saguling hydro units will come on-stream (for peaking purposes).

Therefore, it may be deduced that the LRMC generation capacity cost will be represented by the costs of Saguling, but discounted to the present time, appropriately annuitized, corrected for losses and so on. The average costs of the first 175 MW unit from Table 4 is used to calculate the generation capacity costs per kW per year at HV, MV and LV.

1/ During the late 1960's and early 70's, a large amount of gas turbines were commissioned because these were the only type of plant which could be added on fast enough to meet the growth of demand at that time, which had not been foreseen earlier when PLN was institutionally weak.

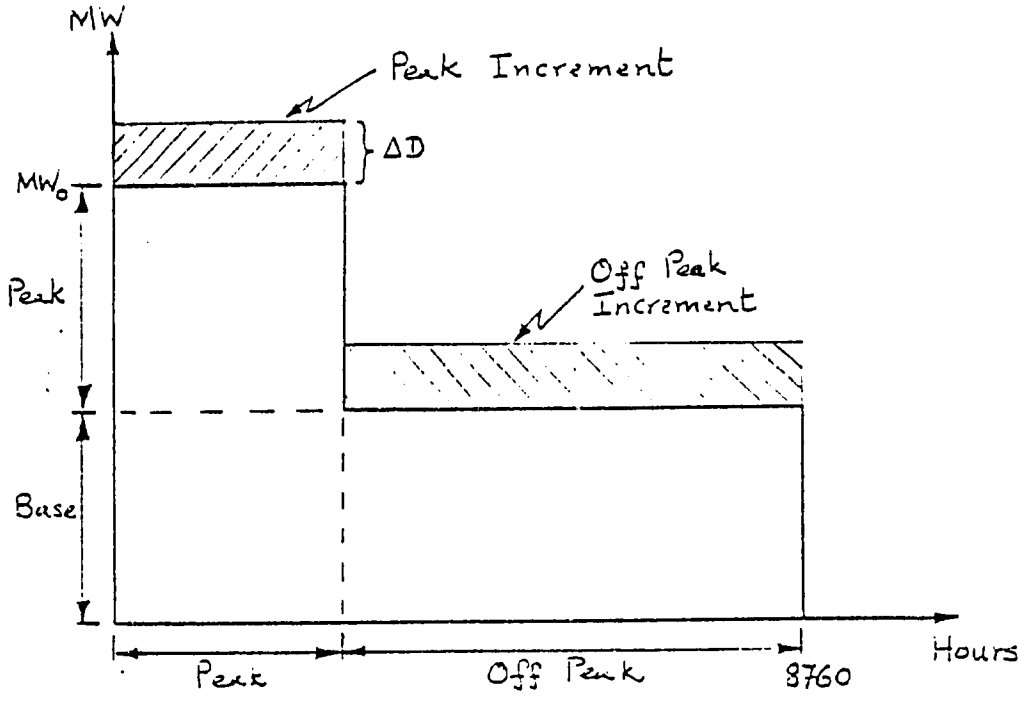


Figure 1. Simplified Load Duration Curve (LDC)

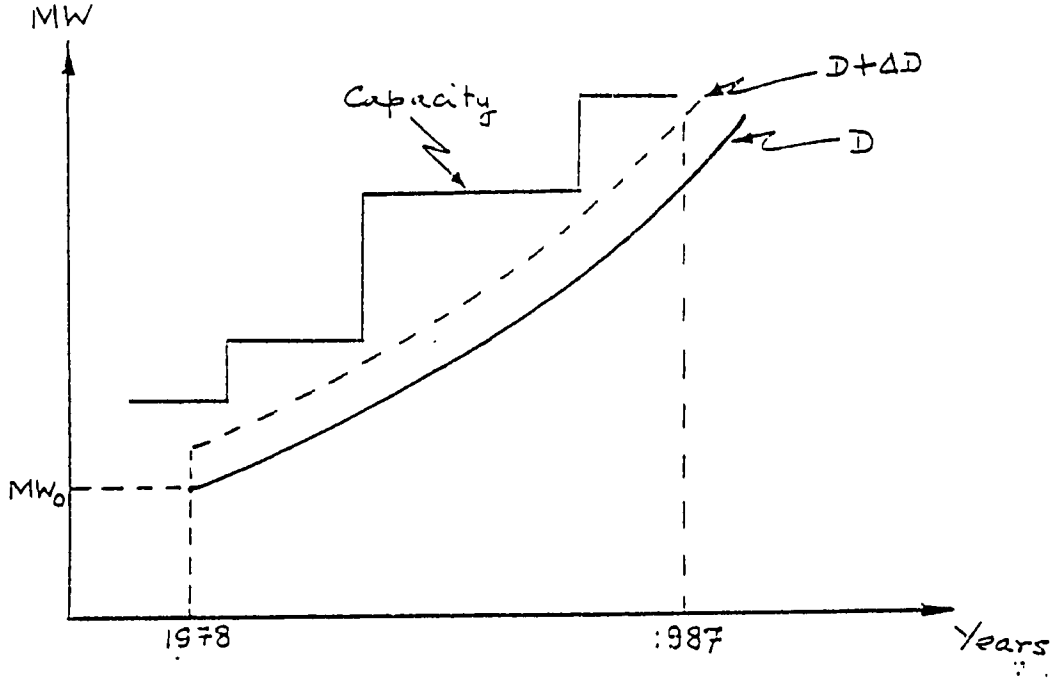


Figure 2. Projection of Peak MW Demand

Peak Capacity Costs: Transmission and Distribution

All transmission and distribution (T & D) investment costs are allocated to capacity (or kW) costs. The present discounted value of T & D costs per kW of serving incremental consumers may be computed using the Average Incremental Cost (AIC) method, i.e., the (discounted) ratio of future investment costs to incremental kW served. 1/

Transmission investment costs at EHV/HV are computed from the transmission investment plan, as shown in Tables 5a, and 5b. Distribution investment costs are allocated between MV and LV levels, as given in Tables 6 to 8. The incremental costs and demand at each voltage level, are also given in TAbles 6 to 8. The incremental costs and demand at each voltage level are summarized in Table 9. The average incremental cost (AIC) is calculated as the ratio of the above quantities, for transmission and distribution.

Total Peak Capacity Costs

These are summarized in Table 10 in domestic prices. The method of derivation is shown in the next sheet.

Other Costs: O & M, G & A, Facilities

These costs are taken from PLN financial projections and calculated as costs per kW per year. Ideally, they should be opportioned between kW and kWh costs.

However, since these costs are small, (e.g., a few percent of investment costs) and no accurate data on allocation is available, they are all opportioned to capacity costs of generation, transmission and distribution and computed as whown in Tables 11 to 16 on a per kW per year basis.

Energy Costs: Peak

The energy costs of meeting a block of incremental peak consumers will essentially be the cost of running the gas turbines. Even after 1984, when the peaking hydro at Saguling has come on stream, gas turbines will still need to be run as the marginal units. Owing to the variations in fuel prices, the cost per kWh of generation has been computed using 2 values for high speed diesel (HSD) costs: US$ 15.5 and 13 per barrel, (international prices).

The long run marginal energy costs during the off-peak period shown by the shaded block of kWh in Figure 1, would be the costs of running the marginal base load steam plant (e.g., the Muara-Karang units). 1/ The cost per kWh has been computed using 2 prices for Bunker C Fuel corresponding to the HSD prices, i.e., U.S.$ 12 and 10 per barrel.

1/ Suppose ΔMW_i and I_i are the incremental demand served and the corresponding investment cost in year i. Then, the AIC of capacity is given by:

$AIC = \sum_{i=1}^{T} [I_i / (1+r)^i] / [\sum_{i=1}^{T} \Delta MW_i / (1+r)^i]$ where r is the discount rate (e.g. the opportunity cost of capital) and T is the time horizon (e.g., 10 years).

Typical calculations for both peak and off-peak energy costs are summarized in Tables 17a, 17b, 18 and 19, at HV. MV and LV levels.

Customer Costs

These are available from PLN costs, i.e., connection labor costs, meter costs, service drop line costs, etc.

The costs of meter reading and billing etc. are already included in A & G costs.

Java Basic LRMC

These results are summarized in Table 20. The capacity costs have been converted to equivalent kWh costs assuming different consumer coincidence and load factors in Table 21.

LRMC Outside Java

Ideally, the LRMC for each of the islands should be computed separately (as for Java) because the system parameters are widely different in each case. However, this was not done, because the available data on demand, investment and operating costs, losses etc. is unreliable.

Figure 3.

DIAGRAM FOR TABLE I : LOAD/DEMAND & LOSSES FORECAST M.W.

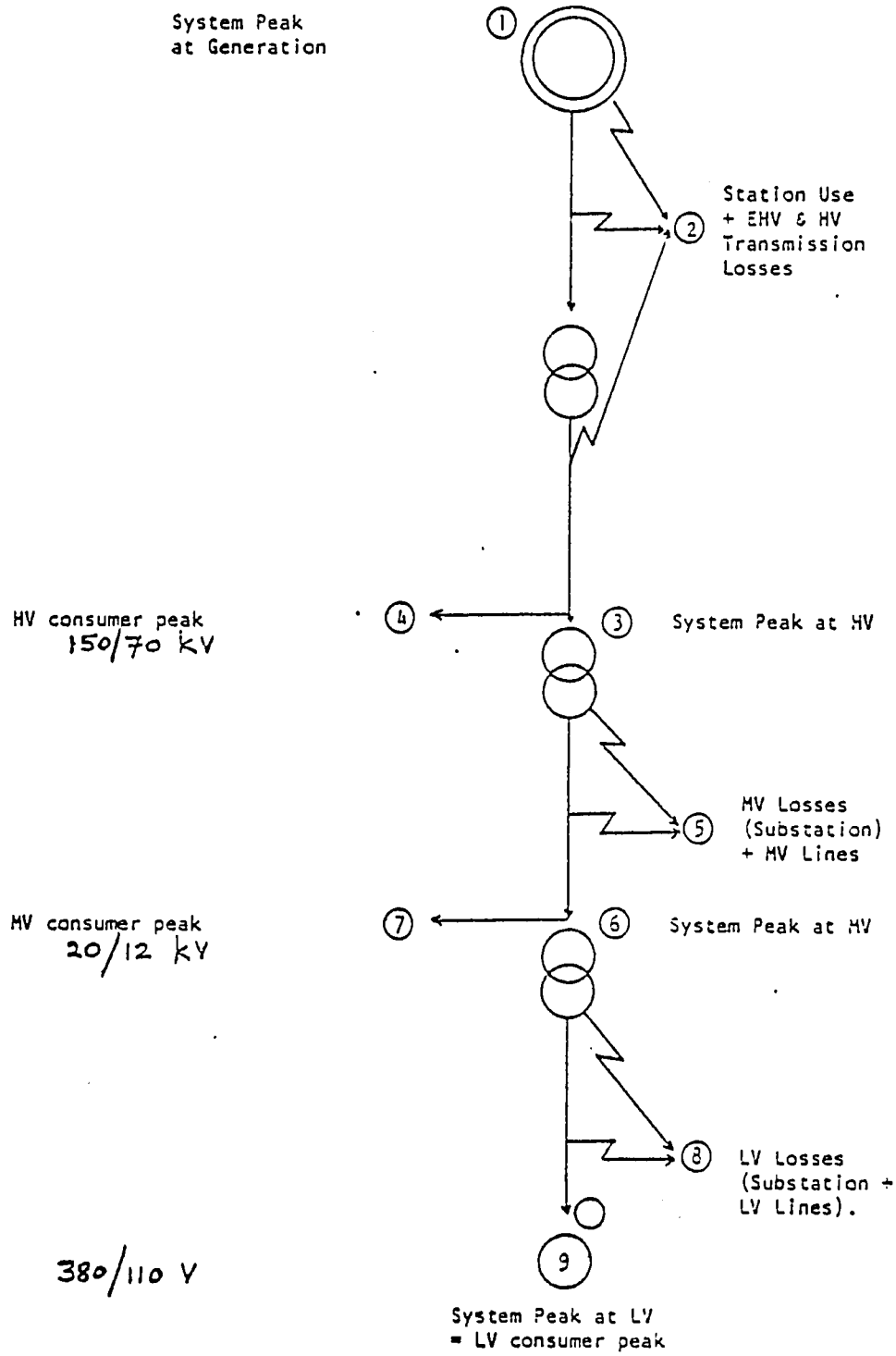


Table 1a.

LOAD FORECAST FOR JAVA
PEAK GENERATION

YEAR	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	
G.W.H.	3.909	4.769	5.780	7.005	8.491	10.291	12.388	14.771	17.332	20.478	
M.W.	656,2	800,6	970,3	1.175,9	1.425,4	1.727,6	2.079,6	2.479,7	2.909,6	3.437,8	

Note :

$$M.W. = \frac{G.W.H}{8,76 \times L.F}$$

L.F. = 0,68

TABLE : 1b

JAVA DEMAND AND LOSS FORECAST AT TIME OF SYSTEM PEAK

Unit : MW

YEAR	Syst. peak at generation (MW).	Station use EHV & HV Transmission loss.	System Peak at HV	HV Consumer peak	MV losses (subst. + MV Lines)	System Peak at MV	MV Consumer peak		LV losses (subst. + Lines).	System Peak at LV.
							at system peak time	own peak		
	(1)	(2)	(3)=(1)-(2)	(4)	(5)	(6)=(3)-(4)-(5)	(7)a	(7)b	(8)	(9)=(6)-(7)a-(8)
77/78	656,2	63,98	592,2	13,00	52,13	527,07	60,55	121,10	155,23	315,15
78/79	800,6	82,06	718,54	43,76	60,73	614,05	69,86	139,71	179,58	364,61
79/80	970,3	106,73	863,57	68,13	71,59	723,85	88,68	177,35	200,08	435,09
80/81	1175,9	135,23	1040,67	146,4	80,48	813,79	97,24	194,47	225,71	490,84
81/82	1425,4	174,61	1250,79	196,51	94,89	959,39	123,18	246,35	250,86	585,35
82/83	1727,6	220,27	1507,33	229,27	95,86	1182,2	165,82	331,64	304,91	711,47
83/84	2079,6	280,75	1798,85	262,02	115,26	1421,57	220,45	440,90	342,32	858,80
84/85	2479,7	347,16	2132,54	294,77	137,83	1699,94	288,93	577,85	402,14	1008,87
85/86	2909,6	407.34	2502,26	327,52	163,11	2011,63	374,80	749,60	441,94	1194,89
86/87	3437,8	481,29	2956,51	360,27	194,72	2401,52	447,68	895,36	527,54	1426,30

JAVA INCREMENTAL DEMAND FORECAST
AT TIME OF SYSTEM PEAK
(derived from Table 1)

TABLE : 2

In constant : MW

Year	Discount Factor (A)	Gener. Peak (1)	Gener Increment (B)	Gen. Incr. Discount (A)x(B)	MV Peak (3)	MV Increment (C)	MV Incr. Discount (A)x(C)	HV Peak (6)	HV Increment (D)	HV Incr. Discount (A)x(D)	LV Peak (8)	LV Increment (E)	LV Incr. Discount (A)x(E)
76/77													
77/78		656,2			592,2			527,07			315,15		
78/79	1	800,6	144,4	144,4	718,54	126,34	126,34	614,05	86,98	86,98	364,51	49,46	49,46
79/80	0,8929	970,3	169,7	151,53	863,57	145,03	129,50	723,85	109,8	98,04	435,09	70,48	62,93
80/81	0,7972	1175,9	205,6	163,90	1040,67	177,1	141,18	813,79	89,94	71,70	490,84	55,75	44,44
81/82	0,7118	1425,4	249,5	177,59	1250,79	210,12	149,56	959,39	145,6	103,64	585,35	94,51	67,27
82/83	0,6355	1727,6	302,2	192,05	1507,33	256,54	163,03	1182,2	222,81	141,60	711,47	126,12	80,15
83/84	0,5674	2079,6	352	199,73	1798,85	291,52	165,41	1421,57	239,37	135,82	858,80	147,33	83,60
84/85	0,5066	2479,7	400,1	202,69	2132,54	333,69	169,05	1699,94	278,37	141,02	1008,87	150,07	76,03
85/86	0,4523	2909,6	429,9	194,44	2502,26	369,72	167,22	2011,63	331,69	140,98	1194,89	186,02	84,14
86/87	0,4039	3437,8	528,2	213,34	2956,51	454,25	183,47	2401,52	389,89	157,48	1426,30	231,41	93,47
TOTALS				1639,67			1394,76			1077,26			641,49

LOSSES

TABLE : 3

Av. & Peak Loss. Factors for Energy/Power (% of In Coming)

(Peak losses used in Table 1)

Year	Station Use	EHV/HV (Av. E/P)	Stat Use + EHV/HV		HV Losses		LV Losses		Total Losses as a % of generation
			Av.E/P	Peak P	Av.E/P	Peak P	Av.E/P	Peak P	Av.E/P
	(1)	(2)	(3)	(4) (A)	(5)	(6) (B)	(7)	(8) (C)	(9)
77/78	3	4,5	7.5	9,75	6	9	22	33	24,9
78/79	3,5	4,5	8	10,25	6	9	22	33	23,6
79/80	3,5	5	8,5	11,00	6	9	21	31,5	21,8
80/81	4	5	9	11,50	6	9	21	31,5	21,2
81/82	4	5,5	9,5	12,25	6	9	20	30	21,2
82/83	4,5	5,5	10	12,75	5	7,5	20	30	21,2
83/84	4,5	6	10,5	13,50	5	7,5	19	28,5	21,1
84/85	5	6	11	14,00	5	7,5	19	28,5	21,4
85/86	5	6	11	14,00	5	7,5	18	27	20,9
86/87	5	6	11	14,00	5	7,5	18	27	20,7

3 = 1 + 2

4 = 1 + α * 2

6 = α + 5

8 = α + 7

$\alpha = \frac{\text{peak MW}}{\text{av. MW}} \approx 1,5$

9 = Total average losses according to program (% of generation)

Av. = average

E = Energy loss

P = Power loss

FIGURE 4

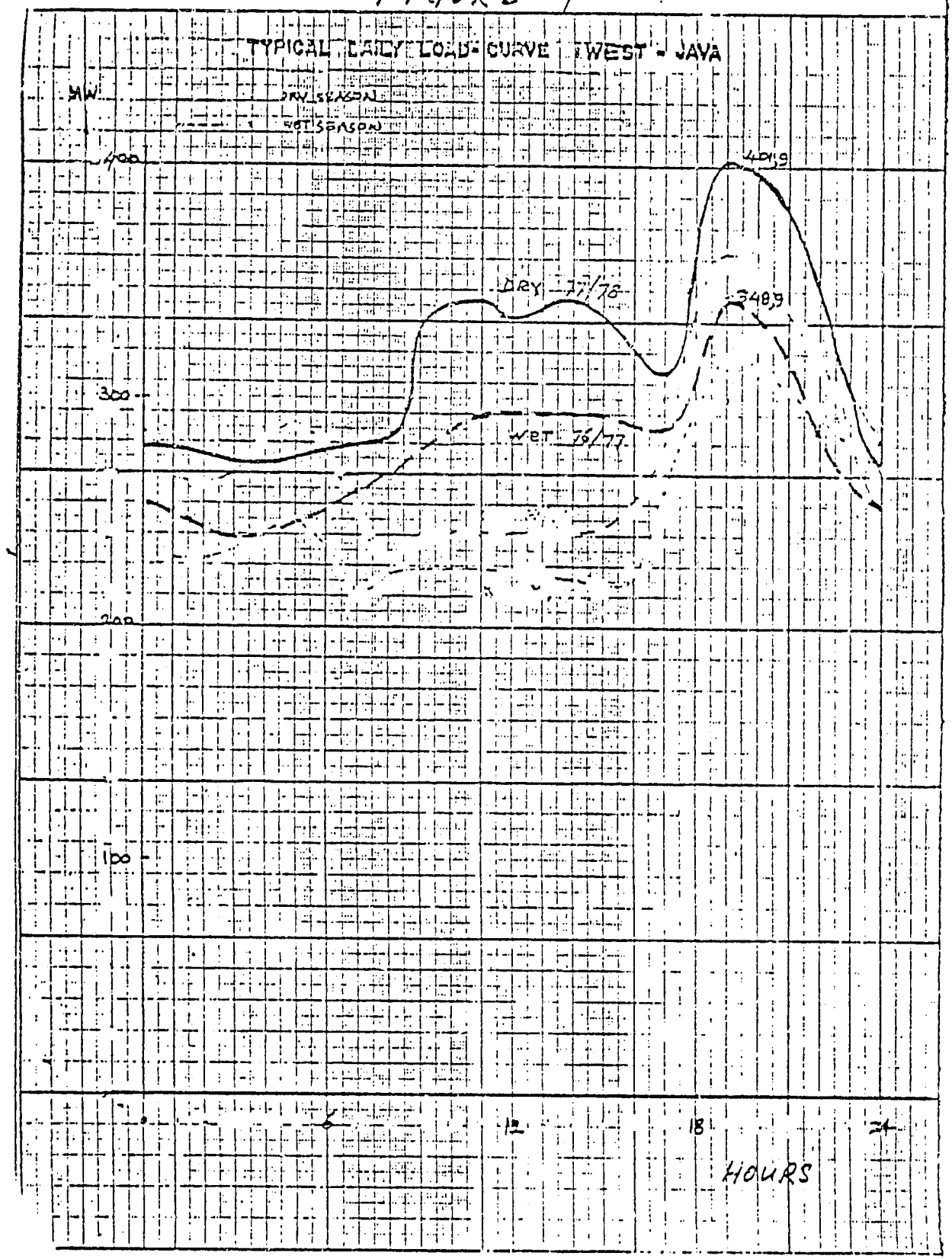

TYPICAL DAILY LOAD-CURVE WEST - JAVA
MW
DRY SEASON
WET SEASON
400
300
200
100
401,9
348,9
DRY 77/78
WET 76/77
12
18
24
HOURS

FIGURE 5

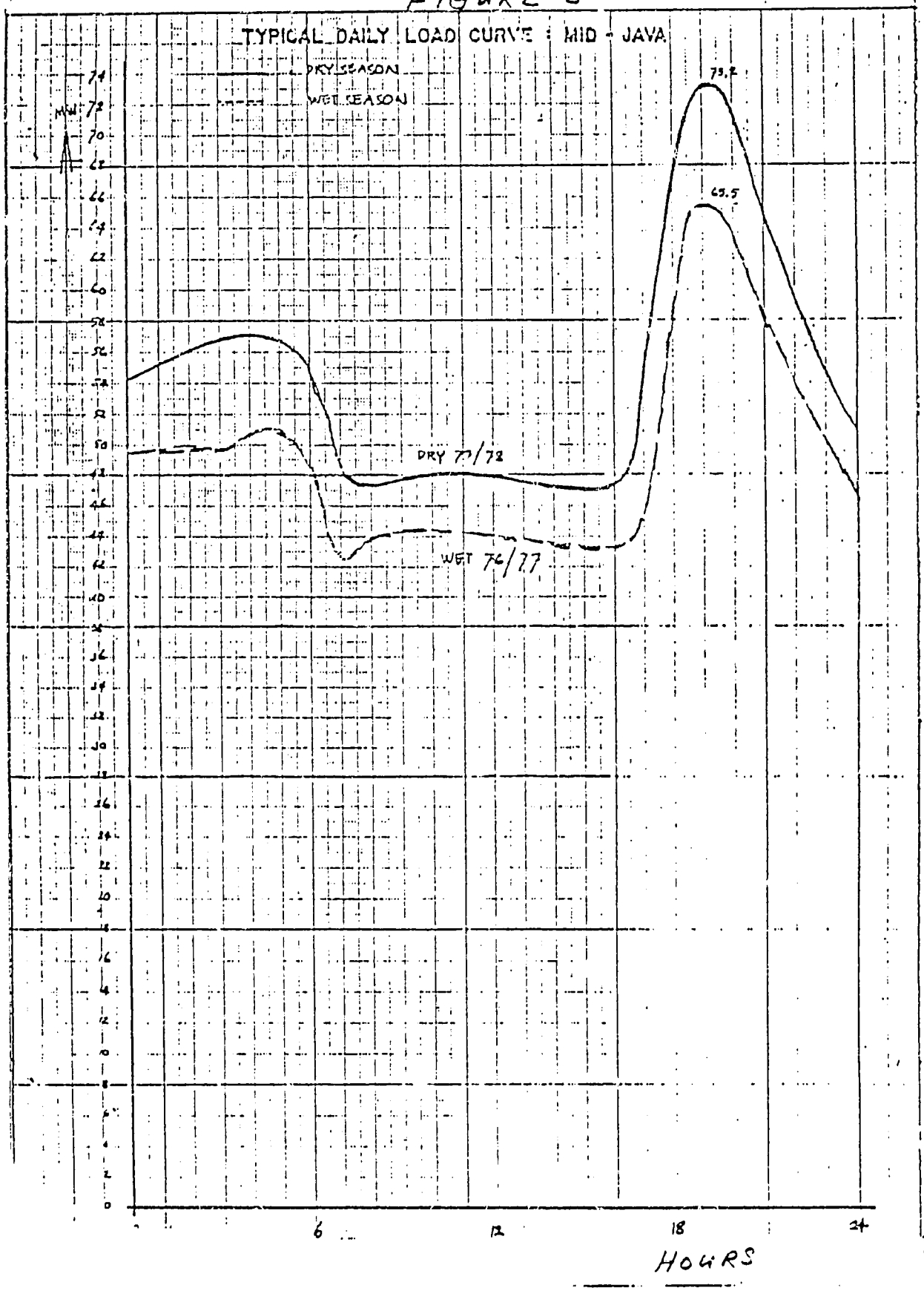

TYPICAL DAILY LOAD CURVE : MID - JAVA
DRY SEASON
WET SEASON
MW
73.2
65.5
DRY 77/78
WET 76/77
6
12
18
24
HOURS

FIGURE 6

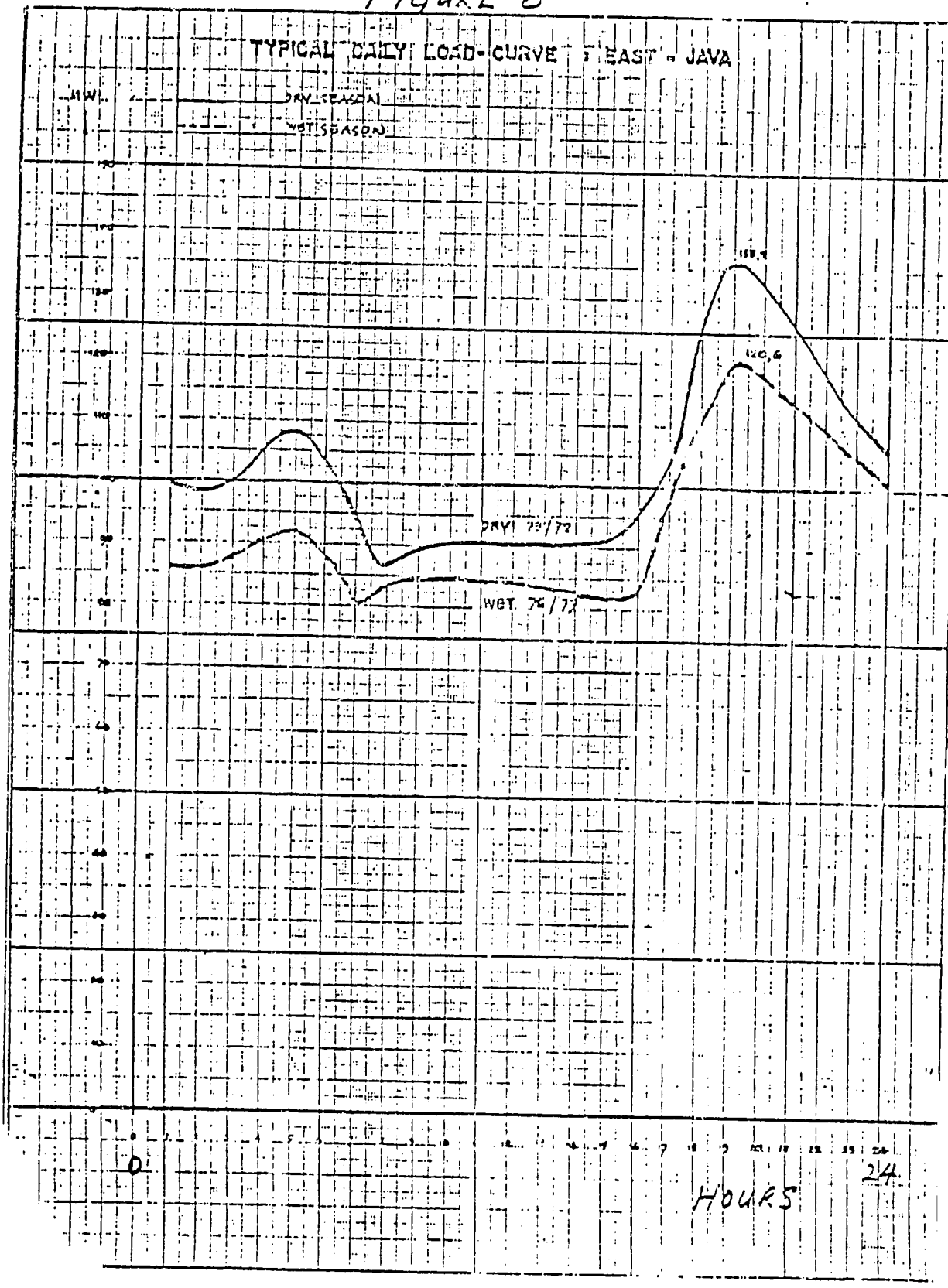
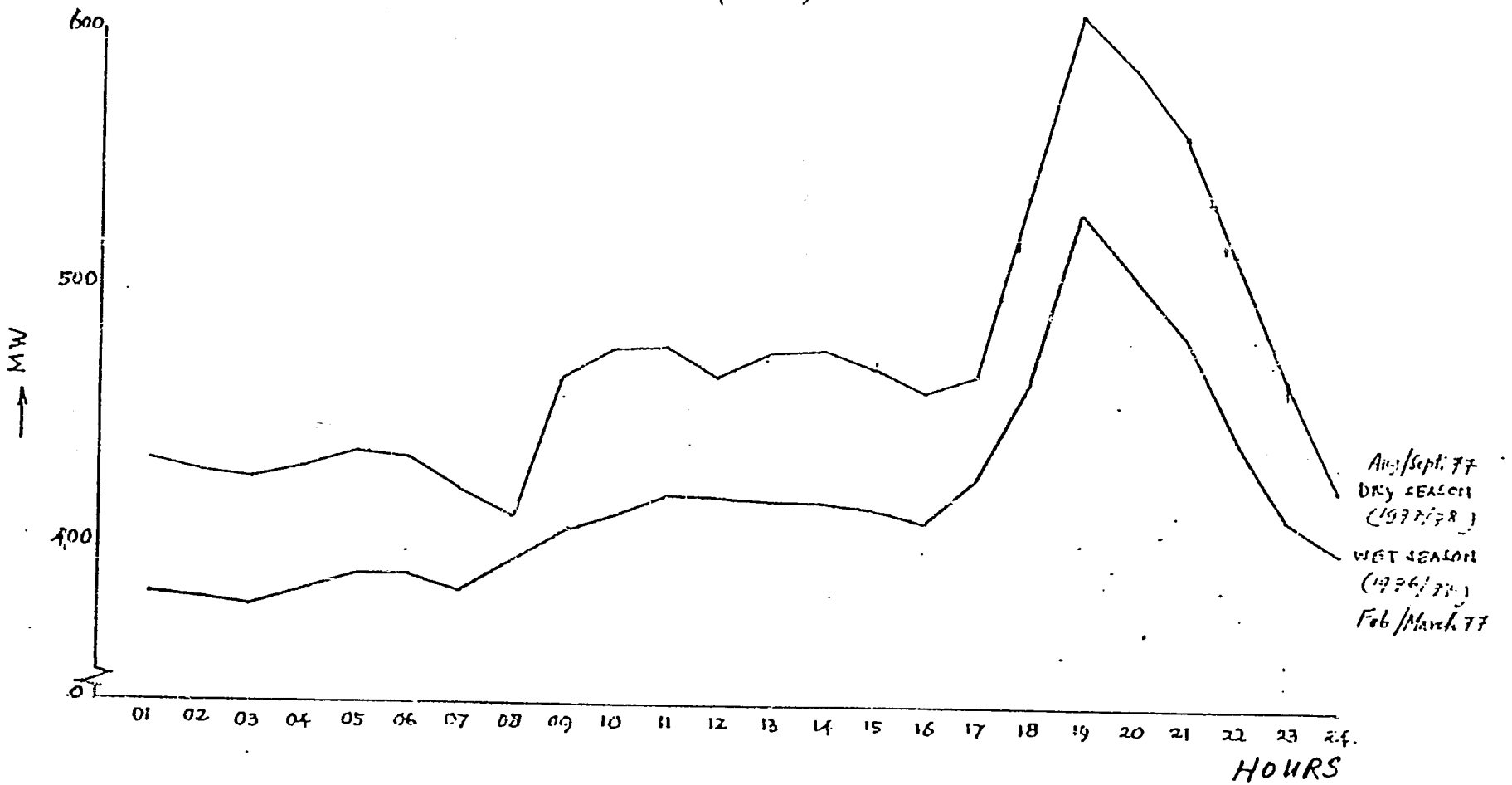

TYPICAL DAILY LOAD-CURVE EAST - JAVA
MW
DRY SEASON
WET SEASON
118,4
120,6
DRY 73/72
WET 74/73
0
24
HOURS

FIGURE 7
TOTAL LOAD CURVE (JAVA)



PLN Fiscal Year: (April 1 to March 31).

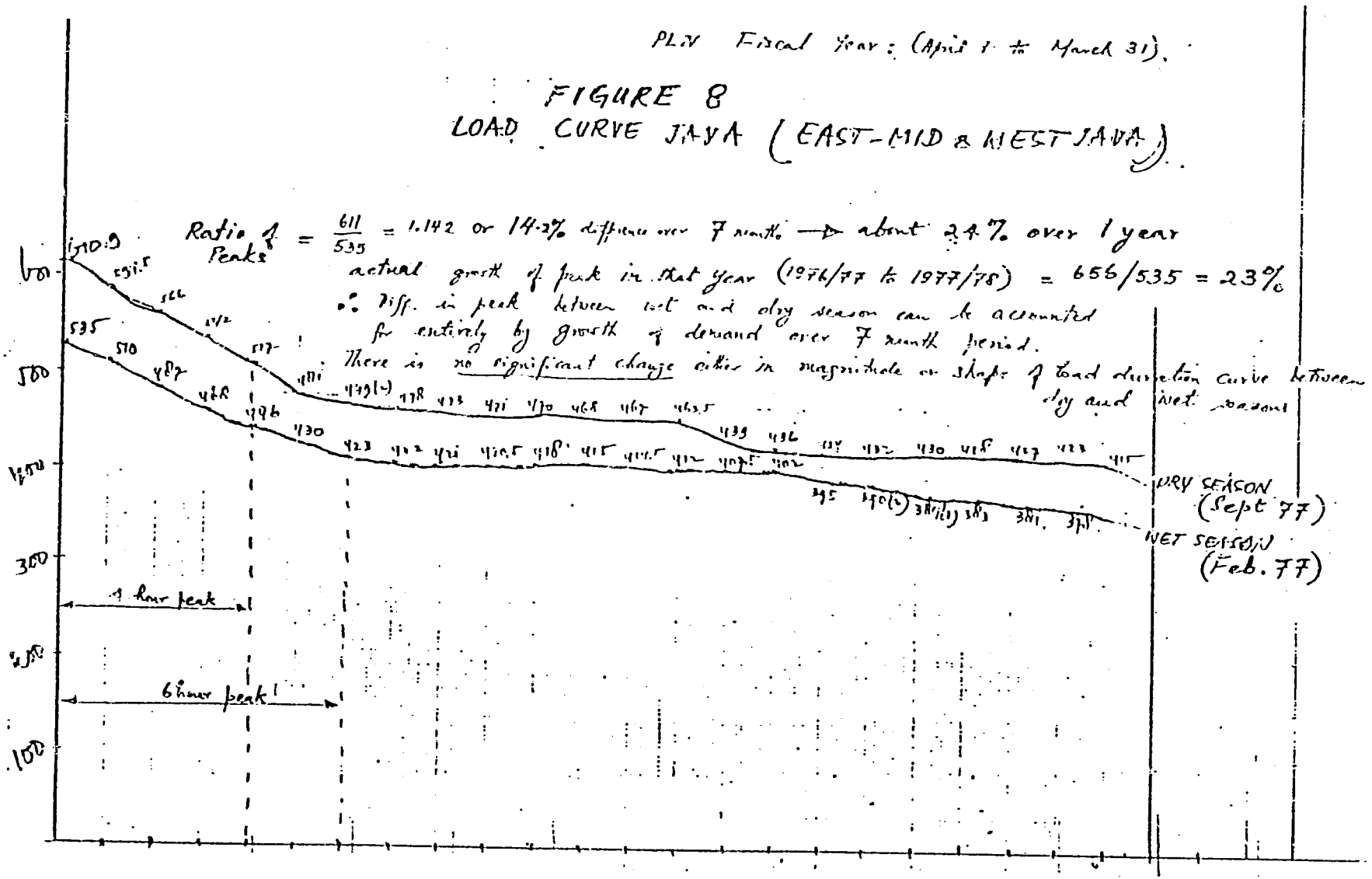
FIGURE 8
LOAD CURVE JAVA (EAST-MID & WEST JAVA)

Ratio of Peaks $= \frac{611}{535} = 1.142$ or 14.2% difference over 7 months → about 24% over 1 year

actual growth of peak in that year (1976/77 to 1977/78) = 656/535 = 23%

∴ Diff. in peak between wet and dry season can be accounted for entirely by growth of demand over 7 month period.

There is no significant change either in magnitude or shape of load duration curve between dry and wet seasons



GENERAL CAPACITY COST FOR Δ PEAK
(GENERATION INVESTMENT PLAN OF JAVA)
(SAGULING HYDRO PLANT 1st UNIT of 175 MW)

Table : 4

Rp. 10^9

Year	Foreign	Local	No Shadow Price Total	Shadow Price Local	Shadow Price Total	Discount Factor	No Shadow Pricing Discount Total	Shadow Pricing Discount Total (BP)
	(1)	(2)	(3)=(1)+(2)	(4)=(2)x(0,9)	(5)=(1)+(4)	(6)	(7)=(3)x(6)	(8)=(5)x(6)
78/79	2,1	2,04	4,14	1,94	3,94	1	4,14	3,94
79/80	6,15	3,-	9,15	2,7	8,85	0,8929	8,17	7,9
80/81	7,65	5,04	12,69	4,54	12,19	0,7972	10,12	9,72
81/82	10,2	3,72	13,92	3,35	13,55	0,7118	9,91	9,64
82/83	7,65	3,-	10.65	2,7	10.35	0,6355	6,77	6,5[illegible]
83/84	4,05	2,04	6,09	1,84	5,89	0,5674	3.46	3,34
84/85	2,1	0,96	3,06	0,86	2,96	0,5066	1,55	1,50
85/86								
86/87								
Total	39,9	19,8	59,7	17,82	57,72	-	44,12	42,61

Note : - 50% of the Dam Cost = 6,75 % of total cost, allocated to capacity costs.
(Dam Cost = 13,5 % total Saguling Cost).

- Hence the Cap Cost = Total cost x 0,09325
No shadow pricing discount total = 44,12 x 0,9325 = 41,14
Shadow pricing discount total = 42,61 x 0,9325 = 39,73

CALCULATION OF GENERATION COMPONENT CAPACITY
COST FOR Δ PEAK (JAVA)
SAGULING HYDRO PLANT 1st UNIT 175 MW

A. SHADOW PRICED

1. Generation Δ peak.

a. HV Consumer $= \frac{39.23 \times 10^9 \text{ Rp.}}{175 \times 10^3 \text{ kW}} \div 1 \times 1,2 \div 0,927$

Per kW = Rp.293.888/kW

Per kW/year = Rp.293.888/kW x 0,120925 (annuity factor)

= Rp.35.538/kW/year (DP)

b. M.V. Consumer :

Per kW = Rp.293.888/kW ÷ 0,918

= Rp.320139/kW

Per kW/year = Rp.320.139/kW x 0,120925 *)

= Rp.38.713/kW/year (DP)

c. L.V. Consumer :

Per kW = Rp.320.139/kW ÷ 0,7

= Rp.457.341

Per kW/year = Rp.457.341/kW x 0,120925 *)

= Rp.55.304/kW/year (DP)

B. NOT SHADOW PRICED

a. H.V. Consumer $= \frac{41,14 \times 10^9 \text{ Rp.}}{175 \times 10^3 \text{ kW}} \times 1,2 \div 0,927$

Per kW = Rp.304.318/kW

Per kW/year = Rp.304.318/kW x 0,120925 *)

= Rp.36.799/kW/year

b. M.V. Consumer :

Per kW = Rp.304.318 ÷ 0,918

Rp.331.501 / kW

Per kW/year = Rp.331.501 / kW x 0,120925 *)

= Rp.40.086.-

c. L.V. Consumer :

Per kW = Rp.331.501/kW ÷ 0,7

= Rp.473.572

Per kW/year = Rp.473.572/kW x 0,120925

= Rp.57.266. kW/year

Note : *) annuity factor (for generation) :

n = 35 + 8 = 43 years)
i = 12% = 0,12) ann.f. = 0,120925

0.927,0918,07 are power loss factors

1,2 is factor for 20% average reserve margin.

1,0 = SCF

Table 5a.

INVESTMENT PROGRAMME-JAVA
E.H.V./H.V. TRANSMISSION 1/

Rp. 10^9.

			78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	TOTAL 78-86	
1	TRANSMISSION	FC	11.50	16.80	13.10	14.60	27.80	27.30	15.00	7.00	10.50	143.6	
		LC	5.3	6.80	5.10	8.20	12.60	10.20	4.80	3.30	4.90	61.7	
2	SUBSTATION	FC	7.10	14.40	9.50	9.60	19.40	11.20	5.70	10.60	27.40	114.9	
		LC	2.60	3.40	1.90	3.60	4.40	2.20	1.20	3.90	7.40	30.6	
3	100% L.D.C. (Load Despatch Centre)	FC	-	2.08	3.45	1.77	2.06	1.67	1.67	1.67	1.67	16.04	
		LC	-	0.4	0.63	0.54	0.67	0.11	0.11	0.11	0.11	2.68	
4	T O T A L	FC	18.6	33.28	26.05	25.97	49.26	40.17	22.37	19.27	39.57	274.54	
		LC	8.4	10.6	7.63	12.34	17.67	12.51	6.11	7.31	12.41	94.98	

1/ Multiply all foreign costs (FC) by 1.5 and local costs (LC) by 1.2.

TRANSMISSION CAPACITY COSTS (HV COST)
(TRANSMISSION EHV/HV INVESTMENT PLAN).

Table : 5b

In constant Rp.10^9

year	Foreign	LOCAL	NO SHADOW Price Total	Shadow Price Local	Shadow Price Total	Discount Factor	No Shadow Pricing Discount Total	Shadow Pricing Discount Total (RP)
	(1)	(2)	(3)=(1)+(2)	(4)=(2)x0,9	(5)=(1)+(4)	(6)	(7)=(3) x(6)	(8)=(5)x(6)
78/79	27,9	10,08	37.98	9,07	36.97	1	37.98	36.97
79/80	49.92	12,72	62.64	11,45	61.37	0,8929	55.93	54.8
80/81	39.08	9.16	48.24	8.24	47.32	0,7972	38.46	37.72
81/82	38.95	14.81	53.76	13.33	52.28	0,7118	38.26	37.21
82/83	73.89	21.20	95.09	19.08	92.97	0.6355	60.43	59.08
83/84	60.25	15.01	75.26	13.51	73.76	0,5674	42.70	41.85
84/85	33.55	7.33	40.88	6.60	40.15	0,5066	20.71	20.34
85/86	28.90	8.77	37.67	7.89	36,79	0,4523	17.04	16.64
86/87	59.36	14.39	74.25	13.40	72.76	0,4039	29.99	29.39
TOTAL	411.80	113.97	525.77	102.57	514.37		341,5	334.-

Table 6a

INVESTMENT PROGRAMME JAVA
H.V. DISTRIBUTION 1/

Rp. 10^9.

			78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	TOTAL 78-86	
1	DISTRIBUTION MV - LINE	FC	5.36	7.46	9.08	10.41	11.89	11.96	13.20	18.59	9.84	96.89	
		LC	8.37	11.48	13.79	15.86	18.03	15.98	21.51	27.34	12.30	144.66	
2	100% D.C.C. (Distrib. Control Centre)	FC	-	1.25	2.08	1.25	1.04	-	-	-	-	5.62	
		LC	-	0.1	0.2	0.2	0.1	0.2	-	-	-	0.8	
3	60% T.M. LISTRIK-DESA	FC	-	1.13	1.13	1.13	1.29	1.29	1.29	1.29	1.29	9.84	
		LC	-	1.69	1.69	1.69	1.94	1.94	1.94	1.94	1.94	14.77	
1	TOTAL	FC	5.36	9.84	12.29	12.79	14.22	12.35	14.49	19.88	11.13	112.35	
		LC	8.37	13.27	15.68	17.75	20.07	18.12	23.45	29.28	14.24	160.23	

1/ Multiply all foreign costs (FC) by 1.5 and local costs (LC) by 1.2.

MV (DISTRIBUTION) COST
(MV INVESTMENT PLAN)

TABLE : 6b

In constant Rp.10^9

Year	foreign	Local	No Shadow Price Total	Shadow Price Local	Shadow Price Total	Discount Factor	No Shadow Pricing Discount Total	Shadow Pricing Discount Total (BP)	(DP)
	(1)	(2)	(3)=(1)+(2)	(4)=(2)x0,9	(5)=(1)+(4)	(6)	(7)=(3)x(6)	(8)=(5)x(6)	
78/79	8.04	10.04	18.08	9.04	17.08	1	18.08	17.08	
79/80	14.76	15.92	30.68	14.33	29.09	0.8929	27.39	25.97	
80/81	18.43	18.82	37.25	16.94	35.37	0.7972	29.69	28.2	
81/82	19.18	21.3	40.48	19.17	38.35	0.7118	28.81	27.3	
82/83	21.33	24.60	45.41	21.67	43.-	0.6355	28.86	27.33	
83/84	18.53	21.74	40.27	19.56	38.09	0.5674	22.85	21.61	
84/85	21.73	28.14	49.87	25.33	47.06	0.5066	25.26	23.84	
85/86	29.82	35.14	64.96	31.63	61.45	0.4523	29.38	27.79	
86/87	16.70	17.09	33.79	15.38	32.08	0.4039	13.65	12.96	
Total	168.52	192.27	360.79	173.05	341.57		223.97	212.08	

Table 7

INVESTMENT PROGRAME JAVA

L.V. DISTRIBUTION. 1/

In constant Rp 10^9

			78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	TOTAL 78-86	
1	DISTRIBUTION	FC	7.47	10.40	12.56	14.53	16.59	15.42	18.41	25.93	13.73	139.69	
	LV - LINE	LC	11.67	16.01	19.24	22.13	25.16	22.29	30.01	38.14	17.16	209.03	
2	DISTRIBUTION TRANSFORMER + RURAL E.TRANSF.	FC	18.93	22.37	27.53	33.83	41.57	48.91	56.61	65.26	74.24	388.35	
		LC	4.51	5.6	6.88	8.46	10.39	12.23	14.15	16.32	18.56	97.1	
3	72% P.T.R.	FC		1.17	0.94	0.94	1.02	1.02	1.02	1.02	1.02	8.15	
		LC		1.69	1.36	1.15	1.47	1.47	1.47	1.47	1.47	11.55	
4	60% (TR.LISTRIK-DESA + SAMBUNGAN RUMAH).	FC		1.22	1.45	1.69	2.09	2.47	2.47	2.47	2.47	16.33	
		LC		1.5	1.73	1.97	2.42	2.79	2.79	2.79	2.79	18.78	
5	TOTAL	FC	25.5	35.16	42.58	50.99	61.27	67.82	78.51	94.68	91.46	547.97	
		LC	16.18	24.8	29.21	33.71	39.44	38.78	48.42	58.72	39.98	329.24	

1/ Multiply all foreign costs (FC) by 1.5 and local costs (LC) by 1.2.

LV (DISTRIBUTION) COST
(LV INVESTMENT PLAN)
(JAVA)

TABLE : 8

in constant Rp.10^9

Year	Foreign Rp.	Local Rp.	Not Shadow Priced Total	Shadow Priced Local	Shadow Priced Total	Discount Factor	Not Shadow Priced Discounted Total	Shadow Priced Discounted Total (SP)	Shadow Priced Discounted (Domestic Prices)
	(1)	(2)	(3)=(1)+(2)	(4)=(2)x0,9	(5)=(1)+(4)	(6)	(7)=(3)x(6)	(8)=(5)x(6)	(8)
78/79	38.25	19.42	57.67	17.48	55.73	1	57.67	55.73	
79/80	52.74	29.76	82.5	26.78	79.52	0,8929	73.66	71.-	
80/81	63.87	35.05	98.92	31.54	95.41	0,7972	78.86	76.06	
81/82	76.48	40.45	116.93	36.40	112.88	0.7118	83.23	80.35	
82/83	91.90	47.33	139.23	42.59	134.49	0.6355	88.48	85.47	
83/84	101.73	46.54	148.27	41.88	143.61	0.5674	84.13	81.48	
84/85	117.76	58.10	175.86	52.29	170.05	0.5066	89.09	86.15	
85/86	142.02	70.46	212.48	63.41	205.43	0.4523	96.10	92.91	
86/87	137.19	47.97	185.16	43.17	180.36	0.4039	74.78	72.85	
Total	821.94	395.08	1.217.02	355.54	1.177.48	-	726.-	702.-	

TABLE 9

INCREMENTAL CAPACITY COST SUMMARY (BP)

A). SHADOW PRICED

		Increm. Costs	Increm. Demand	(BP) Ratio (AIC)
		Rp.10^9	10^3 kW	Rp.10^3/kW
1	GENERATION(△ PEAK SAGULING 1st UNIT)			Computed separately
2	TRANSMISSION HV	334,-	1,394.76	239.5 (AIC)
.3	M.V.DISTRIBUTION	212,03	1,077.26	196.9 (AIC)
4.	L.V.DISTRIBUTION	702	641.49	1094.0 (AIC)

B). NOT SHADOW PRICED

-		Rp. 10^9	10^3 kW	
1	GENERATION(△ PEAK SAGULING 1st UNIT			Computed separately
2	TRANSMISSION HV	341,5	1.394.76	244.8 (AIC)
3	M.V.DISTRIBUTION	223,97	1,077.26	207.9 (AIC)
4	L.V.DISTRIBUTION	726,-	641.49	1131.4 (AIC)

PEAK CAPACITY COST

(JAVA)

TABLE : 10

in constant Rp. 10^9

SUPPLY VOLTAGE	GENERATION (1)		TRANSMISSION EHV/HV (2)		PRIMARY DISTR. MV (3)		SECONDARY DISTR. LV (4)		T O T A L (5)	
1. Shadow Priced	per kW	per kW/ Year	per kW	per kW/ Year	per kW	per kW/ Year	per kW	per kW/ Year	per kW	per kW/ Year
a. HV (70/150kV)	293.888	35.538	239.467	30.532					533.355	66.070
b. MV (6/12/20kV)	320.139	38.713	260.857	33.259	196.869	25.100			777.865	97.072
c. LV (120 v/380V)	457.341	55.304	372.652	47.513	281.241	35.858	1.094.327	139.526	2.205.561	278.201
2. Not Shadow Priced										
HV (70/150 kV)	304.318	36.799	244.845	31.237					549.163	68.016
MV (6/12/20kV)	331.501	40.086	266.715	34.006	207.907	26.508			806.123	100.600
LV (120V/380V)	473.572	57.266	381.021	48.580	297.010	37.868	1.131.740	144.296	2.283.343	288.010

CAPACITY COST CALCULATION SUMMARY

A. Shadow Priced :

(1). Generation peak load

(a). HV ⟶ a (1) = Generation Cost of saguling (DP)

Rp.per kW

(b). MV ⟶ b (1) = [a. (1)] ÷ 0,918 Rp.per kW

(c). LV ⟶ c (1) = [b. (1)] ÷ 0,7 Rp.per kW

* To obtain Rp. per kW per Year = ...Rp. per kW times annuity factor

= Rp.per kW

(2). Transmission :

(a). HV ⟶ a (2) = $\frac{\text{HV Cost (BP)}}{\text{HV Incr. discount(MW)}}$ ÷ 1 (SCF)

(b). MV ⟶ b (2) = [a. (2)] ÷ 0,918

(c). LV ⟶ c (2) = [b. (2)] ÷ 0,7

* To abtain Rp. per kW per Year = ... Rp. per Year x 0,1223166

(3). Primary Distribution MV

(b). MV ⟶ b (3) = $\frac{\text{MV Cost (BP)}}{\text{MV Incr.,discount MW}}$ ÷ 1 (SCF)

(c). LV ⟶ c (3) = [b (3)] ÷ 0,7

* To abtain Rp./kW/Year = ...Rp. Year x 0,1241436

(4). Secondary Distribution LV :

(c). LV ⟶ c (4) = $\frac{\text{LV Cost (BP)}}{\text{LV Incr., discount MW}}$ ÷ 1 (SCF)

* To abtain Rp./kW/Year = ...Rp.per Year x 0,1241436

Note : 1 = Standard Conversion Factor (SCF)

BP = Border Prices

DP = Domestic Prices

0,918; 0,7 are power loss factors

0,9 = shadow price factor of the Local Costs

CALCULATION OF TRANSMISSION COMPONENT CAPACITY COST (JAVA)

A. SHADOW PRICED

2. TRANSMISSION

a. H.V. Consumer : $\frac{534 \times 10^9}{1.394,76 \times 10^3 \text{ kW}} \div 1$

Per kW = Rp.239.467 / kWh

Per kW/year = Rp.239.467 x 0,127500 (annuity factor) *

= Rp.30,532/kW/year

b. M.V. Consumer :

Per kW = Rp.239.467/kW ÷ 0,918

= Rp.260.857

Per kW/year = Rp.260.857/kW x 0,127500 *)

= Rp.33.259/kW/year

c. L.V. Consumer :

Per kW = Rp.260.857 ÷ 0,7

= Rp.372.652 / kW

Per kW/year = Rp.372.652/kW x 0,127500 *)

= Rp.47,513 / kW/year

B. NOT SHADOW PRICED

a. H.V. Consumer = $\frac{341.5 \times 10^9 \text{ Rp.}}{1.394,76 \times 10^3 \text{ kW}}$

Per kW = Rp.244.845 /kW

Per kW/year = Rp.244.845/kW x 0,127500 *)

= Rp.31.217/kW/year

b. M.V. Consumer :

Per kW = Rp.244.845/kW ÷ 0,918

= Rp.266.715/kW

Per kW/year = Rp.266.715/kW x 0,127500 *)

= Rp.34.006 / kW/year

c. L.V. Consumer :

Per kW = Rp.266.715.kW ÷ 0,7

= Rp.381.021/kW

Per kW/Year = Rp.381.021/kW x 0,127500 *)

= Rp.48.580/kW/year

NOTE :

*) annuity factor (for transmission)

n = 25 years)
i = 12 %) annuity factor = 0,127500

CALCULATION OF M.V. DISTRIBUTION COMPONENT CAPACITY COST (JAVA)

A. SHADOW PRICE

3. PRIMARY DISTRIBUTION MV.

b. MV. Consumer : $\frac{212,08 \times 10^9 Rp}{1.077,26 \times 10^3 kW} \div 1$

Per kW = Rp. 196.869,-/kW

Per kW/year = Rp. 196.869,- x 0,127500 (annuity factor) *)

= Rp. 25.100,- kW/year

c. L.V. Consumer :

Per kW = Rp. 196.869,-/kW ÷ 0,7

= Rp. 281.241,-/kW

Per kW/year = Rp. 281.241,-/kW x 0,127500 *)

= Rp. 35.858,- kW/year

B. NOT SHADOW PRICE

b. M.V. Consumer : $\frac{223,97 \times 10^9 Rp}{1.077,25 \times 10^3 kW}$

Per kW = Rp. 207.907,-/kW

Per kW/year = Rp. 207.907/kW x 0,127500 *)

= Rp. 26.508 kW/year

C. L.V. Consumer :

Per kW = Rp. 207.907,-/kW ÷ 0,7

= Rp. 297.010,-/kW

Per kW/year = Rp. 297.010,-/kW x 0,127500 *)

= Rp. 37.868,- kW/year

NOTE

*) annuity factor (for M.V. Distribution)

n = 25 years
i = 12 %
} annuity factor = 0,127500

CALCULATION OF L.V. DISTRIBUTION COMPONENT CAPACITY COST (JAVA)

A. SHADOW PRICE

4. SECONDARY DISTRIBUTION L.V.

c. L.V. Consumer : $\frac{702 \times 10^9 \text{ Rp.}}{641{,}49 \times 10^3 \text{ kW}}$ 1

Per Kw = Rp.1.094,327 / kW

Per kW/year = Rp.1.094,327 / kW x 0,127500 *)

= Rp.139.526 / kW/year

B. NOT SHADOW PRICE

c. L.V. Consumer : $\frac{726 \times 10^9 \text{ Rp.}}{641{,}49 \times 10^3 \text{ kW}}$

Per kW = Rp.1.131.740 / kW

= Rp.1.131.740/kW x 0,127500 *)

= Rp.144.296/kW/year

NOTE

*) annuity factor : (for L.V. Distribution)

n = 25 years) annuity factor = 0,127500
i = 12 %)

OPERATION & MAINTENANCE COST

(JAVA)

TABLE : 11

In constant Rp 10^9

	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	Total
(1) O & M	28.15	38.03	46.24	50.95	57.69	60	66.57	70.70	78.25	86.95	
(2) Increment Cost of O & M		9.88	8.21	4.72	6.74	2.30	6.57	4.13	7.55	8.5[illegible]	
(3) Discount factor		1	0.8929	0.7972	0.7118	0.6355	0.5674	0.5066	0.4523	0.4039	
(4) = (2) x (3) O & M Incr.discount		9.87	7.33	3.75	4.8	1.46	3.73	2.09	3.41	3.43	39.88

Total O & M Incr. Discounted Cost = 33,24 x 10^9 Rp.x1.2 = :

Note : The result of O & M is directly calculated in Rp./kW/Year
Without multiplying by the annuity factor, because O & M Cost is recurrent and used up within the Year.

		10^9 Rp.	10^9 MW
Generation	30%	11.96	1639.67
Transmission	12%	4.78	1394,76
MV Distr.	13%	5.18	1077.26
LV Distr.	45%	17,95	641.49
	100%	39.87	

OPERATION & MAINTENANCE COST

(JAVA)

TABLE : 12

in constant Rp x 10^9

Shadow Price / Supply Voltage	Generation (2) Per kW	Transmission EHV/HV (2) Per kW	Primary Distr. MV (3) Per kW	Secondary Distr. LV (4) Per kW	Total (5) Per kW
a. HV (70/150 kV) for peak/Saguling	7.870	3.432			11.302
b. MV (6/12/20 kV) for peak/Saguling	6.574	3.739	4.812		17.125
C. LV (120 V/380 V) for peak/Saguling)	12.248	5.341	6.875	27.984	52.448

GENERAL & ADMINISTRATION COST

(JAVA)

TABLE : 13

in constant 10^9 Rp.

	77/78	78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87	Total
(1) Gen. & Adm. Increment Cost	0.06	0.6	0.6	0.6	0.6	0.12	0.12	0.12	0.12	0.12	
(2) Insurance Increment Cost	0.08	0.34	2.77	- -	- -	0.17	0.25	0.67	0.50	0.50	
(3) Survey Incr.Cost	2.4	-	-	-	-	-	-	-	-	-	
(4) (1) + (2) + (3)	1.10	2.80	3.37	0.84	0.6	0.29	0.37	0.79	0.62	0.62	
Discount factor	1	0.8929	0.7972	0.7115	0.6355	0.5674	0.5066	0.4523	0.4039	0.3606	
= (3) x (4) Gen. & Adm. Incr.Disc	1.10	2.5	2.69	0.59	0.38	0.17	0.19	0.36	0.25	0.22	8.51

Total Gen. & Adm. incr. Disc. Cost =7,09 x 1,2 = 8.51

Note : The result of Gen.Adm.Cost is directly calculated in Rp./kW/Year.
Without multiplying by the annuity factor because Gen. & Adm. is recurrent and used up within the Year.

		10^9Rp.	10^3kW
Generation	30%	2.55	1639.67
HV Transmission part	12%	1.02	1394.76
MV Distribution part	13%	1.11	1077.26
LV Distribution part	45%	3.83	641.49
T o t a l	100%	8.51	

GENERAL & ADMINISTRATION COST

(JAVA)

TABLE : 14

in constant Rp 10^9

Shadow Price / Supply Voltage	Generation (1) Per kW	Transmission EVH/HV (2) Per kW	Primary D str. HV (3) Per kW	Secondary D. str. LV (4) Per kW	Total (5) Per kW
a. HV (Base 70/150 kV) for peak/Gas Turbine	1.681	731			2412
b. HV (Base 6/12/20 kV) for peak/Gas Turbine	1.831	796	1.025		3652
c. Base LV (120/V/380 V) for peak/Gas Trubine	2.616	1.138	1.464	5.967	11.185

FACILITIES COST

(JAVA)

TABLE : 15

$\pm$ in constant Rp.10^9

			78/79	79/80	80/81	81/82	82/83	83/84	84/85	85/86	86/87
(1) Facilities Cost (Increment)			9	12.24	11.21	11.71	12.07	12.56	12.56	12.56	12.56
(2) Discount factor			1	0.8929	0.7972	0.7116	0.6355	0.5674	0.5066	0.4523	0.4039
(3) (1) x (2)			9	10.93	8.94	8.34	7.67	7.13	6.36	5.69	5.07

Total Facilities Incr. Discounted Cost = 69.13

		10^9Rp.	10^3kW
Generation	30%	20.74	1.639,67
Transmission part (HV)	12%	8.30	1.394,76
MV Distribution part	13%	8.98	1.077,26
LV Distribution part	45%	31.11	641.49
T o t a l	100%	69.13	

Note : To obtain Facilities cost Rp/KW/Year.

Rp./kWh x annuity factor
0,146824 (12%, 15 years)

Facilities (fixed assets) have a life-time $\pm$ 15 Year.

FACILITIES COST
(JAVA)

Table : 16
Shadow P r i c e

in constant Rp 10^9

Supply Voltage	Generation (1)		Transmission EHV/HV (2)		Primary Distr. MV (3)		Secondary Distr. LV (4)		Total (5)	
	Per kW	Per kW / year	Per kW	Per kW/ year	Per kW	Per kW/ year	Per kW	Per kW/ year	Per kW	Per kW/ year
a.HV(70/150kV) for peak Saguling	13.642	2.003	5.945	872					19.587	2.875
b.MV(6/12/20kV) for peak/ Saguling	14.860	2.182	6.475	950	8.342	1.224			29.677	4.356
C. Base LV(120 V/380V) for peak/ Saguling	21.228	3.116	9.251	1.357	11.918	1.750	48.505	71.21	90.902	13.344

Note : 1. To convert Rp./kW to Rp./kW/Year,multiply by the annuity factor 0,146824 (12%, 15 year)

2. Not shadow Price = Shadow Price.

Table 17a

ENERGY GENERATION COST

A). Gas Turbine (peaking)

Fuel Use = 0,456 litres per kWh

Lube Oil Use = $3,6 \times 10^6$ l/ kWh @ Rp.130.92/l negligible cost

1. Shadow Price (international price for high speed diesel-HSD) 1/

Fuel price US $ 15.5 per barrel

$$\frac{15.5\ (\$) \times 625\ (Rp./\$)}{159\ (lit/barrel)} = Rp.60.93 \text{ per litre (border price)}$$

Fuel Cost = Rp..60.93 x 0.456 = Rp. 27.78 / kWh

2. Not Shadow Price (domestic price)

Fuel price = Rp.43,03 / l HSD for Gas Turbine (local price)

Fuel Cost = Rp.43 x 0.456 = Rp. 19.62 per kWh

B). Steam (Base load).

Fuel Use = 0,303 l/kWh

1. Sh. Pr. (international price for medium fuel oil/Bunker C) 1/

Fuel price = US $12 per barrel

$$\text{Fuel Cost} = \frac{12 \times 625}{159} \times 0.303 = Rp.\ 14.29 \text{ per kWH}$$

2. Not Sh.Pr.

Fuel Cost = 30,93 (Rp./l) x 0.303 (l/kWh) = Rp.9,37 / kWh.

Note : dom.pr = domestic price
sh.Pr. = shadow price.

Based on : 1 US$ = Rp.625.-

For not shadow price (HSD fuel for peak Gen (Gas T.) + 70% of existing price =Rp.43,03/l
(Banker "C",for base Gen.(steam T)+ 40% of existing price=Rp.30,93/l

1/ Most recent ex-Singapore prices (Feb. 1979). However, these values may have to be revised if international oil prices increase in the future.

ENERGY/FUEL COST

Table 17b:

	Based on G.T. Using H S D.	Based on Steam Plant Using Bunker C
A. Shadow Priced	Rp.27,78 / kwh (output from Generator)	Rp. 14.29 / kwh (output from Generator).
a). HV Consumers	Station use = 2 % Transmission Losses EHV/HV = 4,5 x 1,5 Total = 8,75 ≈ 8,8 % $\frac{27.78}{0,912}$ = Rp.30.46 / kwh	Station use = 4,5 % Transmission Losses EVH/HV= 4,5 x 0,8 Total = 8,1 % $\frac{14.29}{0,919}$ = Rp. 15.55 / kwh
b). MV Consumers	MW Losses = 6 % x 1,5 = 9 % $\frac{30.46}{0,91}$ = Rp.33.47 / kwh	MW Losses = 6 % x 0,8 = 4,8 % $\frac{15.55}{0.952}$ = Rp.16.33 /kwh
c). LV Consumers	LV Losses = 20% x 1,5 = 30 % $\frac{33.47}{0,7}$ = Rp.47.82 / kwh	LV Losses = 20% x 0,8 = 16 % $\frac{16.33}{0,84}$ = Rp 19.44 / kwh
B). Not Shadow Price	Rp.19,62 / kwh (output from Generator)	Rp.9,37 / kwh (output from Generator)
a). HV Consumers	$\frac{19,62}{0.912}$ = Rp. 21.51 / kwh	$\frac{9.37}{0.919}$ = Rp.10.20 / kwh
b). MV Consumers	$\frac{21.51}{0.91}$ = Rp. 23.64 / kwh	$\frac{10.20}{0,952}$ = Rp.10.71 / kwh
c). LV Consumers	$\frac{23.64}{0,7}$ = Rp.33.77 / kwh	$\frac{10.71}{0,84}$ = Rp. 12.75 / kwh

Note : - For peak load : the losses = 1,5 x average losses
- For base load : the losses = 0,8 x average losses
- 0,912 = 100 % - 8,8 % = and so on for loss factors.

JAVA BASIC L R M C (LONG RUN MARGINAL COST)

TABLE : 20

A. SHADOW PRICED

SUPPLY VOLTAGE	KW COST (Rp.kW/YEAR)					FUEL COST Rp./kWh 1/					
						(A) Barrel		(B) Barrel			
	Capacity Cost	O & M	G & Adm	Facilities	Total kW Cost	BASE	PEAK	BASE	PEAK		
HV Consumers Peak	66.070	11.302	2.412	2.875	82.659	15.55	30.46	12.96	25.54		
MV Consumers Peak	97.072	17.125	3.652	4.356	122.205	16.33	33.47	13.61	28.06		
LV Consumers Peak	278.201	52.448	11.185	13.344	355.178	19.44	47.82	16.20	40.08		
B. NOT SHADOW PRICED											
HV Consumer Peak	68.016	11.302	2.412	2.875	85.605	10.20	21.51				
MV Consumer Peak	100.600	17.125	3.652	4.356	125.733	10.71	23.64				
LV Consumer Peak	288.010	52.448	11.185	13.344	36.4987	12.75	33.77				

1/ fuel prices in US $ per barrel are:

(A) Base (Fuel oil) = 12
(B) Peak (HSD) = 15.5

(A) Base (Fuel Oil) = 10
(B) Peak (HSD) = 13

TABLE : 21

EQUIVALENT BASIC L R M C (LONG RUN MARGINAL COST) - JAVA

A. SHADOW PRICED

SUPPLY VOLTAGE	CAPACITY COST (Rp./kW/year	EQUIVALENT ENERGY COST WITH OWN LOAD FACTOR (Rp/kWh) 1/							FUEL COST (Rp/kWh) (A)			TOTAL COST WITH OWN LOAD FACTOR (Rp./kWh) 4/						
		0.3 2/	0.4	0.5	0.6	0.7	0.8	0.9	Base	Peak	Aver	0.3	0.4	0.5	0.6	0.7	0.8	0.9
HV Consumers Peak	82.659	28.31	21.23	16.98	14.15	12.13	10.61	9.43	15.55	30.40	19.28				33.43	31.41	29.89	28.71
MV Consumers Peak	122.205	34.87	26.15	20.92	17.43	14.95			16.33	33.47	20.62			41.54	38.05		35.57	
LV Consumers Peak	355.178	94.6	70.95	56.76	47.3	40.54			19.44	47.82	33.63	128.23	104.58	90.39	80.93			

B. NOT SHADOW PRICED

HV Consumers Peak	85.605	29.32	21.98	17.59	14.66	12.56												
MV Consumers Peak	125.733	35.88	26.91	21.53	17.94	15.38												
LV Consumers Peak	364.987	97.22	72.91	58.33	48.61	41.66												

Note : - Coicidence Factor (cf) : HV=0,9; MV=0,75 and LV=0,7

1/ Equivalent Rp./kWh $= \frac{\text{Rp./kW/year x C.f.}}{8760 \times \text{own load factor}}$

2/ Own load factor=Load factor with respect to own individual peak demand.
For MV Consumers equivalent Rp./kWh decreased by factor 0,5 because MV demand at time of system peak is one half the MV own peak demand (i.e.their peak falls outside system peak),if necessary;e.g., max demand metering.

3/ Average Fuel Cost : HV : 75% Base + 25% Peak
MV : 75% Base + 25% Peak
LV : 50% Base + 50% Peak

4/ These are only approximate total costs per average kWh.

Adjusting Strict LRMC

A power tariff revision for Indonesia was particularly urgent in 1978 because the existing tariff was first introduced in 1973 following a SOFRELEC power pricing study. Because of administrative reasons relating to the regulations governing tariff changes, however, subsequent tariff increases that raised the average price by almost 100% between 1973 and 1978 were implemented by applying a surcharge to the energy price alone. Therefore, the structure of tariffs was badly distorted; in particular, the ratio of kWh to kW charges was far too high. Also, since price increases were introduced in an ad hoc manner, based almost exclusively on financial requirements, the level and structure of tariffs did not reflect the economic costs of supply for the various consumer categories.

Until quite recently, PLN was not in a position to satisfy the rapid growth of demand of the Indonesian power market and, therefore, their policies were not designed to encourage new consumers. For example, payment of the full connection charge was required in advance; for medium and large consumers, this amounted to the substantial figure of Rp 120 per VA. In some cases, even customers who had paid the relevant fees were not connected because of lack of system capacity and administrative bottlenecks. As a result, a rapid increase in captive generation occured, amounting to almost half the total Indonesian power market by 1977. Since 1978 the situation has improved considerably, however, PLN has embarked on a program of balanced system expansion, which includes adding base load generating plant, strengthening transmission interconnection, alleviating distribution bottlenecks, and upgrading existing networks. PLN is also trying to increase their market share

provided to alleviate the high connections cost. This can be done by subsidizing possibly from 50 to 90% of the costs and by lenient payment options, (perhaps extending for several years). PLN is reconsidering details of its connections policy, given its impact on its cash flow and general financial situation.

The tariff study raises several issues. The first and probably the most important is whether or not to continue a uniform national tariff policy. Strong practical considerations would appear to support implementation of a uniform tariff, as a first step in tariff revision. In theory, LRMC of supply should be estimated for each separate island grid and a corresponding geographically differentiated tariff should be devised. LRMC should be based on a least cost expansion program, however, and the Java system investment plan is the only one that may be considered acceptable, while the planning for capacity additions and other data for the other islands are far less reliable. Therefore, only the Java LRMC may be calculated with sufficient confidence at the present time. Furthermore, Java constitutes about 80% of the total Indonesian power market, and will continue to do so during the planning period (1979-80).

Therefore, given that geographically distinct electricity prices would be unacceptable to the government and that tariff reform is urgent, a uniform national tariff based on the Java LRMC alone would constitute a first-step improvement. As system planning, least cost investment policy, and other data on the outer islands, are improved, it may be possible to calculate geographically disaggregate LRMC and introduce these in subsequent tariff revisions.

The Java LRMC should be refined by improving the data relating to the load forecast, demand characteristics, losses, investments, and operating costs. Similarly, the LRMC for the other island grids should be computed, after building up the data base. Since the load outside of Java is only about 20% of the total load for Indonesia, an approximate estimate of transmission and distribution costs may be made as an average for all the islands (outside Java). Generation costs would have to be determined on the basis of capacity and fuel costs of the specific plant types used for each of these smaller grids. O&M, A&G, and other costs would also have to be estimated from improved PLN data. In subsequent tariff calculations it may also be necessary to examine specifically rural electricity supply costs and pricing policy. This is not a problem now because the number of these customers is negligible.

Typical Strict LRMC Pricing Structure

Given a 4 hour peak period, from 1745 to 2145 hours (see Figure 6.8), a possible strict LRMC tariff structure would be the following:

1. HV Consumers

   a. With time-of-day metering:

      Assume coincidence factor of 0.9.

      Peak charges: capacity cost $= \frac{82.659}{12} \times 0.9$ (CF)

      $=$ Rp. 6199/kw/month

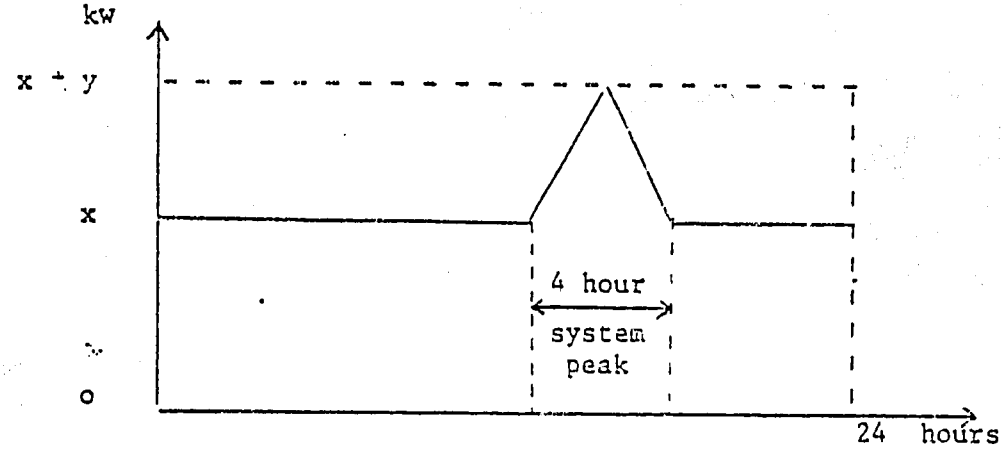
      energy cost $=$ Rp. 30.46/kwh

      Off-peak charges: energy cost $=$ Rp. 15.55/kwh

   b. With maximum demand metering:

      HV consumers' peak is assumed to fall within the system peak period. Therefore, same charges as those in 1(a) apply.

Figure 6.8. Daily Load Duration Curve for Low Voltage Consumers.



Transition to Tariff

Generally, the average level of tariffs is constrainted. An average price of approximately Rp. 40 a kWh is assumed necessary to ensure adequate values for projected financial performance indiators and therefore, the tariff structure had to have an average electricity price near this value. Other tariff constraints that are more consumer specific will be discussed according to the appropriate tariff category.

The proposed new tariff is given in table 6-23. The columns in the table may be described as follows:

1. Originial (1973) consumer categories

2. New consumer categories that do not always correspond exactly to the old ones. The main criteria for structuring the new tariff are type of electricity use, voltage level, and connected kva. Therefore, the categories A, B, C, D and F represent residential, special (for example mosques), commercial, industrial, and temporary consumers, respectively. The letters R, M, and T indicate low, medium and high voltage supply. The category Khusus represents consumers who obtain specially negotiated contracts.

3. The range of connected volt-amps

4. Total number of consumers (1977/78)

5. Total connected VA (1977/78)

6. Total kWh consumption monthly

7. VA per customer

8. kWh per consumer monthly

9. Tariff: capacity charge per month per kva (The charge per peak kw is given in parentheses for MV and HV consumers with adequate metering--the equivalent charge per kva is given only to estimate revenue).

10. Tariff: energy charge per kWh divided into peak and off-peak components for MV and HV consumers.

TABLE 6-23

(1) 1971	(2) Code	(3) Class	(4) No. of Consumers	(5) Connected (VA)	(6) kWh Consumed	(7) VA/Cons.	(8) kWh/Cons.	Tariff (9) per kVA (or peak kW)	Tariff (10) per kWh (p-peak (op-off peak)	(11) Revenue	(12) Rp/kWh Av. Rate	(13) Comments
A1	A1/R	75 - 220 VA	595.703	83.465.840	41.186.439	140	69	--	--	3112	27.0	Flat rate Rp. 1850/month
[illegible]	[illegible]	[illegible] VA	[illegible]	1.[illegible].937.918	69.511.926	715	121	3.200	20	2699	38.6	
B1	B1/R	3.6 kVA 10	21.470	129.551.163	15.076.317	6.034	732	3.200	20	716	47.5	
B2	B2/R	135 kVA 630	4.426	82.038.951	13.713.944	18.535	3.098	6.400	20	799	58.3	
B (Ext)	B2/N	kVA 100	257	103.036.500	13.674.583	400.833	53.988	5.330 (6400)	p: 25.3 op: 16	808	58.3	25%P Rp. 10.2/kWh 75%OP (av.)
D - A2	D1/R	25 VA 630	1.195 15.055	23.168.163 10.399.370	8.514.174 6.276.552	3.905	909	-	31.3	463	31.5	
B (Social)	B1/N	kVA 100	55	21.690.000	2.777.959	394.364	50.508	3.200 (8000)	p: 14.7 op: 6.7	95	34.3	33%P Rp. 9.3/kWh 67%OP (av)
C2	B2/R	250 VA 630kVA	19.340	93.658.317	18.907.764	4.841	977	4.670	16	740	39.1	
C (Ext)	D2/N	kVA 100	276	89.844.500	10.907.556	397.582	48.264	3.330 (8100)	p: 16 op: 10	416	38.1	20%P Rp. 11.2/kWh 80%OP (av.)
D2	D1/R	250 VA 1300	82.206	54.648.386	8.984.952	665	109	--	18.7	430	47.9	
B2	C2/R	1331 VA 630kVA	34.720	198.600.212	23.087.212	5.720	665	4.800	18.7	1384	60.0	
B (Ext)	C2/N	kVA 100	260	106.447.250	15.242.531	409.412	58.625	3.330	p: 16 op: 8	517	34.0	33%P Rp. 10.6/kWh 67%OP (av.)
C1	D1/R	5.6 kVA 630	5.770	46.142.230	9.309.224	25.128	1.613	2.400	p: 26.7 op: 13.3	500	53.7	25%P Rp. 16.9/kWh 75%OP (av.)
E (Ind)	D2/N	100 kVA 1000	532	232.709.667	40.342.660	437.424	75.832	3.200 (8000)	p: 16.7 op: 10	1218	27.5	25%P Rp. 11.7/kWh 75%OP (av.)
E (Ind)	D1/T	kVA 5001	3	36.673.333	7.812.728	12.224.444	2.604.242	3.070 (5070)	10.7	196	25.1	
F	F		-------	----------	1.314.140	----	----	-----	75	98	75	
Khusus	Khusus		66	7.089.200	2.215.236	----	----	-----	--	----	--	
Jumlah					307.153.484					12191	39.7	

Note: MV and HV consumers who have low power factor (pif) should be penalized by a % increase in the tariff for every % point their pif falls below a initial value (e.g. 0.85).

11. Expected revenue on the basis of 1977/78 consumption and new tariff

12. Average price per kWh

13. Comments

In general, tariff levels are below strict LEMC to keep within the bounds for the overall average price per kWh. The residential and low voltage categories receive the greatest reductions as a fraction of strict LRMC.

A1/R: Low Income Residential/LV. Government policy requires this category to be heavily subsidized. There is no kWh metering; only a load limiter.

Suppose the average charge to the consumer is Rp.x for each connection montly; but average consumer cost per kWh for month is 70.

Average price per kWh = Rp.x/70 per kWh.

Full LRMC tariff = Rp. 105.3/kWh.

Full equivalent charge is given by:

$$105.3 = x/70$$

$$x = \text{Rp. } 7{,}371/\text{connection/month}$$

Assume that A1/R consumer's income is 0.25 times the national average. Therefore, reduce x by a factor 0.25 to obtain subsidized "social" tariff (see Chapter 4 for theory).

Subsidized tariff is approximately Rp. 1,850 per connection monthly.

A2/R, A3/R, A4/R: Middle to High Income Residential/LV. In these categories, kW metering exists and a separate capacity charge is levied as a flat tariff on each connection monthly. Also, there is a separate energy charge. The total price per kWh (column 13) lies between the A1/R tariff and full LRMC,

and increases with increasing ability to pay. That is, a departure from strict LRMC decreases as income level increases.

To compare the tariff with strict, LRMC, assume that the utilization factor = $\frac{\text{contribution to system peak kw}}{\text{installed kva}} = 0.3$

LRMC Capacity Cost = Rp. 29, 598/kw monthly

= Rp. 8,880/kva monthly

LRMC Average energy cost: F = Rp. 34.4/kWh

A4/M: Very High Income Residential/MV. Assume time-of-day metering exists for measuring peak demand. Both the capacity and energy charges are effectively the full LRMC. Note that the actual tariff of Rp. 8,000/peak kw is assumed to be equivalent to Rp. 5.330/kva to estimate the projected revenue.

B1/R, B1/M, B2/R, B2/R: Special/LV and MV. Tariffs are generally less than strict LRMC, but the deviation is smaller for the MV than for the LV consumers, who are assumed to be less well-off. The large difference between capacity charges per kva and per peak kw for MV consumers is because their own peak occurs during the day, thus making the contribution to the system peak rather small.

C1/R, C2/R, D1/R: Commercial and Industrial/LV. Average tariff levels are comparable with high income residential users.

D2/M, D3/T: Industrial/MV and LV. Upper bound on average tariffs and energy charges will be competitive with auto-generation. Tariffs can be modified given more detailed information on private generation costs.

F, Khusus: Temporary and Special Contracts. Temporary users pay very high kWh rates. Special contracts will be user-specific.

Total average tariff level for all consumers = Rp. 39.7 for every kWh sold which is within the bounds discussed at the beginning of this section.

CASE STUDY II

INTERFUEL SUBSTITUTION ISSUES IN SRI LANKA

I. Introduction

In recent years, decision makers in many countries have realized that energy sector investment planning and pricing should be carried out within the framework of a national energy master plan which determines energy policy, supply-demand management and planning. However, in practice investment planning and pricing are still carried out on an ad hoc and at best partial or sub-sector basis. Thus, for example, planning in the petroleum and electricity sub-sectors has traditionally been carried out independently of each other, and of other energy sub-sectors. As long as energy was cheap such partical approaches were acceptable; with today's rising energy costs and fluctuating relative fuel prices, the importance of analyzing interactions among different energy sub-sectors in the process of optimal resource allocation has become evident.

A framework for integrated national energy planning, particularly in the LDC context, should include important considerations such as: the interrelationship and substitution possibilities between different energy sources, the difference between private and social costs and benefits (e.g., shadow pricing and externalities), the modification of the economic efficiency objectives in investment and pricing policy necessitated by other financial and socio-political considerations, and the coordinated use of policy tools (e.g., pricing-investment,

physical-technical controls, public education-propaganda).[1] Furthermore, given the frequent over-emphasis on commercial fuels in energy sector analysis, the important role of traditional fuels such as firewood should be recognized.[2]

In this paper, we use a case study of Sri Lanka to illustrate energy sub-sector interactions in a developing country. More specifically, the use of woodfuel, kerosene and liquid petroleum gas (LPG) for domestic cooking is analyzed, including the effects of fuel prices, capital costs of different energy conversion devices and associated thermal efficiencies (e.g., open versus closed wood stoves). The importance of using correct shadow prices (which represent economic opportunity costs instead of distorted market prices) to establish the least cost mix of fuels to meet given energy needs is emphasized. The policy implications of this analysis are also discussed (especially for energy pricing) in an environment in which the relative scarcity of different fuels may change dynamically over time.

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[1] See: Mohan Munasinghe, "Power and Energy Pricing and Investment Policy in Developing Countries," Proceedings of the International Association of Energy Economists Annual Meeting, Washington, D.C., June 1979.

[2] See for example, Mohan Munasinghe and Colin J. Warren, "Rural Electrification, Energy Economics and National Policy in Developing Countries," Future Energy Concepts, Conf. Publ. No. 171, Inst. of Electrical Engineers, London, Jan.-Feb. 1979. pp. 414-417. A survey of non-commercial energy uses in LDC's is found in E. Cecelski et al., Household Energy and the Poor in the Third World, Resources for the Future Research Paper, 15, 1979.

The basic 1976 energy balance for Sri Lanka[3/] is summarized in Table 1. About one-third of the gross energy needs are supplied from commercial fuels (excluding re-exports of residual oil) and the rest from traditional fuels, chiefly wood. Petroleum products account for almost 90 percent of commercial fuel use resulting in a heavy import bill for crude oil. The principal focus of this paper is on domestic cooking, which is dominated by woodfuel use, some kerosene and a very small amount of LPG. Although thermal generation of electricity was negligible in 1976, this situation will change substantially in the early 1980's. Therefore, the mix of outputs from Sri Lanka's petroleum refinery and their use in the electricity producing and other sectors are also of crucial importance.

II. ANALYTICAL FRAMEWORK

In the idealized world of perfect competition, the interaction of atomistic profit maximizing producers and atomistic utility maximizing consumers gives rise to a pareto-optimal. In this state, prices reflect the true marginal social costs, scarce resources are efficiently allocated, and for a given income distribution, no one person can be made better off without making someone else worse off.

However, conditions are likely to be far from ideal in the real world. Distortions due to monopoly practices, external

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[3/] 1976 population approximately 14 million and GNP per capita about US$190.

Table I. ENERGY BALANCE FOR SRI LANKA, 1976
(million GigaJoules of gross input value)

	Secondary Electricity	Commercial Use	Railway Transport	Truck Transport	Air Plane Use	Auto Travel	Bus Travel	Rail Travel	Home Lighting	Cooking	Exports	Total Use
Elec. Generation	--	3.35	--	--	--	--	--	--	0.73[a]	--	--	4.08[b]
Total Elec.												
Gasoline	--	--	--	.46	--	4.13	--	--	--	--	.02	4.61
Diesel & Fuels	--	2.63	.53	5.09	--	--	4.39	1.22	--	--	--	13.86
Kerosene	--	1.02	--	--	--	--	--	--	6.62[c]	2.21	--	9.85
Aviation Gasoline	--	--	--	--	.46	--	--	--	--	--	3.26	3.72
Residuals	.36	5.18	--	--	--	--	--	--	--	--	18.86	24.40
LPG Bottled[d]	--	.03	--	--	--	--	--	--	--	.03	--	.06
LPG Piped	--	.05	--	--	--	--	--	--	--	.01	--	.06
TOTAL PETROLEUM	.36	8.91	.53	5.55	.46	4.13	4.39	1.22	6.62	2.25	22.14	56.56
WOOD & WASTES	--	n.a.[e]	--	--	--	--	--	--	--	40-60	--	40-60
GRAND TOTAL												

[a] Includes very small component for cooking.

[b] 98 percent of this total is primary electricity (hydro) and the rest is secondary electricity (thermal). Losses = 12 percent.

[c] 25 percent of domestic use is assumed to be for cooking.

[d] LPG purchased by Colombo Gas Works is used about 50-50 for bottle and piping. For bottles we assume consumption is split equally between household and other users; for piped gas households are assumed to take 20 percent. The leakage factor of the pipeline system, estimated at 65 percent, is ignored here.

[e] It is not known how much tea drying is still done with wood. If one-fourth to one-half were the proportions and we assume a metric ton of wood has a value of 10-14 G.J., the range of consumption might be about 2.0-4.0 G.J.

economies and diseconomies (which are not internalized in the private market), interventions in the market process through taxes, import duties and subsidies, etc., all result in market (or financial) prices for goods and services, which may diverge substantially from their shadow prices or true economic opportunity costs. Moreover, if there are large income disparities, the passive acceptance of the existing skewed income distribution, which is implied by the reliance on strict efficiency criteria for determining economic welfare, may be socially and politically unacceptable. Such considerations necessitate the use of appropriate shadow prices instead of market prices. These shadow prices should be used instead of market prices (or private costs) in evaluating alternative programs to determine the least cost mix of fuels to supply given energy needs. In this paper, we use the term efficiency prices to denote shadow prices based on economic opportunity costs that reflect only the efficiency considerations of resource allocation.[4/]

In the context of a general equilibrium model, the shadow price of a given resource represents the change in the value of

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[4/] Income distributional considerations which may be used to derive social weights (applicable to costs and benefits according to income level) are ignored. See for example: L. Squire and H. Van der Tak, Economic Analysis of Projects, Johns Hopkins Baltimore (1975); I. M. D. Little and J. A. Mirrless, Project Appraisal and Planning for Developing Countries, Basic Books, New York (1974); P. Dasgupta, A. Sen and S. Marglin, Guidelines for Project Evaluation (UNIDO), United Nations, New York (1972).

the national objective function such as aggregate consumption due to a marginal change in the availability of that resource, subject to a set of distorting constraints.[5/] However, a general equilibrium model sufficiently detailed to be of practical use can rarely be realized, especially in the LDC's because of analytical difficulties, lack of data, and the time and manpower required to build and use it. Therefore, we are forced to use a partial equilibrium approach to examine the market for each energy sub-sector. Linkages with other sectors of the economy and between energy sub-sectors have to be selectively taken care of by appropriate shadow prices, e.g., shadow wage rate, opportunity cost of capital, shadow prices for fuels, and so on.[6/]

In summary, what is meant by integrated energy pricing policy in the economic sense is not a general equilibrium analysis; instead, interactions of the energy sector with other parts of economy, as well as interactions between competing

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[5/] See for example: P. Dasgupta and J. Stiglitz, "Benefit-Cost Analysis and Trade Policies," J. Pol. Econ., Vol. 82, Jan.-Feb. 1974, pp. 1-33; and Peter Warr, "On the Shadow Pricing of Traded Commodities," J. Pol. Econ., Vol. 85, 1977, pp. 865-872.

[6/] The partial equilibrium method has been criticized, on the basis of non-marginality, for its lack of simultaneity, and because of the judgmental element involved in choosing which linkages are to be analyzed and which are to be neglected, when the impact of some disturbance is to be evaluated. However, in principle, these objections can be met by using an iterative process of successive (convergent) approximations, and by considering a sufficient number of linkages, so that the partial equilibrium shadow prices closely approximate the corresponding general equilibrium values.

energy sub-sectors are handled by examining selected linkages and using appropriate shadow prices or opportunity costs as shown in Figure 1. In practice, quite useful results can be obtained from even simple models and considerations as shown below.

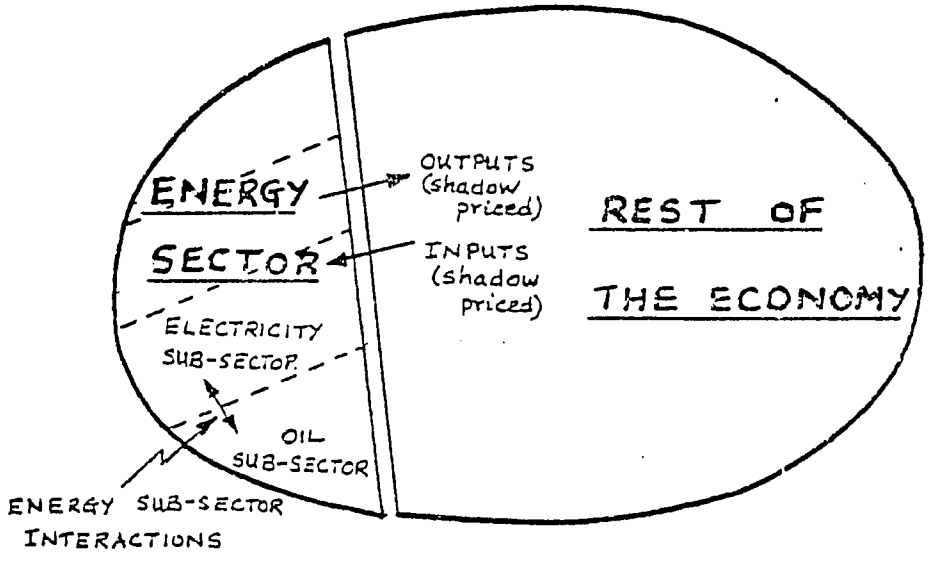

Figure 1. Partial Equilibrium Framework

The demand for energy products is best considered as the demand for the useful service energy provides, in the spirit of

Kelvin Lancaster's new consumer theory.[7/] Thus, for example, households demand energy to cook their meals; they produce the requisite heat by combining capital equipment, fuel, and some labor. The total cost of producing the energy output will depend upon technical parameters such as the efficiency of conversion, and energy input value of fuel; and upon economic parameters such as initial capital charges, fuel costs, and labor costs. To produce cooking heat, one may use a number of different modes and fuel combinations; wood with open and closed stoves, coal, charcoal, kerosene in wick or pressure stoves, LPG, piped gas, and electricity. Since each of these methods will face varying values of the technical and economic parameters noted, the overall costs may vary.

In an equilibrium disregarding personal predilections for one or the other type of cooking method, the private marginal cost of cooking heat will equate across these different methods. In practice, this will not happen for two principal reasons. First, different cookings methods have other characteristics besides technical efficiency and economic cost, e.g., charcoal is traditionally shunned in favor of wood; kerosene is messy and has an unpleasant smell; LPG is considered dangerous, and so on. Secondly, the imperfections of the capital markets--particularly for the small amounts of cooking equipment involved--means that at a given time the capital unit owned

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[7/] Kelvin Lancaster, "A New Approach to Consumer Theory," J. Pol. Econ., Vol. 74, 1966, pp. 135-145.

cannot be sold for its economic value, and the switch over to the lower marginal-cost method will only occur with some time lag. Furthermore, even if private marginal costs are equated, this need not be the case for marginal efficiency costs. A case in point may be fuel wood in Sri Lanka, which some forestry experts feel bears a high social cost because the forest cover of the country is endangered by the cutting of wood for fuel. If indeed this is the case, then the private cost of wood understates its economic opportunity cost, and a private market equilibrium of cooking modes wherein the private marginal cost of cooking with wood equals the private marginal costs using using other means, is socially undesirable for it means that the marginal efficiency cost of wood cooking is likely to be higher than with other methods, unless other fuels are also heavily subsidized (e.g., kerosene).

III. PRIVATE MARGINAL COSTS OF COOKING IN COLOMBO AREA

In what follows, we provide an illustration of this approach applied to the case of cooking fuels in urban areas of Sri Lanka, Colombo in particular. Technical and economic parameters for this are not well established or easy to come by,[8/] therefore, the estimates are indicative at best and must be taken with a large margin of error. However, given the critical

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[8/] In particular, the literature gives values of wood's energy content that vary from as little as 10 G.J./metricton to 18 G.J./metricton. Estimates of the energy content are given in Cedkki op. cit., Brookhaven National Laboratory, Energy Needs, Uses and Resources in Developing Countries, BNL50784, 1978, and in Earl, D.E., Forest Energy and Economic Development, Oxford, 1975. Also as noted in Sec. IV, even private market prices of wood are not well known in Sri Lanka.

situation of rising petroleum prices, potential deforestation and the mid-term exhaustion of major hydro sites, it is necessary to focus on the allocative efficiency of alternative energy forms by analysis of the type described. What we present here can be elaborated with more precision for the parameter values, but even with such rough approximations, the calculations can indicate general policy directions that are likely to be useful.

We focus upon urban areas because for the immediate future the choices available there are substantial and extending these same choices to rural areas would involve considerable cost of networks such as LPG and electricity. Furthermore, the low incomes in rural areas would preclude high-capital-cost options unless substantial subsidy and/or credit facilities were to be provided by the government. Our calculations are limited to five options: wood in open fires and in closed stoves, kerosene in wick-type stoves and in pressure-type stoves, and LPG. For this last, a range of values is given for lack of precise technical parameters. We do not consider charcoal because of the apparent traditional resistance to it, and we exclude piped gas and electricity because they are more limited as options to upper-income households.

Marginal cost calculations are usually done relative to some natural quantitative unit, which for the case of energy may be a kilowat hour, or a BTU or a GJ. In this instance, however, we shall compute the marginal cost as the annual cost of providing cooking heat for an average family of six people.

The family or household is the natural purchasing unit for this product, and we assume it does not decide to cook less or more, but rather it decides to switch from one mode to another. With the exception of open fires, the sunk-cost aspect of capital-equipment means the decision is decidedly long term, and therefore the marginal-cost perspective of the decision maker is likely to be with respect to the total cost for a fixed period of time. In estimating these total costs, we exclude any labor involved for two reasons. First, the labor used in generating cooking heat as such--distinct from the labor used in the culinary process itself--is insignificant except in the case of wood. Second, even with wood the labor cost is very low because of the low shadow price of labor; this is even more true where the labor is done by members of the family for whom, and at times when, alternative opportunities are non-existent. The amount of useful energy output for a year's cooking may be estimated at 5.42 G.J.[9/] Thus, the annual marginal cost as defined will be given by:

$$MCA_i = \frac{5.42/e_i}{EV_i} \cdot P_i + rK_i$$

where e_i is the energy efficiency of the mode i, EV_i is the energy input content in G.J. per unit of fuel type i, P_i is the price of fuel i, r is the annual capital charge, and K_i is the cost of the capital stock required in mode i.

[9/] Based on estimates of firewood used by an average family of six in the Consumer Finances Surveys (1953, 1963, 1973), and an energy content of 14G.J./metricton--the mid-point of the range noted in Footnote 8.

Approximate capital costs (K_i) for the various modes are shown in Table II; they range from zero for an open fire (a few stones) to 700 RS for a simple one-burner LPG stove plus the cylinder. For the kerosene and LPG options, the most rudimentary one-burner commercial stoves are taken as the basis for the computations. Larger two-burner models of better quality can be as much as 600-700 RS for kerosene, and over 1,000 RS for LPG. On the other hand, rudimentary handcrafted equipment can probably be made for much lower costs, perhaps as low as $7.00.[10/]

For the case of LPG, marginal efficiency costs must include the potential capital costs incurred by the Colombo Gas Works to permit expansion of the use of LPG, because at present the facilities for storage and distribution are fully used up. A feasibility study of such an expansion was done for the Colombo Gas Works recently and from this one can attribute such capital costs at 25 million RS for 40,000 households, or 625 RS per household or family. Annual capital-use cost would be given by the appropriate capital charge "r" (rate of discount in cost-benefit approach), which we show as taking two values of .15 and .20,[11/] resulting in private capital charges annually of 15-20 RS for wood stoves, 30-40 RS for kerosene stoves with wicks, 45-60 for kerosene pressure stoves, and 105-140 for LPG

[10/] At the Gannaruwe biogas site in Sri Lanka, a hand-fashioned gas burner was said to cost less than 100 RS.

[11/] We use relatively higher "r" values to bias the calculations in favor of firewood, thereby fortifying the conclusion that LPG which has a high capital cost, may be the most economically efficient mode.

equipment. Efficiency costs (at the given r values) would be the same except for LPG, where it rises to 200-265 RS. Clearly, the capital cost element is strongly unfavorable in the case of LPG and highly favorable in the case of wood. The various modes ranked in ascending order of capital cost are: open fire, wood stoves, kerosene wick stoves, kerosene pressure stoves, and LPG stoves.

Table II. APPROXIMATE CAPITAL COSTS IN RS OF COOKING EQUIPMENT PER FAMILY

Mode	Total Capital Cost	Annual Cost at r=	
		.15	.20
Open Fire	0	0	0
Closed Stove	100	15	20
One Burner Kerosene Stove			
wick	200	30	40
pressure	300	45	60
One Burner LPG Stove	250		
Cylinder	450		
Private Total (LPG)	700	105	140
Additional LPG Social Cost*	625	95	125
Total LPG Social Cost	1,325	200	265

*Based on proposed Gas Works project of expanded delivery to 40,000 houses.

Source: Estimates from author's observation, information provided by Colombo Gas Works and other ubpublished Sri Lanka data.

The fuel cost component, at 1979 private market prices, changes this ordering considerably as can be seen in Table III, under the "Fuel Cost" column. Kerosene has the lowest fuel cost, LPG is next,[12/] while wood is most expensive regardless of the type of converter used. The very low capital charges for wood cooking are not enough to outweigh the high fuel cost; and the overall marginal cost (last two columns of Table III) for open fires is decidedly higher than for the other modes, which with a closed stove it is about comparable to LPG if the latter's "high requirements" are taken, but more expensive than LPG if the "low" value is considered for LPG. Both wood and LPG have marginal costs much higher than kerosene stoves of either type. Even if the capital costs of kerosene stoves were in fact substantially greater--say 500 RS instead of 200-300 RS--this conclusion would still hold, as the overall marginal cost for kerosene would be in the range 315-380 RS, still below all the other options. For the private decision maker--the household or family unit--it seems clear that in terms of cost, kerosene is the best option at 1979 prices. Fragmentary and casual evidence on usage patterns suggests that a very large number of urban households, perhaps 60 percent or even more, still continue to use wood, while only about 35 percent use kerosene, the rest using gas (mostly bottled LPG, and some piped) and electricity. Why is there such a very high use of wood given its costs are nearly twice that of kerosene,

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[12/] Lack of data on LPG precluded comparable computations of efficiency and energy content. We took istead an estimate of annual usage by a "customer" as shown in a Colombo Gas Works feasibility study. The study gave two values (100 and 150 KG) which we use as a low and high.

Table III. PRIVATE MARGINAL COST OF COOKING HEAT IN URBAN AREAS, PER FAMILY/A
(required output = 5.421 G.J.)

Mode	Efficiency	Input in GJ	Input Value in GJ	Units Required	Unit Price (Rs)	Fuel Cost (Rs)	Capital Cost (2r) r=.15 (Rs)	Capital Cost (2r) .20 (Rs)	Overall Cost at Market Prices r=.15 (Rs)	Overall Cost at Market Prices .20 (Rs)
WOOD										
Open Fire	.15	36.13	15/Ton	2.4 MT	264/MT	635 Rs	0	0	635	635
Closed Stove	.20	27.1	15/Ton	1.8 MT	264/MT	475	15	20	490	495
KEROSENE										
Wick Stove	.43	12.6	.1569/IG	80.3 IG	2.48/IG	280	30	40	310	320
Pressure Stove	.51	10.6	.1569/IG	67.6 IG	3.48/IG	240	45	60	285	300
LPG										
High Requirement	--	--	--	150 kg	2.6/kg	390	105	140	495	530
Low Requirement	--	--	--	100 kg	2.6/kg	260	105	140	365	400

Source: Author's estimates as described in text and earlier tables.

and why such a low use of LPG given it is only somewhat higher than kerosene, but far less costly than wood? Various explanations can be put forward. The high price of wood is recent, doubling in the last two years, while kerosene prices have been steady at 3.48 RS in that period. Therefore, in 1977, the marginal costs were about equal, and since adjustment involves time lags of recognition, and capital investment needs, the process may be only beginning. Further, we have noted that traditional preferences favor wood for its "taste" qualities, and in fact the equilibrium is perhaps one in which wood does have a somewhat higher cost. As to LPG, it is even less well known to low-income people than kerosene (the latter having been used for lighting for sometime), may be considered risky, and it may be considered inconvenient given the refilling--say 50 RS per annual for taxi fares to take bottles to a depot--and our figures may be a slight underestimate. This is not likely to be enough to make its cost approach that of wood. Further, it may be argued that only owning one bottle is inconvenient as refilling must be done at inconvenient times, or that to avoid this one must invest in an additional bottle. At a cost of 450 RS per bottle, this means an additional 75-100 RS per annum in costs; these two factors may therefore add a perceived cost of 100-150 RS to LPG use, making it comparable to wood at current prices. Inasmuch as it is arguable whether these cost items are essential, we have not included them in the total, but it is important to recognize this "inconvenience" cost associated with LPG in trying to understand the apparent

differences in marginal costs that exist. Such factors may result in a market equilibrium wherein observed marginal costs are not equal.

IV. MARGINAL EFFICIENCY COSTS OF COOKING IN COLOMBO AREA

In the preceding discussion, comparative costs of alternative cooking methods were based upon current market prices. As such, the marginal costs computed are appropriate only to analyze and understand how private individuals made their choices of cooking methods. This is a critical aspect of any actions taken to implement policy goals for after all policies are intended to induce certain behavior by individuals. In addition to this, however, policy goals must be decided upon, and in this the objective of social optimization is pertinent. Therefore, the cost comparison of alternative methods must also be done using social opportunity costs, or shadow prices. Wood may be in short supply and its cutting may be causing deforestation; the market price of wood of 264 RS /metricton may therefore understate the economic opportunity cost. Kerosene prices at 3.48 RS/gallon undoubtedly understates the opportunity cost, being kept low by the government subsidy policy. LPG which is in excess supply in Sri Lanka, on the other hand, a near-zero opportunity cost at the refinery rather than the value of 1.4 RS/kg currently paid by the Colombo Gas Works.

Although it is not possible to specify with precision the opportunity costs for these three fuels, particularly for firewood, it is reasonable to approximate these in ranges to

permit analysis of the relative marginal costs in question. Since the dicergence of private and efficiency costs of firewood is not well established, we calculate first the efficiency costs assuming the market price of wood is a correct reflection of marginal efficiency cost, as shown in Case I of Table IV. Kerosene's opportunity cost is reasonably firmly established on the import-price basis at about 9 RS/gallon. LPG costs are less clear, though they are certainly below the 2.6 RS/kg market price currently charged consumers. Operating costs for the proposed expansion of the Gas Works sales are about 1.3 million RS for 5.5 million kilograms of LPG, or about .25 RS/kg. If we add to this the ex-refinery efficiency cost estimated to be about half the current price of 1.4 RS/kg, this implies a total efficiency cost of about 1 RS/kg. To bias our estimate against LPG, and to reflect the fact that any substantial increase in use of LPG would change the excess supply situation of the Ceylon Petroleum Corporation (CPC) refinery,[13/] we take 2 RS/kg as the shadow value of LPG in efficiency prices. In addition to the fuel cost of LPG, investments beyond the private ones of stove and cylinder must be undertaken. This consists primarily of additional storage tanks, land and some distribution equipment, and is estimated by the aforementioned feasibility study as about 25 million RS for 40,000 customers, or 625 RS per household. The resulting total annual capital charges are shown in Table II as 200-265 RS.

[13/] Sri Lanka's refinery is operated to meet needs of high demand middle distillates, resulting in surpluses of certain other products; more than half of the potential LPG is therefore flared off.

Table IV. COMPARATIVE COOKING COSTS PER FAMILY/ANNUM AT SOCIAL OPPORTUNITY COST[a]

Mode	Capital Cost r=.15	Capital Cost .20	Fuel Costs Price	Fuel Costs Total	Annual Social Cost r=.15	Annual Social Cost r=.20	Fuel Costs Price	Fuel Costs Total	Annual Social Cost	Annual Social Cost
WOOD (MT)										
Open Fire	0	0	264	635	635	635	396	950	950	950
Closed Stove	15	20	264	475	490	495	396	712	727	732
KEROSENE (IG)										
Wick	.30	40	9.0	723	753	763	9.0	723	753	763
Pressure	45	60	9.0	608	653	668	9.0	608	653	668
LPG (kg)										
High	200[b] (105)	265 (140)	2.0	300 (405)	500 (440)	565	2.0	300	500 (405)	565 (440)
Low	200 (105)	265 (140)	2.0	200 (305)	400 (340)	465	2.0	200	400 (305)	465 (340)

[a]Economic opportunity cost is assumed to be 9Rs/IG for kerosene and 2.0Rs/kg for LPG.

[b]Values from Table II. The values in brackets are the private capital costs. For purposes of private, the bracket values in LPG are to be compared with the costs for other fuels.

Source: Author's estimates as described in text and earlier tables.

Under these conditions, the Case I results show kerosene to be the least economic alternative, with a cost ranging from at least 650 RS to 760 RS. This exceeds the open-fire cost of 635. The most economic method is less clearly identifiable, because of the uncertainty as to the amount of LPG required. If the low assumption is correct, LPG is doubtless the least-cost method; if the high value is taken, the use of a closed stove may be most economical. In any event, there is no question that the market prices of kerosene greatly understate its relative cost and probably results in an inefficient allocation of resources, overutilizing kerosene. The incorrect pricing of fuels may also be overstating the cost of LPG usage, which again leads to some inefficiency--albiet less significant than for kerosene--with less LPG being used than a social optimum might dictate.

Note that if the assumed efficiency costs of Case I were to be reflected in market prices, the private costs would favor LPG even more strongly (see bracketed values for LPG), because some of the investment costs for LPG are not private ones.

The cost advantage of LPG would become quite definite if the opportunity cost of firewood were to exceed its market price. Case II in Table IV shows the values for an efficiency price that is 1.5 times the current market price for wood. This is taken to illustrate the point, even though it would suffice to have the efficiency price rise to 1.2 times market price to give LPG a clearer advantage. Were the true cost of wood to be this high, its use as cooking fuel would begin to

exceed kerosene methods, resulting in an overall marginal cost of 537-615 RS, still well below the kerosene costs.

In conclusion, we find that efficiency pricing of kerosene and LPG, while taking market prices for wood, makes kerosene come out as the high-cost method and LPG the probable low-cost option. Higher efficiency costs for wood enhance the cost advantage of LPG, but if the wood price rise is substantial, kerosene may eventually once again be the low cost option, given the severe volume limitations of LPG, and a consequent sharp rise in its marginal costs. This suggests a possible reliance on kerosene as an economical cooking fuel at some future time, with an intermittent period of expanded use for LPG. Refocusing upon kerosene suggests the need to investigate the robustness of the LPG cost. If we consider only the higher-case assumption and assume that stove costs are double (500 instead of 250 RS), while other costs are left the same since they are more solidly founded, we find that the supplies at the costs compiled are quite small in volume relative to the total cooking-fuel market. They apply perhaps to 40-50,000 households, in a market of 200,000 or more.

V. CONCLUSIONS AND POLICY IMPLICATIONS

The calculations presented here are partial ones excluding some cooking methods, and contain a number of uncertanities pertaining to technical energy-value contents and to prices. Nevertheless, they are robust enough to permit some tentative conclusions.

1. LPG, which is essentially disregarded in energy policy discussion in Sri Lanka because of its very small volume, may have a very important role to play in easing the fuels problem in urban areas. Its marginal efficiency costs are probably lower in cooking than those of competing fuels --wood and kerosene--especially so if market prices of wood understate the social opportunity cost. Though this is a small contribution to the problem, so too is the cost of the investment project in the Colombo Gas Works at about 50 million RS, including the costs of bottles for re-sale to customers. More important, there are future possibilities of gas usage beyond this relying upon coal gasification methods, perhaps using imported coal from South Asian areas such as India, Thailand, Indonesia, or even China or East African deposits. Even though this is a long-term possibility, its prospects might fruitfully be investigated very soon, to take advantage of lower priced coal contracts that may be arranged now before the surge of coal demand expected in a decade.

This coal gasification could possibly extend the supplies of urban gas considerably without too sharp a rise in the marginal costs of the present, further justifying an economic refurbishment of the aging pipeline system in Colombo, which at present suffers 65 percent atmospheric losses. The importance of the medium-term future project of bottled, LPG expansion in this context, is to provide an initial demonstration to consumers, in the nature of propaganda and education about the use of gas for domestic cooking. In addition, it will provide some dynamism to the LPG supply enterprise, a

helpful basis for later investment projects such as pipeline revitalization and coal-gasification. The potential contribution of gas would then be far more significant, servicing 60,000-70,000 customers via bottles and 40,000-50,000 with the 172 million revitalized pipeline system. This accounts for about half of the households in Colombo's present population.

2. In the event of a sharp increase in deforestation problems and a consequent high efficiency cost of wood, pressures upon an LPG switch over might lead to rising marginal cost of this product, resulting in a return of kerosene as an economical alternative. Thus, despite the apparent inefficiency of kerosene use now, policy options should be kept open for a flexible refocusing upon its promotion as a way to save upon scarce firewood. This is made particularly more important by the greater potential of kerosene in rural areas, compared to LPG, because the former's distribution costs are lower excluding the need for heavy metal cylinders, plus the existence of a basic rural network for kerosene now used for lighting only.

3. The far greater thermal efficiency of closed stoves (recall we have over-estimated the efficiency of open fires) makes this option potentially important in certain opportunity cost circumstances, for example, further dramatic OPEC price rises. It suggests also that the even more efficient process of charcoaling and use of closed stoves should be investigated as yet another mode of cooking before undertaking any definitive policy directions in this regard.

A number of important conclusions in the context of energy use patterns in developing countries can be drawn from the specific case study. The first and most important one is that user choices among alternative energy sources will not only be determined by the financial costs of each alternative fuel delivered to the point of use and compared on a net heat content basis. Equally, or more important may be the auxillary costs to the user of converting and utilizing each type. These will be made up by the costs of labor, capital and land related to receiving, unloading, storage, handling, ease of control in use and potential riaks, waste material disposal and system maintenance. Reliability of supply and transportation and uniformity of quality will also be important considerations. Habits and the availability and reliability of experienced operators may significantly affect use, particularly in situations in which the potential choice lies between a known, customarily-used energy material and new alternatives of unknown characteristics where resistance to change may be formidable. Lack of knowledge and experience is perhaps one of the most formidable barriers to change in energy use patterns in developing countries. Only if all of these factors are systematically and carefully taken into consideration will it be possible to bring about desirable changes.

Another important issue raised in this paper is that market prices to users frequently do not reflect the true national economic costs of energy use. Appropriate shadow pricing is necessary to determine the difference, if any, and either changes in market prices or regulations affecting alternative choices

should be used to bring about a realistic choice pattern reflecting economic opportunity costs.

For governments, the fact of the rapidly rising relative costs of energy should act as a strong stimulant to evaluate systematically existing and projected future energy use patterns on a disaggregate basis and relate them to existing or potentially available sources of supply; evaluate the economic opportunity costs of use of the latter; and attempt to bring about desirable changes in future energy utilization patterns in all sectors of the economy. Such promotional activities, however, must take full account of the many related technical, economic and social-psychological factors that affect and influence energy uses and fuel choices.

CASE STUDY III

INDUSTRIAL INTER-FUEL SUBSTITUTION ISSUES IN THAILAND

I. INTRODUCTION

The "energy crisis" is one of the most important developments on the world scene today. The rapid rise in energy costs, especially oil prices, has created major dislocations in the economies of even the industrial giants such as the USA and Japan. The oil importing developing countries have suffered more, with balance of payments difficulties, reduced economic growth rates, and generally adverse effects on economic development. Therefore, energy planning (especially in the long-run), and energy supply-demand management require special emphasis. Even relatively modest improvements in these areas would yield substantial economic savings, because of the huge expenditures required to supply energy as well as to convert and use it.

A framework for integrated national energy planning, particularly in the LDC context, should include important considerations such as: the interrelationships and substitution possibilities between different energy sources, the difference between private and social costs and benefits (e.g., shadow pricing and externalities), the modification of the economic efficiency objectives in investment and pricing policy necessitated by other financial and socio-political considerations, and the coordinated use of policy tools (e.g., pricing-investment, physical-technical controls, public education-propaganda).[1] Furthermore, given the frequent over-emphasis on commercial fuels in energy sector analysis, the important role of traditional fuels such as firewood should be recognized.[2]

This paper is a case study of energy use in the tobacco curing industry in Thailand, which illustrates the various elements in energy planning

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[1] See: Mohan Munasinghe, "An Integrated Framework for Energy Pricing in Developing Countries," The Energy Journal, July 1980.

[2] See for example: Mohan Munasinghe and Colin J. Warren, "Rural Electrification, Energy Economics and National Policy in Developing Countries" Future Energy Concepts, Publ. No. 171, Inst. of Electrical Engineers, London, January-Feb. 1979. pp. 414-417.

discussed above. Tobacco production and curing form a relatively small, but nevertheless important part of Thailand's predominantly agricultural economy. Over sixty percent of the output is regularly exported, and the domestic tobacco industry accounts for some 8% of the total value added of Thailand's manufacturing sector. The major importance of tobacco production is in terms of employment. During the growing season some 275,000 people are working in the fields and another 125,000 find seasonal employment in the curing phase of the production cycle.

Thai tobacco is cured in thousands of brick-lined curing sheds. This process is highly energy intensive. Energy costs amount to between 15 and 20% of the gross mark-up of the curing industry, or 10-15% of the product price. Hence, the industry is quite sensitive to changes in energy costs. All kinds of combustible materials have been, or are being used as heat sources. Examples are: rice straw, sawdust, firewood, lignite coal, and fuel and low-speed diesel fuels.

Recently, a rather rapid switch-over has taken place from indigenous fuels such as wood and lignite, to fuel and diesel oils, in spite of rising prices for the latter. This conversion puts added strains on the unfavorable balance of payments of Thailand, because almost all petroleum products have to be imported. However, from the industry's private point-of-view, the switch-over is advantageous because of a complex combination of input costs, unreliability of alternative fuel supplies, and resulting quality control problems. From a national, or public point-of-view, however, lignite coal, available in ample quantities close to the tobacco producing areas, should be the preferred fuel. However, serious quality control problems requiring the upgrading of raw lignite into briquettes have to be overcome first before lignite would be able to replace the now preferred fuels, petroleum products. This paper discusses appropriate energy pricing and investment policies which could have a major effect on fuel choices in the tobacco curing industry.

IIa. THE ENERGY SITUATION IN THAILAND

Thailand's economy is growing rapidly. Between 1970 and 1977 the annual average real rate of growth of GDP was about 6.2%. Energy consumption between 1970 and 1977 was growing at an average annual rate of some 9.2% (see also table 1). Reflecting the rapid growth of the modern sector of the economy energy intensity per unit of GDP increased at high rates. Between 1960 and 1973, it rose at about 8% per year, or some 270% for the thirteen year period. Until 1973 this trend was actually accelerating. The oil price shock of 1973 led to a temporary decline. However, by 1975 the upward trend once again had reasserted itself.

Petroleum and its products provide the dominant form of energy. In 1977 they accounted for 69% of all consumption, followed by 17% for woodfuels, 7% for hydro, 5.8% for bagasse, and 1.6% for coal (see table 1).

National Energy Policy Issues

The most urgent policy issue confronting the government is the country's overwhelming dependence on oil, all of which is imported (21% of total inputs, costing $1.1 billion in 1977). This makes it highly vulnerable to supply interruptions and trade deficits, as happened in 1973, and, more recently, in 1979. These consequences could have a severe effect on economic growth rates. But continued economic growth is needed to absorb the country's rapidly rising labor force and to reduce the substantial economic inequalities that threaten to de-stabilize the country's political structure and cohesiveness. But continued real economic growth depends on the availability and utilization of ever larger quantities of inanimate energy resources, requiring energy/GDP ratios significantly in excess of unity for the time being. For example, some recent projections call for an overall elasticity of about 1.2 for the first half of the decade and a (somewhat optimistic) hoped-for decline to about 0.9 thereafter.

TABLE 1

THAILAND, ESTIMATED ENERGY CONSUMPTION 1970-1977

ITEM	1970	1971	1972	1973	1974	1975	1976	1977
TOTAL	77,122 100%	90,269 100%	100,145 100%	111,131 100%	113,491 100%	119,732 100%	133,851 100%	142,581 100%
Annual Rate of Growth, %	-------	17.1	10.9	11.1	2.1	5.5	11.8	6.5
Petroleum Products	47,088 61.1%	58,909 65.3%	68,534 68.4%	77,427 69.7%	75,460 66.5%	77,995 65.1%	88,073 65.8%	7,843 68.6%
Hydroelectricity	5,210 6.8%	5,976 6.6%	5,596 5.6%	6,067 5.5%	7,754 6,8%	10,571 8.8%	11,281 8.4%	10,235 7.2%
Bagasse	2,699 3.5%	2,597 2.9%	3,083 3.1%	4,170 3.8%	5,565 4.9%	5,880 4.9%	8,372 6.3%	8,303 5.8%
Coal	1,467 1.9%	1,661 1.8%	1,389 1.4%	1,372 1.2%	2,159 1.9%	2,169 1.8%	2,539 1.9%	2,274 1.6%
Paddy Husk	372 0.5%	394 0.4%	324 0.3%	389 0.4%	360 0.3%	437 0.4%	379 0.3%	386 0.3%
Fuelwood and Charcoal[1] (FAO estimate)	20,286 26.3%	20,732 23.0%	21,219 21.2%	21,706 19.5%	22,193 19.6%	22,680 18.9%	23,207 17.3%	23,735 16.6%
Fuelwood and Charcoal[2] (NEA Statistics)	981	982	767	750	575	567	625	577

Sources: National Energy Adm., Oil and Thailand, 1977. Bangkok, 1978. The FAO Fuelwood and charcoal estimates were based on Food and Agricultural Organization, Timber Trends Study, Thailand, Detailed Description of Surveys and Result, Rome, 1972, table A5-2.

1) Based on pro-rated growth rates of FAO 1970 estimate of 50 tons and 1985 projection of 70 million m^3 FAO. op. cit.

2) As published by NEA.

But while total energy use, as well as energy use relative to GDP necessarily will have to increase further to support modernization, mechanization, and industrialization, efforts can be made to shift energy consumption from critical, imported resources, i.e., petroleum, to potential domestic ones, such as natural gas, lignite, hydro, wood, charcoal, crop residues, and possibly, solar. Such a shift is generally not possible for energy uses that are needed to provide motive power. There are, as yet, no technically or economically suitable substitutes available for gasoline, diesel, and jet fuels for powering mobile equipment such as trucks, cars, tractors or airplanes.[1/] Substitution possibilities therefore are largely limited to energy uses that produce heat for activities such as processing, steam production, cooking, drying, etc.

One major, expected shift will result from the development of newly discovered offshore natural gas deposits in the Gulf of Thailand. Another will come from the development of the Mae Moh lignite deposits. Both of these developments will largely affect the future use of fuel oil because all of the lignite,[2/] and over 90% of the natural gas[3/] will be utilized for power production. Other domestic resources such as undeveloped hydropower sites[4/]

1/ In 1977, the transport sector accounted for some 44%, and agriculture for another 11% of total petroleum products consumption.

2/ However, at least one deposit near Li, in northern Thailand, containing some 15 million tons, has heat rates high enough (6,200 Kcal/Kg dry) to be suitable for other uses such as tobacco drying. In recent years, some 100,000 tons of coal were produced annually from this deposit, all by open-pit mining methods. Most of the coal produced here is actually used by the tobacco industry.

3/ Potential industrial or residential natural gas markets outside the greater Bangkok area are far too small to warrant the high costs of pipeline construction.

4/ Except for several large, potential sites along the Mekong and Salawin rivers which cannot be developed at present for political reasons since the rivers form the borders between Thailand, Laos and Burma respectively.

and wood fuels are fairly limited. Localized shortages of wood fuels and charcoal are developing in various regions of the country. In spite of these welcome changes, demands for petroleum products, in physical terms, are still expected to increase at between one to six percent per year between 1980 and 1990,[1/] which is less than the projected real rate of GDP increase of around seven percent per year for the same period. However, high crude oil prices imply that petroleum imports will continue to represent a serious drain on Thailand's foreign exchange resources.

Shadow Pricing Issues

The existence of protective barriers to trade in Thailand indicate that the local currency is overvalued and thus foreign exchange has a scarcity value.

If we use foreign exchange as the numeraire or unit of value, then this implies that on average, domestic market prices must be reduced by the standard conversion factor (SCF) of 0.79[2/], to compare these values with traded goods valued directly in terms of foreign exchange converted at the official exchange rate i.e., for imports and exports measured at border (or international) prices.[3/] For shadow pricing the inputs used in the comparison of fuel costs however,

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[1/] This range brackets several forecasts from official Thai and World Bank sources.

[2/] Based on the most recently available data (1977) - see Committee for Coordination of Investigations of the lower Mekong Basin, Calculation of Conversion Factors For Project Appraisal, Bangkok, Sept. 1977. These shadow prices are based on economic efficiency consideration only, and ignore income distributional considerations.

[3/] This numeraire is based on the Little-Mirrlees, Squire-Vandertak methodology of shadow pricing. For details: see for example L. Squire and H. Vander Tak, Economic Analysis of Projects, John Hopkins Press, Baltimore, 1975. The traditionally used shadow exchange rate (based on a domestic priced numeraire) is equal to the offical exchange rate divided by the SCF.

more specific conversion factors have to be used. Thus, using the same numeraire the 1976/77 conversion factor for unskilled labor in the tobacco growing northern areas was estimated at 0.32, and the lignite conversion factor was 0.52, based on the proportions of labor, capital and transport used to produce and deliver lignite. These factors have been applied here to the market prices of the corresponding items to measure the real economic costs of producing raw lignite coal, and of using unskilled labor, respectively. The international price of diesel was used directly since it is already in border prices.

While shadow prices may be used to evaluate energy decisions from a national perspective, private sector energy use decisions are being made on the basis of market prices, convenience of use, reliability of supply, etc. The same applies to energy users in the public sector unless they are under direct orders to behave otherwise. Given the high real economic costs (or shadow costs) of petroleum imports which often exceed transaction prices, constant vigilance is needed to evaluate any substantial deviation of economic from market prices that may lead to inefficient energy use decisions from a national point of view. Corrective action, through changes in prices, taxes, or regulattions must be taken when this occurs. The case of the Thai tobacco curing industry provides a useful example of such differences in social and private costs.

Energy Pricing

Energy prices for petroleum products, natural gas (presently under development) and electricity are government controlled, the former through regulated prices, the latter because the power campanies are government owned. Only locally traded woodfuels and coal are free from regulation. Thailand, fortunately, has avoided the pitfalls of heavily subsidizing petroleum prices

in the wake of the 1973 OPEC price increases.[1/] However, while prior to 1973 petroleum products were heavily taxed and thereby made a substantial contribution to overall governmental revenues,[2/] most of these excise taxes, except those on gasoline, were either reduced or completely eliminated. Estimates for 1978 indicated that over 85% of all excise tax revenue on petroleum products would come from gasoline only. As a consequence, market prices for products such as low-speed diesel oil or kerosene compare favorably with those of other energy resources except lignite, as can be seen from table 2. Compared to woodfuels for example, lowspeed diesel oil is somewhat less costly on a net heat content basis. Only lignite coal appears to be considerably lower-priced.

TABLE 2
Comparative Energy Prices, Northern Region, Fall 1978

FUEL	LOCAL PRICE, B U.S.$	U.S. / 10^6 kcal
Fuelwood delivered	6.00/m^3	$14.79
Lowspeed diesel	0.13/ltr	14.14
Kerosene	0.14/ltr	15.36
Lignite (from Li) delivered[a]	12.50/ton	3.11

Sources: National Energy Administration of Thailand, and the tobacco Industry.

[a]Assumes a net heat rate of 4,000 kcal per kg of (moist) coal.

The government makes no attempt to shadow-price the imported petroleum products and to adjust market prices accordingly.

III. THE THAI TOBACCO INDUSTRY

The Thai tobacco industry plays a small, but regionally important role in the economy of the country. Tobacco growing is concentrated in the four northernmost provinces where soils and climate provide exceptionally favorable conditions.

1/ Except for a limited period of time following the 1973 upheaval.

2/ Some 8% of total government revenue in 1972.

Flue-cured Thai tobaccos, particularly the Virginia leaves, are famous for their quality. Over sixty percent of total production is regularly exported, mainly to Western Europe, North America, and Japan. Demands have been particularly strong in recent years because Thai tobaccos have the lowest nicotine content in the world. Furthermore, Rhodesia, Thailand's most important competitor, was until recently strongly affected by the trade embargo.

While only about one-third of one percent, or somewhat less than 50,000 hectares of Thailand's agricultural land is devoted to tobacco growing, (see table 3) the impact on national income, employment and export earnings are much higher. During the tobacco growing season,[1/] some 275,000 farmers and farm workers find employment.[2/] To this have to be added some 125,000 workers during the four-months curing season. Most of the tobacco is produced by small-scale farming units of 2 hectares or less.

Tobacco exports, almost all of them consisting of cured tobacco leaves, accounted for some 1.3% of total exports in recent years, while domestic tobacco product manufacturing represented somewhat more than 8% of the total value added of the manufacturing sector.

Overall, then, in terms of value added, employment creation, secondary derived industrial activities and exports, the obacco industry plays a far larger role relative to its use of agricultural land than any other agricultural product. Only the limited availability of suitable soils and appropriate climatic conditions prevent its further rapid expansion.

1/ Planting periods start either between August and October, right after the end of the rainy period on seasonal land, or start in late November on rice paddy land after the end of the rice harvest.

2/ Equal to some 1.9% of the total agricultural labor force. This means that the labor intensity of tobacco is about 5 1/2 times higher than those of all crops combined.

Tobacco Curing

The tobacco harvesting and curing season lasts through most of the winter, from about November to the end of February. Two or three leaves are picked from each plant every five to seven days early in the season and every ten to twelve days later on. The leaves then are brought to the curing stations which consist of rows upon rows of two-story high frame and brick-sided curing barns. The capacity of each of these barns is about four tons of fresh leaves, which reduce to between 300 and 500 kg when cured.

Quality differentials of fresh-picked tobacco leaves are pronounced. This can be seen from the prices paid to farmers which vary from US¢3 (B/0.60) per kg, the legal minimum in 1978, to US¢14 (฿2.70). The average price paid in 1978 amounted to US¢8 (฿1.60).

Each of the barns is equipped with two simple firing boxes which connect to concrete-lined baffles and then to large diameter sheetmetal pipes inside the barns which serve as heat exchangers. The firing boxes can accept a wide range of combustible materials. In recent years by far the most important were firewood, charcoal, lignite and low-speed diesel or fuel oil. Firewood and charcoal come from the surrounding mountain forests. However, available supplies are quite insufficient to supply the needs of the curing industry. The lignite comes from a number of open pit mines to the south of the tobacco growing areas. The most important source of lignite is at Li. Diesel or fuel oil is bought from local wholesalers at the government-controlled price.

The major consideration in flue-curing of tobacco is temperature control.[1/] Ideally, temperatures are not allowed to increase at rates of more than 1 or 2 degrees per hour, and maximum temperatures must be carefully controlled to obtain a high quality product. The type of fuel used for the curing process has a major effect on the ease or difficulty of control. For control purposes,

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[1/] Thai Leave Tobaccos", Thai Export Bulletin, No. 5. Bangkok, 1967, p. 16.

TABLE 3

THE TOBACCO INDUSTRY IN THAILAND. SOME COMPARATIVE STATISTICS

Year	Area Planted Hectares	Area Planted As A Percentage Of Total Agricultural Land	Yield (Dried) KG/HA	Total Production Tons	Total Value Of Tobacco And Tobacco Products Millions U.S. $	Value of Tobacco Products As A % Of Total Value Of MFG Output	Total Value Of Tobacco Exports Million U.S.$	Value of Tobacco Exports As A Percentage Of Total Exports
1974	46,000	0.35	804	37,000	190	8.0	22.3	0.9
1975	47,000	0.34	915	43,000	230	8.8	28.4	1.3
1976	48,000	0.34	833	n.a.	250	8.3	35.0	1.2
1977	47,000	0.34	766	n.a.	300	8.3	46.2	1.3

SOURCES: Bank of Thailand, NESDB, Agricultural Statistics of Thailand

All local currency data converted to U.S. $ at an exchange rate of U.S. $1.00 = BAHT 20.0

firewood and diesel or fuel oils are far superior to lignite.

Cured leaves are hand-sorted into some 26 different grades. Grades depend in part on the original structure and size of the green leaves, but even more so on the subsequent curing process. The ideal leaves are of uniform, yellow color, have a thin to medium body, bright shade, clear finish, fairly fine texture, oily, ripe, firm and strong, small to medium size fibers and have less than five percent injury.[1] If temperatures during the cure are too low, leaves will stay green; if they are too high, the leaves will turn brown and crinkle. Either way, they lose value. Depending on grade, export prices (in 1978) varied between US$0.50 to US$3.00 per kg (฿10 to ฿60); the average price amounted to US$1.50.

According to industry sources, woodfuel provides the easiest temperature control, followed by diesel or fuel oil. Lignite, although it has been used extensively in recent years,[2] is very hard to control and has a strong tendency to overheat. This affects both quantity and quality. For wood or oil-cured tobacco, the fresh to dry leaves weight ratio is 7 - 8 to 1; for lignite-cured tobacco it is on average 9 to 1, a weight loss of some 15 to 20 percent compared to the former. Because the quality of the cured leaves are, on average, also lower, the value of the finished product from the lignite-cured shed is considerably lower; these differences may amount to between $200 and $300 per barn load, or $0.50 to $0.75 per kilo.

Use of lignite has other problems attached to it. Deliveries from the mine are unreliable; sometimes a truck will have to wait several hours to

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[1] Thai Leave Tobaccos", Thai Export Bulletin, No. 5. Bangkok, 1967, p. 16.

[2] Production at Li amounted to some 100,000 tons per year, of which perhaps 80,000 tons were used by the tobacco curing industry.

get loaded. The quality of the lignite supplied is poor. Only about 70 percent is useable because of excessive breakage and admixtures of clay. Stored lignite has a tendency to self-ignite, and the water content of the lignite usually is high. Because of the temperature control problem, overheating of sheds is frequent, leading to fires. In 1977/78 one curing station lost 3 barns because of lignite-caused fires. Because the lignite has a high sulfur content, baffels and heating ducts must be frequently renewed. With lignite as fuel, baffels usually last only one or two drying cycles before they have to be replaced.

Lignite firing also requires more manpower. One man can supervise the firing of 2 or, at the most, 3 lignite-fired kilns; with oil or diesel fuel, he can supervise six.

The Economics of Lignite Versus Diesel Fuel

Given all of these problems related to the use of lignite it is not surprising that the tobacco industry is constantly looking for alternative fuels. One option offered by the Government are the use of forest stands in remote, high mountain areas. Costs of access, cutting and transport were found to be excessive. Another alternative under consideration is reforestation of overcut areas with fast growing species for the production of firewood or charcoal. Such schemes are under consideration, but would require a number of years for implementation and first harvest.

The only realistic fuel alternatives are either lignite or some hydrocarbon fuel, because wood fuels are in increasingly short supply.[1/] Government

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[1] In economic terms, the increasing shortage of wood and forest depletion as well as erosion problems resulting from overcutting imply significant external diseconomics associated with wood fuel use, i.e., the social cost of woodfuel use would be very high although data is not available for quantifying this value precisely. For an analysis of the physical dimensions of the problem see FAO, Timber Trends Study, Thailand, Rome 1972.

officials in Bangkok expect the Tobacco industry to greatly expand the use of lignite and predict a use of some 300,000 to 350,000 tons annually. Such a quantity would be sufficient to cover the total energy requirements of the industry. Industry spokesmen believe otherwise, and they strongly resist Government pressure to sign long-term, expanded contracts for lignite supplies. Instead they are rapidly converting their drying barns to the use of diesel or fuel oil instead.

Lignite, at present prices, is by far the lowest-cost fuel (see also table 2.) This is clearly apparent from the data of table 4, which indicate that the costs of lignite, delivered, per barn per year amount to only US$450 compared to US$1,325 for low-speed diesel fuel. However, the combined disadvantages of using lignite compared to diesel or fuel oil far outweight the initial price advantage. Additional labor costs increase the costs of using lignite by some $100 per barn per year.[1/] However, the major disadvantages of using lignite are a result of the poorer quality and reduced quantity of output resulting from the use of this fuel. Overall, the value of output of an oil-fired barn in market prices amounts to an average of US$7,500; from a lignite-fired one it is only US$5,250, a difference of US$2,250, or 30% of the value of output of the former. This differential dominates the initial cost advantage of lignite. The residual mark-up between selling price and fuel-cost related inputs plus raw tobacco is US$3,103 for oil-fired barns, but only US$1,628 for lignite-fired ones, a net difference in favor of the former of US$1,475, or 20% of the value of output.

It might be assumed that appropriate shadow pricing of the imported fuels versus the more labor-intensive lignite would substantially alter these

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[1/] Additional costs are coal storage, coal waste and higher handling costs; these are partially offset by the investment costs for oil burners, tanks and feedlines. Overall, these costs may mutually cancel out.

results in favor of lignite. This, however, is not the case, as can be seen from the economic data in table 4. Evaluated at the appropriate shadow prices the net advantage of oil-curing over lignite-curing is still about $1,069, or 16% of the value of output of oil-cured tobacco. This stems from the fact that about sixty percent of the tobacco -- particularly the higher quality leaves -- is exported, and that the main difference resulting from the use of diesel oil is a large increase in the total value of output. This increase is larger than the increase in the shadow-priced economic costs of the imported diesel fuel. Hence regardless of the magnitude of the foreign-exchange shadow coefficient,[1/] it is economically always more efficient at prevailing fuel market prices to use diesel instead of lignite.[2/]

This conclusion, of course, holds only within certain fuel price limits. As import prices rise for diesel fuel the market as well as economic advantage of diesel compared to lignite steadily shrinks. Assuming that all other costs and prices remain constant, the diesel import market price at which lignite is competitive with diesel is ¢25/ltr., ($39.75/bl.) or ¢28/ltr. at the pump.[3/] This translates into total fuel costs per barn per year of $2,800, a cost sufficiently high to eliminate the original advantage of the diesel. Evaluated in economic terms the import price for diesel would have to rise to about ¢23/ltr. ($36.98/bl.) until equivalence with lignite is reached. Hence, once

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[1/] Since foreign exchange serves as the numeraire in our evaluation, increased scarcity would result in a downward adjustment of all domestic shadow-price coefficients relative to foreign exchange.

[2/] This assumes, however, that the social value of additional foreign exchange earnings accruing to private tobacco traders is equal to the shadow price of additional imports. This may not necessarily be true.

[3/] This price is 210% higher than the ¢13.3/ltr. ($21.07/bl.) used in the analysis.

TABLE 4

FUEL-RELATED INPUTS, OUTPUTS AND THEIR MARKET AND ECONOMIC COSTS AND REVENUES IN TOBACCO CURING PER BARN PER SEASON

1978 Costs and Prices; US$1.00 = ฿ 20.00

ITEM	OIL-FIRED CURING			LIGNITE-FIRED CURING		
	QUANTITY	Value or Cost at Market Prices US$	Value or Cost at Shadow-Priced[6] US$	QUANTITY	Value or Cost at Market Prices US$	Value or Cost at Shadow-Priced[6] US$
Uncured Tobacco	37.5 tons	3,000	3,000	37.5 tons	3,000	3,000
Labor (curing only)[1]	60 man-days	72	22	144 man-days	172	52
Fuel, diesel, lignite	10,000 ltr.	1,325	1,257	30 tons	450	234
Sub-Total		4,397	4,279		3,622	3,286
Output, Cured Leaves	5.0 tons[3]	7,500[2]	6,873	4.2 tons[3]	5,250[4]	4,811
Remaining Margin[5]		3,103	2,594		1,628	1,525
Net Gain From Oil-Fired Curing		1,475	1,069		0	0

SOURCE: Thai Tobacco Industry

[1] One laborer can handle 6 oil-fired barns simultaneously, but only 2-3 lignite-fired ones; assume 8-hour days @ US$1.20/day, 3 shifts per day, 120 day season.

[2] This is the average selling price which, however, includes sorting, packing, transportation, etc.

[3] Ratio uncured/cured 7.5/1 for oil-fired and 9.0/1 for lignite-fired barns.

[4] Average assumed selling price for lignite-cured tobacco $1.25/kg ($1.50 for oil-cured).

[5] The remaining margin contains a few fuel-specific costs for which no unit costs could be ascertained. Among them are the costs of burners, valves, fuel tanks and lines for oil or diesel, the costs of the concrete-lined baffles (see text), or of the coal storage sheds.

[6] The import costs of diesel ($1000) are evaluated at the border price, and the remaining $325 at the standard conversion factor. The shadow price coefficient of unskilled labor in northern Thailand is equal to 0.3. The lignite coefficient is estimated to be 0.52 on the basis of labor, transportation and capital goods inputs. The standard conversion factor of 0.791 is applied to the 40% of tobacco sold in domestic markets; the remaining 60% of exports are evaluated at the border price equal to 1.

diesel prices reach or exceed this level policy measures such as taxes or direct fuel allocations should be introduced to force a switch to lignite, even though market prices still would favor the use of diesel fuel.[1/]

If these industry-supplied data truly reflect the average values of output and input costs, it is clear that the industry will continue to convert its curing operations from lignite to diesel or fuel oil as quickly as possible. This will be the case even if the recent, (1979) OPEC price increases for hydrocarbon fuels are fully passed on to users by Thailand's fuel pricing authorities. For similar reasons it appears that from a national economic perspective the use of imported petroleum-based fuels is preferable to the utilization of domestic lignite, as long as their costs are below $37 per barrel, and other costs remain constant in real terms.

IV. SOME POLICY ALTERNATIVES

Other potential domestic fuel sources are wood or charcoal, crop residues or natural gas. Wood is eminently suitable, but in short supply within a reasonable radius determined by transportation costs. Its costs on a heat-content basis already are as high as those for petroleum-based fuels (see table 2). Some formerly forested land unsuitable for general agriculture[2/] is available in the region for the establishment of forest plantations. However, even fast-growing species[3/] require at least six to eight years until

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[1/] This assumes, of course, that all other cost and prices remain constant. If not the appropriate switching prices have to be recalculated.

[2/] Because of continuing population pressure on the land forest plantations could probably not be protected and maintained on potential agricultural land.

[3/] Such as Leucaena, which may produce as much as 35 cubic meters per hectare per year.

harvesting can begin. In any case, it appears unlikely that sufficient land can be found to satisfy both the needs of the tobacco curing industry and the competing and growing demands of households, commercial and other industrial enterprises.[1/]

Experience has shown that locally available crop residues, mainly rice straw, is not suitable for tobacco drying because of handling and temperature control problems. Natural gas cannot be brought into the area because pipeline costs from Bangkok would be prohibitive. Shipping uncured tobacco leaves to the pipeline terminals near Bangkok would be equally impractical because of added transportation costs, product deterioration in transit, the need for constructing completely new drying facilities on high-priced land near Bangkok, and the difficulty of getting skilled temporary labor for curing and sorting of the uncured tobacco leaves.

This leaves the seemingly qualitatively and economically inferior lignite as the only major alternative fuel source. However, the conclusions derived above about its various disadvantages hold only because, as utilized at present, it is a low-quality, unreliable and difficult to manage fuel. But lignite does not have to be utilized as mined. Technological methods to upgrade raw lignite into a more uniform product are well known and have been in use in other countries for many decades.[2/] These up-grading methods usually consist of washing, cleaning, drying, milling and briquetting. The resulting product, in the form of briquettes, is of uniform quality, allows controlled burning, and is widely used by industry and households in lignite-rich countries.[3/] Once disdained as an inferior fuel when fuel oil prices were $3 to $4 a barrel,

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1/ Some 98% of all rural households use either wood or charcoal as primary fuel. From: FAO, Timber Trends Study of Thailand, Rome, 1972.

2/ As in East and West Germany and Czechoslovakia, for example.

3/ For example, some 20% of the lignite produced per year by the Rheinisch-Westfälische lignite mines in West Germany are converted into briquettes for such uses.

at between $20 to $40 a barrel lignite briquettes look attractive for many uses.

Lignite briquettes of uniform quality and size would overcome the major objections against lignite use for tobacco drying; the lack of control over the burning rate and, hence, the rate of temperature increases. Transport, storage and handling costs for briquettes would be higher than for diesel or fuel oil, but these differences are minor compared to the cost differential between lignite and petroleum-based fuels on a heat content basis.

Conversion of lignite into briquettes would increase the costs of the fuel. In 1978, a small-sized briquetting plant based on the Li deposit was under construction, with a target production date of summer, 1979.[1/] Its design capacity was 12,000 tons of briquettes per year, destined mainly for an acetylene plant and other local users. Total capital costs of the plant were estimated at US$750,000 and projected sales prices for the briquettes were $70.00 per ton.

West German manufacturing sources of briquetting plants estimate that the total installed costs of a highly mechanized plant at Li, for an annual capacity of some 500,000 tons, would amount to about US$103 million. Assuming a life expectancy of 30 years, capital cost charges for such a plant would be $24/ton at a real opportunity cost rate of 11%, and $62/ton at a market discount rate of 30%. For such a highly automated plant labor requirements would be only 30 men per shift.

These somewhat sketchy cost estimates[2/] nevertheless indicate that lignite

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[1/] Derek Industry of Synthetic Coal Co., Ltd.

[2/] The data on the Derek Industry plant are somewhat more reliable since they were obtained when the plant was already under construction. The West German data are based on desk studies only, without detailed engineering site evaluations.

TABLE 5

BRIQUETTE PRICES PER TON THAT MAKES THEM COST EQUIVALENT TO DIESEL FUELS IN ECONOMIC TERMS[1]

Delivered Diesel Price[2]	Quantity of Briquettes Required, per Barn, Per Season Tons	Max. Allowable Economic Cost per Ton Delivered in Border Prices $	Equivalent Market Price with Shadow Coefficient of 0.803[3] $
$20/bl. = ¢12.57/ltr.	15	81.80	101.87
	20	61.35	76.40
	25	49.08	61.12
$32/bl. = ¢20.08/ltr.	15	131.20	163.39
	20	98.40	122.54
	25	78.72	98.03

[1]For underlying data see Table 4.

[2]Includes ¢3.25/ltr. (shadow-priced ¢2.57/ltr.) for domestic handling and delivery charges.

[3]Based on 80% cost share of manufacturing at a shadow-price of 0.86, 10% transport at 0.63 and 10% mining at 0.52.

briquettes are likely to be a competitive fuel for the tobacco curing industry. This can be seen from the data in table 5 which estimate a range of briquette prices that would make them cost equivalent with diesel fuels in real economic terms. The main assumption underlying the analysis is that lignite briquettes, because of their uniform quality, would provide the same controllability of barn temperature changes as do wood or petroleum fuels at present. Two diesel fuel prices were assumed. The first, of $20 per barrel, represents the delivered, shadow-priced 1978 fuel costs as used in table 4. The second, of $32 per barrel, approximates the average 1979 world market price. Several ranges of potential lignite briquette requirements were used. At present, average raw lignite requirements per barn per season are 30 tons (see table 4). However, lignite briquettes would have a higher heat rate per unit of weight, because they would be free from impurities, as well as dried, and have superior burning characteristics. On a comparative heat content basis, 10,000 liters of diesel fuel are equivalent to 15 tons of dried and clean lignite from the Li deposit.[1/] However, the burning efficiency of briquettes may be somewhat lower than those of diesel fuel burners that blow the generated combustion gases directly into the heat-exchanger pipes. How much lower this thermal efficiency would be can only be established through field trials.[2/] Such data are not available at present; hence, three ranges of briquette requirements per barn per year have been shown: 15 tons, 20 tons and 25 tons.

[1/] 6,200 Keal/Kg dry. From: National Energy Administration, Oil and Thailand 1977, Bangkok, p. 43.

[2/] Factors that will affect actual heat rates will be the cleanliness and qualitative uniformity of the briquettes; their moisture content; their shape, and the frequency and manner of stoking of the fireboxes, as well as the shape of the fireboxes themselves.

At diesel costs of $20/bl, maximum allowable delivered briquette costs per ton in terms of border prices range from $49, if 25 tons are needed, to $82, if 15 tons suffice. In equivalent market prices they range from $61 to $102 per ton. At diesel prices of $32/bl., which are more in line with post-1979 world market price levels, briquette costs per ton can range from $78 to $131 in border prices, and from $98 to $163 in market prices. At their lower bound[1/] these equivalent market prices are lower than the quoted market price of $70 of Derek Industry. However, a larger briquetting plant[2/] is likely to be more efficient so that even in this extreme case the briquettes are likely to be the more efficient alternative in both economic and financial terms. At all other prices, briquettes are clearly less costly than diesel in economic terms. From a national point of view, therefore, every effort should be made to promote the use of lignite briquettes for tobacco curing.

Unfortunately, the issue is not quite so clear-cut when the analysis is done strictly in financial terms, i.e. on the basis of market prices. Clearly, the results of the financial, rather than the economic analysis, will determine actual industry behavior, unless the government deliberately intervenes in the industry's decision process. Table 6 repeats the analysis of table 5 in financial terms. At prevailing 1978 diesel fuel prices, maximum delivered briquette costs must be as low as $53/ton if as much as 25 tons per barn per season are needed, or $88/ton, if 15 tons are found to be sufficient. The lower limit is below the quoted price of $70/ton from

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1/ At the 1978 diesel prices and with briquette requirements of 25 tons.

2/ Of at least ten times the capacity of the Derek plant.

TABLE 6

BRIQUETTE PRICES PER TON THAT MAKES THEM COST EQUIVALENT TO DIESEL FUELS IN TERMS OF MARKET PRICES[1/]

DELIVERED DIESEL PRICE	QUANTITY OF BRIQUETTES REQUIRED, PER BARN, PER SEASON TONS	MAXIMUM ALLOWABLE COSTS PER TON DELIVERED $
$21/bl. =	15	88.33
¢13.25/ltr.	20	66.25
	25	53.00
$33/ bl. =	15	138.40
¢20.76/ltr.	20	103.80
	25	83.04

[1/] Data based on tables 4 and 5.

Derek Industries, the only existing briquette producer at present. At average 1979 diesel fuel prices of $33/bl., however, the allowable briquette price range is more attractive - from $83/ton for 25 tons per barn to $138 for 15 tons per barn - substantially above the $70/ton Derek Industry price. Hence, if 1979 petroleum product world market prices prevail, and if domestic prices for lignite briquettes do not rise substantially relative to prevailing prices, briquettes are likely to be the more attractive fuel in strictly financial terms as well. This would obviously make it much easier for the government to persuade the tobacco curing industry to switch to lignite briquettes, provided, of course, that the technical assumptions about their suitability can be proved, and provided that the needed investment capital and know-how for the production of qualitatively acceptable lignite briquettes can be found.

With an estimated demand by the tobacco curing industry alone of between 120-200,000 tons of briquettes per year this would result in a new industry with a value of output of some $8 to 14 million;[1/] it would increase local employment;[2/] it would provide an opportunity for other users of heating energy to tap a new source of supply, reducing pressure on dwindling supplies of firewood and charcoal and, best of all, it would reduce dependence on hydrocarbon imports by another US$14 to 16 million or so per year.

For the Thai economy, this specific use of the lignite deposit at Li would mean that for a period of over 30 years a locally produced energy product would replace $14 to $16 million of hydro-carbon imports per year.

[1/] Based on the 1979 announced selling price of $70/ton of Derek Industry.

[2/] In mining, processing and transportation from the plant to the tobacco curing sheds. Additional employment of some 560,000 man-days would be created during the curing process from the greater man-power requirements of briquette compared to oil firing.

The present value equivalent of this switch-over would be between $122 and $139 million, evaluated at an estimated 11% opportunity cost of capital for Thailand. Considering that the foreign exchange costs of starting a briquetting plant to serve the needs of the tobacco curing industry is likely to be in the $10 to $15 million range, this appears to be a worthwhile investment, indeed.[1/]

V. CONCLUSIONS

A number of important conclusions with regard to energy use patterns in developing countries can be drawn from this specific case study. The first, and most important one, is that user choices among alternative energy sources will usually not only be determined by the financial costs of each alternative fuel compared on a net heat content basis. Equally, or more important, may be the auxiliary costs to the user of utilizing each one of them. These will be made up by the costs of labor, capital and land related to receiving, unloading, storage, handling, ease of control in use and potential risks, waste material disposal and system maintenance. Reliability of supply and transportation, uniformity of quality, and the effect on the quality of processed materials will be other important considerations. Habits, and the availability and reliability of experienced operators may significantly affect use. Particularly in situations in which the potential choice lies between a known, customarily-used energy material and new alternatives of unknown characteristics, resistance to change may be formidable. Lack of knowledge and experience is perhaps one of the most formidable barriers to change in energy use patterns, particularly in developing countries (although this was not a particular issue in the case of the Thai tobacco

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1/ Based on the Derek Industry capital costs. Proportional capital costs for a highly automated, large-capacity plant as proposed by West German sources would probably be in the $25 to $30 million range.

industry). Only if all of these factors are systematically and carefully taken into consideration will it be possible to bring about desirable changes.

Another important consideration from a national point of view should be that market prices to users frequently do not reflect the true, economic costs of the specific energy use. Appropriate shadow pricing is necessary to determine the difference, if any, and either changes in market prices or regulations affecting alternative fuel choices should be used to bring about a more realistic choice pattern reflecting real economic costs.

For governments, the fact of the rapidly rising, relative costs of petroleum products should act as a strong stimulant to establish energy-use oriented evaluation and development task forces that systematically analyze existing and projected future energy use patterns for major specific activities, and relate them to existing or potentially available sources of supply; these task forces should evaluate the true financial as well as economic systems costs of the various alternatives, and attempt to bring about desirable changes in energy utilization patterns in industry, commercial activities and households. In the majority of cases, this will not call for the introduction of new, exotic and unproven energy use or conservation technologies, but simply in the rearrangement and proper utilization of already existing ones.