DOMESTIC ENERGY PRICING POLICIES

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Prepared by
Rangaswamy Vedavalli
World Bank

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U.S.A.

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Abstract

Energy pricing continues to be the chronic issue for decision makers in the developing countries. Lower international prices offer some short term relief but the gap between domestic and international prices and relative price distortions between different forms of energy have not been significantly altered. Governments have been reluctant to price energy to reflect its economic cost because of their concerns on the adverse effects of energy price increases on industrial competitiveness, household budgets, (especially those of low income families), and on inflation in terms of both its direct economic effects and its longer term social and political ramifications.

The three papers in this volume address these concerns of governments and provide both a theoretical framework of general pricing principles and practical approaches for formulating domestic energy pricing policies. These papers were initially prepared for presentation to participants of Middle East Energy planning training course, represented by high level government officials from twenty Middle Eastern and African countries.

The first paper sets out a general pricing framework for formulation of domestic pricing policies for pricing of crude oil, petroleum products, and natural gas. The second paper examines the formulation of electricity pricing policy meeting the equity, economic efficiency, and financial viability criteria. In this regard, the paper discusses the long run marginal cost, (LRMC) approach as a framework for analyzing system costs and for setting tariffs. The third paper focusses on the need for evaluating the macro-economic implications, and analyzing the effects of energy price adjustments on industry, transport, and household sectors. In this regard the paper examines international experience of domestic energy price adjustments in the oil importing and the oil exporting countries, and presents alternative pricing policy options. A common theme that runs throughout the volume is that given the problems of debt and public revenue, the policy makers in the developing countries need to continue to pursue the goal of economic pricing of energy products and electricity. The present situation of low international fuel prices offers the best opportunity for completing the process of adjustment of domestic energy prices to reflect their economic costs.
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A. Introduction

1.1 The prices of energy products, both for appraisal of investment projects and for the market place, are a central tool of energy policy. The optimal choice of project design and development strategy hinges upon using the appropriate price of energy inputs in the selection process. In the marketplace, adequate price incentives must be provided to producers to stimulate exploration and development of indigenous supplies of oil, gas, coal, hydropower and other energy resources. Energy consumers -- many of whom are producers of other goods -- should face prices that encourage them to use energy efficiently and to select the right form of energy for their particular needs.

1.2 The objective of this lecture series is to provide the theoretical and practical approaches of domestic energy pricing policies. The first lecture would deal with the general pricing principles, the pricing of petroleum products and natural gas; the second lecture will deal with the pricing of electricity and the third lecture will deal with the selected issues of energy pricing policies.

B. General Pricing Framework

The Basic Model

1.3 Whether a price is determined in the free market by the forces of demand and supply (as shown in Figure 1), or whether it is set by a government regulatory body, if it is an "economically efficient" price such as $P_e$ in Figure 1), it will have the following three characteristics:

![Equilibrium Price Determination](image)

Figure 1. Equilibrium Price Determination


These Papers are based on material acknowledged in the References and Bibliography a copy of which is attached.
(i) It will clear the market. A higher price than \( P_0 \) would induce producers to supply more than the consumers were willing to buy at that price. Conversely, at a lower price than \( P_0 \) the consumers would demand more than the producers would find it profitable to produce at that price. A situation of over-production (excess supply) or shortage (excess demand) is often a sign that the current price is above (in the first case) or below (in the second case) the economically efficient price for that good.

(ii) It will encourage additional production (or exploration) whenever the expected costs are less than the expected value of incremental supplies. Thus if future production costs are expected to be higher than historical costs have been, and if the expected value of new production is yet higher than its expected cost, a pricing rule based on the average (i.e., historical) cost of production would be too low, and not give producers a strong enough signal to expand. Thus, it would not be an economically efficient price.

(iii) It discourages "wasteful" consumption. On the demand side, a price that is below \( P_0 \) will not ensure that available quantities of the good are used to the best advantage of the economy. It may also cause misallocation of other competing or complementary goods. For example, if coal prices are set below their economically efficient level, this may not only encourage wasteful burning processes, but it may also prevent consumers from switching, say, to natural gas even though that would be more economically efficient.

1.4 Since one cannot observe demand and supply curves directly and since, particularly in the energy sector, prices are often set by regulatory authorities rather than in the marketplace, it will usually be necessary to infer the efficient price level from observations of the supply and demand situation and how far the actual pricing regime deviates from these equilibrium conditions.
1.5 There are some special features of the energy market that require some elaboration of the simple version of pricing theory discussed above. When economies of scale in production are such that investment takes place in large, discrete amounts (rather than in the smooth increments shown as the supply curve in Figure 1), then the supply curve would look more like that shown in Figure 2. There, $Q^*$ and $Q^{**}$ represent, respectively, the current capacity level and the production capacity to be achieved by the next investment project in the country's energy development program. Until demand reached a level close to $Q^*$, the incremental cost of supplying an additional unit is simply the operating and maintenance cost, $P_1$ (shown here as constant over all production levels). As the demand grows to a level that presses upon the current capacity however, the marginal cost begins to rise sharply. The marginal cost, and therefore the price, would eventually reach $P_2$ — a very high level which includes the full investment cost needed to achieve the capacity expansion to $Q^{**}$. Then, once the investment is "sunk", the marginal cost of supply, and thus the price, drops back again to the operating and maintenance cost, $P_1$.

![Figure 2. The Effect of "Lumpy" Investments on Price Determination](image-url)
1.6 The sort of erratic price behavior generated by such a strict adherence to theory would be difficult for consumers to accept and, in the absence of perfect foresight, would cause them to make long-term investment decisions that might be uneconomic as prices peaked to permit capacity expansions. A solution to this problem, which has been widely adopted in electric power, natural gas and other public utility pricing, is to price at long-run, rather than short-run, marginal cost. By so doing the consumer faces a smooth price path where each price (over time) includes a contribution toward future investment calculated along the long-run marginal cost (LRMC) price path.

**Tradeability**

1.7 A second modification to the simple pricing theory shown in Figure 1 is required to reflect the tradeable nature of energy resources such as oil, gas and coal. The demand curve facing a small producer in the world market will contain a horizontal section corresponding to the export price ($P_x$) at the producers border. Similarly, the small consumer in the world market will be able to import the goods at some price ($P_m$) where the supply curve (including imports) becomes good. In 3(a) domestic demand and costs are such that the efficient price ($P_e$) is between the export and import equivalent prices for the good, and the good is neither imported nor exported. In 3(b) the import price is the economically efficient one for domestic production, whose costs reach that level before domestic demand is met. At that price $Q_p$ is produced and $(Q_c-Q_p)$ is imported to satisfy total domestic consumption $Q_c$. In Figure 3(c) the proper domestic price is the export value, $P_x$, at which $Q_p$ of the good is produced, $Q_c$ is consumed.

![Figure 3. The Demand and Supply Curves for A Tradeable Good](image)
domestically and the difference \((Q_p-Q_c)\) is exported. For a tradeable good the correct price -- whether it is import equivalent, export equivalent or LRMC -- can only be determined empirically by the relative costs of import, export and domestic production and the level of domestic demand.

1.8 The difference between the import price and the export price of a traded good is the cost of transport and handling the good in trade. Thus, for a commodity such as crude oil whose transport cost is low relative to its well-head price, there will be only a small wedge between \(P_x\) and \(P_m\), and in nearly all countries the efficient price will be either \(P_x\) or \(P_m\). For coal, however, transport costs make up a much large component of the final price to the consumer. For example, for coal imports into western Europe in 1982, transportation (inland and ocean) was estimated to account for about 45% and 60% of the delivered cost of US and South African supplies, respectively. Because of these high transport costs, for many countries the market-clearing domestic coal price will be between coal's import and export values. This is one of the reasons why less than 5% of thermal coal consumption has historically been traded. High inland transport costs may also create a segmented coal market within a country, where different pricing structures will be appropriate for different coal regions.

1.9 There is sometimes confusion about the relevance of traded, or "border", prices for goods that are not actually imported or exported by a particular country. As long as a locally produced good substitutes at the margin for a traded good, its value is tied to the price of the traded good. Thus lignite (which is not actually directly tradeable) may on the margin substitute for imported coal, for example, or may free locally refined fuel oil for export. In either case, its value would be the suitably-adjusted price of imported coal or exported fuel oil. On the other hand, if lignite does not substitute at the margin for traded fuels, its value will be determined by LRMC plus whatever depletion premium might apply. A situation might arise where in one region of a country lignite is expected to face LRMC lower than, say, imported coal prices. If imported coal is still consumed, however, the value of lignite will on the margin, and while imported coal is fully displaced in pertinent uses, be the quality-adjusted price of imported coal. But once coal is displaced, the value of incremental lignite production will fall to LRMC (plus probably a depletion premium). Therefore, pricing lignite at import parity can under those circumstances only be justified in the short or medium term. Setting the price of lignite just below import parity for a period might encourage producers to accelerate capacity expansion to allow for a faster substitution process, while still providing incentives to consumers for fuel switching.

**Depletability**

1.10 Oil, natural gas and coal come under the economic theory of exhaustible resources. Since the stock of these resources are fixed, consumption of one unit of these resources today implies foregoing its consumption at some future date. The value of this foregone consumption has been called by different names in the economic literature: depletion premium, royalty, user cost, net price or resource rent. Thus the true economic cost of a depletable commodity consists of two elements: the extraction cost and the resource rent.
1.11 The fundamental principle of depletable resources, initially spelled out by H. Hotelling in 1931, is that under equilibrium conditions and a set of rather restrictive conditions\(^1\), the market price of the resource, net of its extraction costs, must increase over time at a rate equal to the opportunity cost of capital. This principle can perhaps best be grasped by imagining a case where the resource rent (the market price minus extraction cost) rose at a rate lower than the interest rate. In such case, a profit maximizing firm would extract and sell its whole stock as soon as possible, investing the proceeds in alternative areas which yield the rate of interest. Any delay could only reduce the present value of the firm's profits. On the other hand, a firm facing a net price that is rising faster than the rate of interest on alternative investments would have every incentive to leave the resource in the ground to appreciate. A resource rent rising at the opportunity cost of capital is therefore an equilibrium condition in the asset market as well as the market for output. Only such a trend in the net price is compatible with a positive output in every period (because firms will be indifferent as to the time at which they sell) while resource owners will, at each period, be just content to hold the stock available.

1.12 In order to calculate the resource rent at any point it is necessary to know its demand curve. As the price of the resources grows over time the demand for it naturally falls (other things equal), until the resources is just exhausted as the price has risen so high that the demand has fallen to

![Figure 4. The Price Path of a Depletable Resource](image)

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\(^1\) These conditions include perfectly competitive markets both for current and future goods and certainty as to the stock of the resource and the current and future shape of the demand curve.
zero. A common illustration of how this works is shown in Figure 4(a). There
the demand curve is such that at some limiting price, $p^*$, the quantity of the
resource demand falls to zero. A common justification for this in the energy
field is that some alternative source of supply (or imports) will become
available when the price reaches a sufficiently high level. This makes the
computations easier, but is not a necessary assumption. If the demand curve
rises asymptotically toward an infinite price, the resource rent does the
same, and the quantity demand falls asymptotically toward zero. In such a
case, the resource is never fully exhausted. In Figure 4(b), the curve with
the arrows shows the price path of the resource, with its exhaustion date $T^*$,
where its price has just reached $p^*$ and demand has fallen to zero. The
parameters needed to derive that path (and thus $T^*$) are the demand curve, the
marginal extraction cost of resource over time (here assumed to be constant),
the initial stock of the resource and the relevant rate of interest over time.

1.13 Much recent research has gone into exploring the results of the
Hotelling theory and into relaxing the conditions under which it is valid.
The general thrust of it is that with diverse assumptions such as
technological change reducing the extraction costs or the discovery of new
reserves, it is possible to cause the market price of the resource to move
along almost any time path, even declining ones. However the basic result
that the price of a depletable resource will have two additive elements -- its
extraction cost and a resource rent -- and that the latter will rise over time
at the discount rate (toward whatever substitution point the demand curve
dictates) is a robust one over a wide set of assumptions.

1.14 It is worth noting that at $T^*$, the date at which substitution for the
resource at the margin begins, either through imports or by some other, more
costly, domestic resource, the resource rent can be calculated in a
straight-forward way: as the difference between the extraction cost of the
resource and the marginal cost of the substitute resource. Thus, for example,
if the power sector in Country X must begin to import coal in 1995 to
supplement supplies of domestic coal, then the resource rent path of domestic
can be calculated by discounting back (at the opportunity cost of
capital) from the full difference between the costs of imported and domestic
cal in 1995. From 1995 until the domestic coal is exhausted, its resource
rent remains the difference between its own cost and the price of the
substitute.

1.15 Two further points can be made about the general application of the
Hotelling principle to energy resource prices. First, in cases where domestic
reserves are very large relative to demand (say, 50 years or more) and where
exports are unlikely or impossible, the resource rent will be a theoretically
valid but quantitatively insignificant component of the economically efficient
price. The margin of error around attempts to estimate demand, the discount
rate and the reserve base 50 years into the future is almost certain to swamp
the size of the rent itself. From a practical perspective, in such cases it is
probably better ignored.

1.16 Secondly, where an energy resource, e.g. coal will be replaced at the
margin by another indigenous, depletable resource such as natural gas
(presumably because it is cheaper than imported coal) which, in turn, has a
resource rent based on its eventual replacement (say, imported coal), the
calculation of coal's depletion premium will be a complex problem. This situation is shown graphically in Figure 5. There coal is used for the period \( T_c - T_e \), during which, at \( T_q \), it begins to be substituted by more costly natural gas. Gas is exhausted at \( T_g \), shortly before which (at \( T^* \)) it has become necessary to begin using imported coal. The exhaustion dates and the price paths for gas and coal would have to be determined simultaneously taking into account the demand for electricity (if that is their primary market) and the power system expansion plan).

![Figure 5. The Price Paths of Substitute Depletable Resources](image)

1.17 To summarize, for countries whose coal/gas reserves are either very large relative to domestic demand or fairly small, the depletion premium presents little problem since it is quantitatively unimportant in the first case and straightforward to calculate in the second. In the intermediate cases, however, it may be large enough to be important, and its calculation will require estimates of future extraction costs, the demand pattern, the long-run trend of the discount rate, the reserve size and the future price of the substitute. The problem of dealing with uncertainties around these estimates will be increased when coal/gas will be replaced, at the margin, by another indigenous resource rather than imports with an exogenous value.

The Three Price Levels

1.18 "Price" in economic theory is not one but three.

(i) The market price, means that the current rate of exchange of money against goods. In particular, what is being paid today for a large-volume stream over an appreciable time ahead.

(ii) The competitive supply price indicates the tribute to nature. The least that needs to be paid to bring forth the stream of outputs.
This can only be found out by analyzing the outlay for an investment made at one point of time, and the rate of output it will generate, i.e. development cost.

(iii) Reference price which measures the expected benefit of the investment as against its cost. Since the investment is only made in hope of profit, the decision to invest will only be taken if the expected revenues will exceed or at least equal the supply price. Under perfect competition, which is unreal, but useful as absolute zero in physics, these prices become one. The price-production system is in complete equilibrium, and there is no incentive to increase or decrease the rate of output. The study of real markets is a study of how these prices diverge and of the forces generated thereby. Understanding of this is crucial for formulating domestic pricing policies. Divergence occur all the time by human error and changes in desires and technology. Demand may be greater than expected, raising market price. The second basic reason for divergence is market control and how the market structure functions. Whether it is a single firm, or group monopoly, or oligopoly or a competitive market.

C. Petroleum Prices

Economic theory of world oil market

1.19 The crude oil industry, contrary to common belief, is inherently self-adjusting under competition, the level of output, and its division among various sources of supply are set by the price acting upon the cost of bringing up more output. This incremental cost, for every individual unit and for the system as a whole, increases rather than decreases with greater output. So long as incremental cost is less than anticipated price (or net revenue), there is a profit incentive to produce more; when the cost rises above the price, it chokes off further expansion. The spasms of the world oil market express both a strong adjustment mechanism and the very formidable barriers to the working of the mechanism.

1.20 The adjustment mechanism is always under strain because of changes in cost or demand. The prices and costs that count are always those expected in the future. Hence changes in expectations and changes in the rate of discounting must affect the relative costs of different supply areas and the industry as a whole. Peculiar conditions applicable only to petroleum are unpredictability about future discoveries and the extent of the reservoir. Thus, the concept of discovery "cost" ex-ante is too vague to permit calculation of cost.

Pricing of Crude Oil

1.21 For nearly forty years after the end of World War II crude oil was priced in cargo lots f.o.b. point of shipment, leaving the buyer with responsibility for transport and insurance to the refinery. So each crude stream, defined in terms of specific gravity and sulphur content, had its own price. The original system whereby oil companies 'posted' their prices (which were subject to discounting for quantity) was superseded in the 1970s by a
structure of government sales prices, all fixed in relation to an OPEC-determined quotation for the 'marker' crude (Arabian Light). In fixing the relationship between a given crude and the marker, account was taken of location relative to main markets, product yield-pattern, and quality differences such as sulphur content and wax content.

1.22 The problems associated with maintaining this system of government-administered prices are familiar enough. First was the need to obtain agreement from thirteen different governments on the level of the marker crude. The difficulty of doing this emerged in 1976-77 and became temporarily insoluble during the 1979-80 escalation, when Saudi Arabia refused to go the whole way with those who advocated higher oil prices. The resulting two-tier price structure was eventually unified at Geneva in October 1981, when the level agreed was far above the short-term equilibrium price. The result was that the OPEC had to commit itself to accepting production programming to reduce the market supply -- with all the headaches which that entailed.

1.23 The second stage in the price-fixing process was that of agreeing differentials for all the other crudes. Ideally, these should accurately reflect the preferences of refiners -- which change from time to time and are not the same in different markets. In practice it was seldom possible to avoid a mismatch between the government-administered price structure and the preferences of refiners -- a difference which created marketing problems for some sellers. The difficulty of maintaining accurate differentials was aggravated by the excess supply which was constantly pressing on the market. In the autumn of 1985, the traditional system was tacitly abandoned.

Netback Pricing

1.24 The situation in 1985 was that in the prevailing oversupply situation the attempt to maintain prices at too high a level had forced exporters to make production cuts that were deemed to be unacceptable. Saudi Arabia, was the worst hit, with its output falling at one point to 2.2 mb/d, against its official quota of 4.35 mb/d. The Saudis' problem was to find a way of forcing an extra 2 mb/d of oil on to Atlantic outlets from which, in the prevailing buyer's market, it had been squeezed out by the locational disadvantage suffered by long-haul Middle East crudes. In the circumstances, the adoption of the netback pricing formula probably provided the only way in which the objective could be attained. Competitive pressures soon forced other exporters to follow suit.

1.25 Netback pricing, which relates the price paid for each consignment of crude oil to the value of the output of products derived from it, is simple and rational in principle, but complicated in application. The two parties to the contract have to agree about the measurement of freight costs, the yield pattern of the refinery, the prices to be taken for each of the individual products made, the refiner's allowable margin, and the time-lag to be applied. In other words, they have to agree in advance on a formula by which the price of the crude is to be calculated. Each contract is unique, the agreed terms are generally confidential, and the exporter does not know at the time of the sale what price he will eventually receive. So there is a profusion of formulae, and buyers cannot be certain what their competitors are paying.
1.26 From the buyers' (refiners') standpoint the new system removed the risk of loss that could previously result from a drop in the spot price of the crude while on its way from shipment port to refinery. With a guaranteed margin written into the contract, some loss-making refineries became profitable once again. The new system also tended to remove the price discipline previously in force: refiners chasing the 'marginal barrel' of business by price-cutting suffered no loss because the formula probably enabled them to pay less for their raw material. They were also relieved of the compulsion to switch from one crude to another (to adjust their yield patterns and so maintain their margins) when individual product prices weakened. Incidentally, the role of the broker declined in importance.

1.27 Because buyers were willing, indeed keen, to sign contracts on the new basis, the change of policy was successful in the sense that it stimulated sales of Middle East crude, especially Saudi crude. (Mid-East production rose from 8.8 mb/d in August 1985 to 13.7 mb/d a year later, while Saudi production jumped from 2.2 mb/d to 6.4 in the same period.) The fact that the new system substituted term sales for spot sales was thought to be a stabilizing factor. But nothing could disguise the fact that the buyer's price gain was the seller's loss. Netback pricing was essentially a sophisticated mechanism for price-discounting with the object of boosting sales. As the exporting countries competed with one another by offering more and more favorable netback arrangements -- including substantially discounted netback prices -- the market collapsed. It soon became apparent that the extra exports had been secured at a heavy cost in terms of reduced oil revenues.

1.28 One general consequence of netback pricing is that it has covered the market scene with a veil of obscurity. It is no longer possible to give an exact reply to questions about the price of any particular crude, for the price is not determined at the time of sale and the oil will be worth different amounts in different markets. (One may calculate, for example that the netback value of Saudi Light in the first week of October 1988 was $11.98 a barrel in the USA, $10.56 in Western Europe, and $10.09 in Singapore; and that the corresponding values for Aral Heavy are $9.75, $8.40 and $7.91; but this does not tell us what the exporter will eventually receive for this month's shipments). Prices fluctuate daily and the seller is able, if he so desires, to discriminate between one buyer and another.

1.29 Formula pricing of this kind is manifestly no recipe for market stability; quite the reverse. In the circumstances of 1986 it has had an inherent tendency to depress the average price level because, as already pointed out, it encourages refiners to expand sales by offering price concessions; and, with crude supplies abundant, lower product prices are immediately translated into lower crude prices. If the buyer had to purchase extra crude at a fixed price, the upshot would be different.

1.30 As to whether netback pricing is here to stay, there is a conflict of opinion. One view believes that "netback contracts will be a dominant mechanism for distributing crude oil in the foreseeable future" -- partly because the price discrimination which is thus possible enables sellers to hold buyers. This view is based on a further belief that the retention of netback pricing over the next few years will drastically alter the way in which product stocks are managed; that it will tend to widen price


1.31 Other observers take the view that netback pricing represents a transitional stage that will soon pass. How, they ask, can a system which charges different prices for the same crude stream be expected to endure? They believe that refiners with adequate upgrading facilities and consequent flexibility of operation will prefer to 'shop around' on the spot market rather than tie themselves to a particular supplier by a netback contract. In the end, however, the answer must surely depend on whether sellers or buyers of crude gain the upper hand.

1.32 It is equally evident that a price level of $17-$19 (or higher) cannot be established and maintained with the present volume of consumption unless supplies are brought under OPEC control - either with or without the support of non-OPEC suppliers. Once control of supplies has been secured, the rest is relatively easy. There will then be no point in OPEC members continuing with a system that transfers all the risks from buyers to sellers and leaves the sellers' proceeds indeterminate at the time of sale. If we assume that the governments can eventually reach a common mind on the imposition of production limitations, the corollary must surely be the early disappearance of netback pricing.

OPEC options

1.33 This does not necessarily imply a straightforward return to the previous pricing system. In fact, OPEC experts have been exploring a number of possible alternatives for consideration by the OPEC's pricing committee. The experts point out that there must be a marker crude, the price of which is fixed by Conference and to which the other prices are related. The marker could be a single crude - one which is widely traded, with characteristics which conform broadly to the OPEC average. The ideal stream for this purpose would (as before) be Arabian Light. The advantages of using only one crude are that the marker price is immediately apparent to all, that the level of output needed to support that price can easily be identified, and that the price differentials for other crudes can be readily calculated. The disadvantage, as Saudi Arabia discovered, is that demand fluctuations have to be absorbed in the first instance by adjusting the supply of the marker. In the light of past experience, the adoption of a single crude as marker seems doubtful.

1.34 The only other way is to choose a collection of crudes, whose weighted average price would serve as marker. For this purpose either a few crudes (say six) could be selected or all the mainstream crudes (say twenty). The selected streams could be separately priced, while the weighting used to work out the average could be proportional to production in a base period - say the years 1980-85; alternatively, the average could be fixed first and the individual prices derived from it. A still wider possibility would be to base the marker on the weighted average price of selected non-OPEC crudes, or on a mix of both OPEC and non-OPEC oils.
1.35 However the marker price is devised, the OPEC's basic problem remains that of distributing the production quotas required to sustain the agreed price level. Equally important is the cooperation of non-OPEC producers. So the question whether the netback system survives into future or what the behavior of future oil prices may well be decided by the behaviour of the world oil market.

D. The Refined Products Price Structure

Basic Economics of Joint Supply in Refining

1.36 A given price or margin may at any given time be temporarily below (or above) the level necessary to evoke a permanent supply of the product at the current rate of output. If costs (including the necessary return on investment) are not covered, supply shrinks and price rises. So much for the total refining margin. But individual petroleum products are joint products, and it is altogether useless to seek or to pretend to have found the costs of the individual products costs that do not exist. Refining a ton of crude oil is profitable, and will be done if the receipts cover the total costs of the operation, including the necessary profit. Here, distinction should be made between short-term and long-run incremental cost. When and if a refinery is working at less than optimum percentage of capacity, an additional barrel can be produced at a low cost, below the average cost; then the price of the refined product is under downward pressure. On the other hand, when a refinery is pushed toward maximum output, the cost of the additional barrel becomes higher and higher because of storage cost, product deterioration, lack of normal downtime for maintenance, clearing and repair, etc. In general, incremental cost rising with higher output expresses the resistance of output to expansion, and gives the signal that production is pressing against the limits of capacity. When this situation is expected, or when it arrives unexpectedly, it is time to plan for expanding capacity. Thus the reckoning of short-term incremental cost - that of making the best choice given the present capacity - is replaced by considering long-run incremental cost - that of adding the best type and amount of additional capacity; either in a new refinery or in an addition to one already on stream.

1.37 In general, when a branch of the economy is rapidly expanding, its incremental cost is a mixture of short and long-term, and is higher than the current or future incremental cost at optimum levels of output. But even with no pressure on the price of the whole output, there can surely be a surplus of any particular product available at a very low incremental cost. For when products are joint in variable proportions, the incremental cost of a single joint product does exist within certain limits even if its average cost does not. For example, heavy fuel oil is a simple combustible, which is worth no more than any other source of heat, allowance being made for handling costs a little lower than coal and a little higher than gas. All other refined products have higher value uses with no near substitutes. Therefore the HFO price cannot go appreciably above the price of crude oil, for if it did, consumers would burn the entire crude. But the HFO price can go to zero or even below. (If natural gas were available at very low prices, HFO's value would be negative since there would be a cost of disposal). The incremental cost of more severe cracking would then be in part offset by the saving in disposal cost, in addition to the value of higher products secured.
1.38 But the prices of other products cannot go below the price of crude, for then it would not pay to refine them out. They would have only fuel value. Therefore the basic rule is: the more are prices of other products above crude oil, the more is heavy fuel oil below it. Conversely, the nearer the prices of other products are to their lower limit (the price of crude oil), the closer is heavy fuel oil to its upper limit, which is also the price of crude oil. At the limit, there is no longer any refining.

1.39 So far, the assumption is the refining margins were competitively determined, so that incremental processing costs and prices stayed close together. It is competition which keeps the price of heavy fuel oil below that of crude permanently and in long-run equilibrium.

Determination of Ex-Refinery Prices.

1.40 Import Parity principle includes landed cost of products:

(i) f.o.b. prices;
(ii) marine freight from the source of imports to the ports;
(iii) marine insurance;
(iv) ocean loss;
(v) basic customs duties and surcharges;
(vi) wharfage or river dues;
(vii) other compulsory landing charges, such as charges for pumping, customs, supervision, etc.

1.41 The total of all these items constitute landed cost. To this should be added marketing and distribution charges to arrive at the selling price. The advantage is that it would provide a reasonable incentive to maintain internationally competitive standards of efficiency in operating the refineries.

1.42 Two disadvantages: first, problems posed by the existence of inland refineries. Second, parity pricing could include elements which unjustifiably raise the ceiling of ex-refinery prices which in turn inflate the profits of the refineries. The main thrust of the argument is what actually imported is crude oil, while freight charges which are higher for products than for crude oil are charged. Also import parity does not pay attention to the actual cost of production of the local refineries.

Alternative to Parity Pricing

1.43 Cost-Plus Pricing includes cost of crude oil plus a refiner's margin to cover the operating cost as well as a reasonable profit margin. From an economic point of view, cost-plus pricing raises two basic issues. The first is the problem of deriving a price structure which ensures a reasonable profit margin to refiners and at the same time gives rise to a pattern of production
consistent with the pattern of consumption of petroleum products. In the refining industry with int costs the best that can be attempted is to relate total costs to the total value of products to ensure adequate profit margin. The relative price structure has to be set taking into consideration the actual consumption pattern in such a way that the ultimate price structure will minimize product imbalances and maximize the net back value. Another disadvantage of cost-plus pricing is the tendency towards cost-plus and inflated prices. The criterion is whether this would result in lower costs than import parity pricing. A cost-plus system of pricing has an inherent defect in reducing the incentive to economize on costs, particularly if the demand for the product is relatively inelastic there is a tendency for costs and prices to be unduly inflated. From the economic efficiency considerations cost-plus is not likely to be an effective substitute to parity pricing.

Modification to Parity Pricing

1.44 The main thrust of the argument against import parity pricing is that it contributes to an inflation of ex-refinery ceiling prices, because of the difference between the freight rates, wharfage and other landing charges allowed for products in the calculation of import parity prices while these charges actually incurred are for imports of crude oil. These over-pricing differentials can be eliminated by substituting for them the charges applicable to the importation of crude. In this way, a modified parity formula may be retained to include f.o.b. prices of products and all other elements in the parity formula fixed at the rates applicable to the importation of crude oil (except custom duties).

1.45 The rationale for allowing domestic refineries to price their products ex-refinery on a modified import parity basis is that it would allow them to earn a refiner's margin similar to that applicable to the international refineries assuming comparable levels of efficiency in refinery operations.

E. Natural Gas Pricing

1.46 An appropriate strategy for natural gas development should have as its main objective the maximization of net benefits to the country from the use of its exhaustible gas resources. This objective has three important dimensions, each of which implies certain pricing principles. First, there must be the incentive to promote efficient use of the gas. Gas prices must be neither so high as to inhibit consumption (especially where the users must incur some cost to switch from other fuels), nor so low as to encourage wasteful use. Secondly, there must be adequate incentive to explore for and produce the gas. Particularly in cases where the government may be able to attract foreign capital to assist in gas development, the provision of an appropriate pricing and contractual framework is essential. Finally, the growth rates of both supply and demand for gas should be rapid and matched up to the level where full development has been reached. As discussed below, the basic principle that facilitates the achievement of all three objectives is that both consumer and producer prices should be set near the marginal opportunity cost of the gas. Excess producers' or consumers' surplus ("excess profits") should be captured through profit taxation. In practice, this approach is complicated by uncertainties affecting reserve size and the growth
rate of the market. However, a first step is to focus on determining the
opportunity cost of gas under assumed conditions of known (or predictable)
supply and demand.

The Meaning of Opportunity Cost

1.47 The opportunity cost for gas, or any other commodity, can be thought of as the price that will equate demand and supply. If the good is internationally traded, then the relevant import supply and export demand functions must be included in the calculations. An example of this situation is shown in Figure 6. If the good is not traded, its demand and supply curves would be those labeled "Domestic Demand" and "Domestic Supply". Its opportunity cost to the country would be $P_{NT}$ and the appropriate quantity to produce would be $Q_{NT}$. Once there is an international market for the good, however, the relevant demand and supply curves must take into account the import and export possibilities. If the good can be imported at a price $P_m$ and exported at $P_e$ (where the difference between $P_m$ and $P_e$ represents the freight, insurance and handling cost of trade), then the relevant demand and supply curves become the linked one labeled "Traded Supply" and "Traded Demand". Their intersection is at the price $P_e$ where the quantity $Q_p$ will be produced, $Q_e$ will be consumed and the difference $(Q_p - Q_e)$ will be exported. In this case, the availability of an international market means

![Figure 6. Supply and Demand for Traded and Non-Traded Goods](image-url)
both that more should be produced and also that a higher price should be charged to domestic consumers than if there were no export market for the good. The net gain to the country from producing and exporting the amount \( Q_p - Q_e \) is greater than the net loss to the country of producing and consuming only \( Q_n \) at the lower price.

1.48 This simplified diagram demonstrates the importance of the tradable/non-tradable distinction in determining opportunity costs. Natural gas, of course, is generally not a commodity that is directly traded by developing countries. However, the distinction is still relevant as long as the gas is used domestically to substitute for another commodity (such as fuel oil) that is tradable. Gas only becomes non-tradable in the economic sense when, at the margin, additional supplies that could be produced can no longer find any local markets where they would be replacing traded goods. Gas pricing linked to value of alternative petroleum fuels internationally traded viz. fuel oil, diesel oil is a desirable goal and could be considered as an upper bound for gas pricing.

**Long-Run Marginal Cost Principle**

1.49 Following gas discovery, the immediate concern in many countries has been whether or not the gas is exportable; the domestic market has often not been explored. In developing countries generally natural gas development to meet domestic demand has been slow. The major reasons include lack of strong institutional framework to integrate the activities of production, transmission, and distribution companies and consumers. Exploration and development have also been delayed due to the lack of a pricing agreement with producers. Moreover, the analysis of gas supply, demand, and delivery costs to domestic markets in developing countries has been limited. Countries have only recently begun to appreciate that natural gas can be supplied to domestic markets at a low cost that competes with other fuels.

1.50 Since gas is not directly tradable in many countries and it could be used in the domestic market either as a substitute of imported fuel and/or for new uses, it may need to be priced on the principle of the Long-Run Marginal Cost (LRMC) that could be below the opportunity cost of alternative fuels.

1.51 Marginal cost theory dates back to Hotelling and Dupuit. In the 1950s, Boiteux also worked on the development of the theory especially for application in the electric power sector. The theory has also been widely applied by other public utilities such as water, and telecommunications to set prices for their services. It provides a framework to analyze system costs and set prices for natural gas which shares many characteristics of public utilities. To meet the criteria of economic efficiency, the delivered price of natural gas should not be less than its marginal economic cost of supply. The pricing of gas, however, requires extensions to the LRMC to allow for the exhaustible nature of natural gas and meet financial cost coverage, and income distribution objectives. They can also be used for interfuel cost comparisons to decide whether it is economic to develop natural gas. The LRMC approach is therefore an explicit framework for investment decisions regarding natural gas supply.
Estimation of Marginal Cost: Methodology:

Technical Characteristics of Natural Gas Production and Transport

1.52 Natural gas shares many characteristics of public utilities, e.g. power, water, and telecommunications, such as (i) economies of scale, (ii) lumpy and indivisible capital investments, (iii) need for excess capacity to meet peak demand, reliability standards and future growth in demand, and (iv) diversity and variability of demand. Therefore, the initial capacity for production and transport is both large and long lived, and often designed to meet the growth in demand over a 10 to 20 year period. The measure of costs pertinent to supplying an incremental volume of gas is its long-run marginal cost, namely the change in total costs over the whole production period as a consequence of a small addition in supply.

1.53 The rationale for the use of long-run marginal costs (LRMC) is well established and has been widely employed for the evaluation of World Bank water, telecommunications, and power projects. The LRMC of gas is useful in negotiating prices with producers and transmission companies and consumers. It can be compared with alternative fuel costs to decide whether it is economic to develop and use gas. It can also be used to assess the appropriateness of investments in gas system expansion given projected market demand. It is consequently a determinant of actual supply of natural gas. LRMC is also useful in inter-sectoral planning and provides a benchmark by which other social and economic objectives may be evaluated.

Characteristics of Natural Gas Marginal Costs

1.54 In the abstract, LRMC is the incremental cost of optimum adjustments in the gas system expansion plan and gas system operations to meet small increments of demand. This approach estimates marginal costs of serving different consumers at different times in various regions. In practice one of the greatest sources of difficulty in the analysis of gas costs is that the technology and natural gas development and transport is subject to economies of scale and requires large and indivisible investments. Investments in gas infrastructure, following from the technology of gas recovery coupled with prevailing legal arrangements, are incurred at discrete stages. Costs of initial field development such as drilling and equipping gas fields, gas processing facilities, and main transmission lines are a high proportion of the overall lifetime costs.

1.55 A gas supply system can be divided into four interrelated stages (Figure 7). First, exploration which established the level of proven reserves and their commerciality. Exploration costs include an estimate of the finding cost of natural gas\(^1\). Second, the development and production stage requires large indivisible investments for development drilling, field preparation, field gathering, compression, separation of natural gas liquids and treatment of gas to produce pipeline quality gas to meet contract volume, quality and pressure requirements. The third stage is the transmission of gas

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1/ They exclude a depletion allowance for the value of the exhaustible resource.
from the field or gas treatment plant to the city gate. Investments in transmission facilities are lumpy and costs subject to significant economies of scale until the maximum capacity of pipelines is reached. The fourth stage is distribution to end users.

Figure 7. An Illustrative Schedule of Activities and Cashflow

1.56 Production of the first increment of gas thus requires a large initial expenditure in exploration, development, and transmission. Production of additional volumes necessitates little additional expenditure until maximum capacity is reached. Thereafter indivisibilities and diminishing returns in providing gas to meet demand lead to additional discrete and discontinuous
investments and raise the marginal costs (Figure 8). The characteristics of investment in natural gas development and transport for a given field imply that the marginal cost curve falls sharply for relatively low volumes of recovery and rises as cumulative production increases to over 60 percent of estimated recoverable reserves.

![Graph showing gas production costs](image)

**Figure 8. Gas Production Costs**

Due to the capital indivisibilities, costs will be marginal at some time and non-marginal or discontinuous at others as illustrated in Figure 9. Let us begin with the demand curve $D_1$, if production from a given gas field is below maximum capacity, the only costs immediately attributable to additional consumption are the incremental operating and maintenance costs, i.e. short-shifts, gas system expansion requires drilling in existing and new fields, new gathering and perhaps pipeline facilities as well as additional operating and maintenance costs. The resulting large cost fluctuations could cause price changes over time that would not be acceptable to consumers. Therefore, a definition of long-run marginal costs that fits the structure of investments in gas development and transport is required; costs must be estimated within a sufficiently long-run framework to incorporate the investment process.
The Average Incremental Cost (AIC) Concept

1.58 The average incremental cost (AIC) definition of marginal cost seems best suited to natural gas technology. The AIC smooths out the indivisibilities in expenditures. It also reflects the general level and trend of future costs which will have to be incurred as gas consumption increases. The AIC takes a longer view of costs and looks beyond the next increment in capacity. This is particularly important since many developing countries are at an early stage of gas development and expect a large potential shift in demand for gas.

1.59 The AIC is estimated by discounting all incremental costs that will be incurred in future to provide and maintain the estimated amount of gas which will be supplied over a specified period and dividing it by the discounted volume of incremental output over this time. The timestream of
expenditure for providing, maintaining, and running the system corresponds to a set of outputs over time:

\[
AIC_o = \sum_{t=1}^{T} \left[ I_t + (R_t - R_o) \right] / (1 + i)^t
\]

\[
= \sum_{t=1}^{T} \frac{(Q_t - Q_o)}{(1 + i)^t}
\]

I_t - capital costs in year \( t \)
Q_t - natural gas production in year \( t \) resulting from the investment
R_t - operating and maintenance costs in year \( t \)
i - opportunity cost of capital
T - time horizon for development of the project as well as a 20 year production life (t=0 is the base year).

1.60 To determine the marginal cost of supplying gas the economist must work closely with engineers and follow an iterative process. They must first agree upon the production profile in the denominator based on demand forecasts and supply potential in order to plan the least cost investment plan.

1.61 The second crucial question is what system of expansion should be designed to deliver gas to the consumer at the least possible cost. The numerator is the present value of the least cost investment stream as well as incremental operating and maintenance costs necessary first to start production and, later, to raise production up to capacity and maintain it at that level. This least cost expansion plan to meet projected demand forecasts is determined assuming a target level of system reliability. Once the price of gas is determined and the gas system begins to operate actual consumption may be different from demand estimates and consequently the costs will have to be revised.

1.62 The AIC, however, is only one of the criteria used to determine the price of natural gas. The appropriate pricing strategy for natural gas must allow for distortions due to externalities, taxes, monopoly practices, duties and subsidies as well as the objectives of financial viability and income distribution. It must also be adjusted because gas is an exhaustible resource and therefore has a depletion value that should be taken into account in its pricing.

1/ For producing fields with a declining production profile the formula has to be adjusted so as to estimate the incremental production due to the investment as the difference between the two production profiles with and without the investment \( (Q_t - Q_o) \), where \( Q_o \) is the production without the investment; the operating and maintenance costs should be also similarly adjusted.
Marginal economic cost of supply provides a lower boundary to prices. In countries with a large gas surplus, prices would be close to the marginal cost while in gas deficit countries, prices would include a larger depletion allowance. The gas transmission and distribution services are similar to other utility services where use of marginal costs in pricing is prevalent.

Summing up: Three basic principles can be used to delineate the appropriate range of gas prices. First, the upper limit of delivered prices should be set equal to the economic costs (at shadow prices) of the next best alternative fuel delivered to the particular user. Second, gas should not be sold at a delivered price lower than its full marginal economic cost of supply. Third, revenue flows to both gas producing and supplying companies or agencies should be high enough to cover their full accounting costs, including depreciation and sufficient return on capital to keep them financially viable.

These principles set forth price ranges, but do not determine specific prices per se. They help in setting the outer bounds which are basically determined by the opportunity cost of alternative resource uses and availabilities and the principles of financial and economic viability. As applied to natural gas pricing, these pricing principles provide a viable approach in the sense of ensuring that the benefits of expenditures in the sector exceed the costs.

Reliability should itself be ideally treated as a variable to be optimized; this is achieved when the marginal cost of adding capacity to improve reliability are equal to the expected value of the cost of savings to consumers resulting from gas shortages averted by these capacity increments.
Electric Power Pricing Policy

A. Introduction

2.1 Pricing and investment decisions in the electric power industry, as in other industries, have to be made in the context of uncertainty; limited or no information on some matters; distortions in the pricing system; technical feasibility; imperfect institutions; a need, with regard to prices, for simplicity and clarity; and generally a number of constraints from political, financial and equity objectives. The economist, in deciding which prices and investments are efficient, no less than the engineers and financial analysts in their work, has to consider these factors if recommendations are to be useful.

2.2 The experience of our borrowers has shown that poor investment decisions, e.g. excess or shortages of capacity, sub-optimal plant mix, can take many years to recover from, because of the long lead times to build plant needed to restore the balance, or the time required for demand to increase to the extent to justify new plant additions. A classic case of power system disequilibrium arises when tariffs are too low and demand is consequently stimulated. Because of low tariffs internal cash generation is insufficient to finance new investment. Projects are delayed through lack of finance or because demand is growing faster than the capability of the utility to implement capacity additions. Potential capacity shortages lead to low capital cost, high fuel cost plant (e.g. gas turbines) being installed, which aggravates the imbalance in the system and promotes higher imports (or reduced exports) of petroleum. Chronic shortages of finance make the utility more dependent on government support, which usually leads to lack of autonomy, government interference in day to day affairs and further loss of efficiency. The poor financial performance of the sector may lead to wages and salaries that are inadequate to attract and motivate skilled staff. Such tendencies tend to reinforce each other in a downward spiral that eventually impacts on the wider economy, e.g. the government budget, balance of payments, or lost output due to power shortages, resulting in painful adjustment process.

2.3 The needs for adjusting the economies place a greater emphasis on achieving efficiency in the electric power subsector. Energy prices that reflect economic costs are an essential part of a policy to achieve efficiency in the consumption of energy. Prices that communicate the cost of changes in consumption give incentives to consumers to adopt a level and pattern of consumption for which they are prepared to pay and mobilize resources to finance new investment. Sound investment decisions ensure that this demand is met at least cost such that the cost to the economy of capital, fuel and labor inputs to electricity production are minimized. Although the priority today is efficiency, this does not mean that considerations of equity are irrelevant. Careful tariff design (e.g. increasing block or "lifeline" tariffs) and a balance in project selection (e.g. a rural electrification component to the investment program) can enable governments to ensure that the living standards of the poor can rise without significant loss of efficiency.

Requirements of a Power Tariff

2.4 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 certain category of consumers 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. 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.

2.5 In the context of developing countries, where the perspective is that of the national economy, a pricing framework should try to meet these requirements. Since the objectives of economic efficiency, income redistribution and achieving the financial obligations of the power utility are often in conflict with one another while working out a pricing framework, it is normal to start with the efficiency objective. The Long-Run Marginal Cost (LRMC) approach to price setting has both the analytical rigor and inherent flexibility to provide a tariff structure which is responsive to the basic objectives and requirements of price setting described above.

B. Long-Run Marginal Cost (LRMC) Based Tariffs

2.6 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.

2.7 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.

2.8 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 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.

2.9 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.

2.10 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.

Marginal Costs and Power System Disequilibrium

2.11 The increased energy prices of the 1970's have resulted in power systems that are markedly different than if those who planned them had seen the future with certainty. Firstly, the plant mix - the relative proportions of fuel types and base load and peaking plant - is far from optimal in most power systems. This is a consequence of actual fuel prices differing substantially from the planners' expectations. The high sunk costs embedded in inherited capacity and long lead times for the plant needed to substitute for oil (e.g. coal, hydro and nuclear) have reduced the flexibility to respond to higher energy prices. Typically, power systems have a higher proportion of oil fired plant than would have been justified at current fuel prices.

2.12 Secondly, higher international energy prices contributed to a decrease in the rate of economic growth. Industries that were no longer viable at the new energy prices went into relative decline. These industries tended to be both energy and electricity intensive. Together with the impact of higher electricity prices, the result was an unanticipated slowdown in the growth of electricity consumption. In some countries this resulted in temporary excess capacity for electricity generation. Elsewhere, shortages in electricity supply arose from the financing problems precipitated by the impact of energy price increases on the economy, together with insufficient resource mobilization and stimulation to demand resulting from electricity tariffs that were too low. In some countries there were blackouts and load shedding through the reduction of frequency and voltage. In addition, delays
in implementing the long lead time projects needed to adjust to higher oil prices frequently led to over-investment in gas turbines.

Use of Generation Planning Models to Estimate Marginal Costs

2.13 Theoretical studies to derive marginal cost pricing and optimal investment rules have used models of electricity supply costs that are rarely used in the planning of real systems\(^1\). For estimating system marginal costs little use has been made on the mathematical programming models used by engineers for making investment decisions. However, writings of Turvey (1968, 1969, 1971) and Munasinghe and Warford (1982) describe marginal capacity costs in a system planning context, although their empirical work has relied on cruder estimates of LRMC (Munasinghe and Warford, 1982, Turvey and Anderson, 1977). Scherer (1977) used an adaptation of a linear programming model to estimate marginal costs. However, linear programming investment planning models are incapable of accurately modelling system operation and do not give a good representation of the power systems, where investments tend to be large and lumpy.

2.14 A methodology for estimating marginal capacity costs using WASP\(^2\) overcomes some of the fundamental limiting of more traditional approaches. A realistic approach to peak load pricing should take account of: (a) the diverse production technology; (b) periodic demand subject to random fluctuations; (c) the marginal outage costs incurred in not meeting demand; (d) uncertainty in supply (forced outages); (e) lumpiness in investment; (f) constraints to adjusting capacity (plant lead times); and (g) system disequilibrium (imbalance between supply and demand, or sub-optimal plant mix) and its implications for marginal cost changing over time. An operational methodology for estimating the LRMC of generation using WASP that takes account of these aspects of the real world is described below.

A Methodology for Calculating LRMC: Overview

2.15 The methodology for calculating LRMC proposed below follows the traditional approach insofar as LRMC is considered to have two components: (a) marginal capacity cost, the cost of expanding capacity to meet incremental demand, usually expressed in $/kW or $/kW/a; and (b) marginal energy cost, consisting of fuel and variable operating and maintenance costs, usually expressed in $/MWh.

2.16 The methodology follows recent theoretical work in that marginal capacity costs are allocated to off-peak periods. Indeed, the traditional distinction of "peak" and "off-peak" is artificial in a world of uncertainty. Through a combination of plant failures and demand uncertainty there is a finite probability of demand being curtailed at any time of the day and year. With capacity subject to random failure, demand characteristics alone do not indicate when the system is at stress.

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1/ Examples of such studies are those by Balasko (1975), Crew & Kleindonfer (1976) and Williamson (1966).
2/ Wien Automatic System Planning package.
The Consequences of an Increase in Demand

2.17 In order to illustrate the proposed methodology, let us consider the costs to society of an increase in demand. Since the purpose of the methodology is to estimate the long-run marginal cost, let us consider an increase in demand related to the acquisition of new electricity consuming equipment by a consumer. The consequent demand increase will therefore be sustained over a period of years related to the life of the equipment. For the first 2 to 3 years the actions which most utilities can take are limited, since the shortest lead time for generating plant is typically 2 to 3 years for a gas turbine. The immediate consequence of an increment in demand is usually an increase in the amount of unserved energy. Other short-term responses are possible. Some utilities have the option of increasing electricity imports. In other cases it may be possible to defer the retirement of old plant.

2.18 After the initial 2 to 3 years following an increase in demand an adjustment to the least cost investment program is technically feasible. In a balanced system with optimal plant mix and reserve margin optimal before the increase in demand, the response to an increase in demand would probably be the addition of an additional peaking unit, e.g. a gas turbine. However, if there is excess capacity, there may be sufficient time to advance a base load plant. In such a case, fuel savings would offset part of the capital cost. The net cost would be less than the cost of commissioning a gas turbine, otherwise the rational decision would have been not to advance the base load plants, but to install a gas turbine.

2.19 After the adjustment to the least cost investment program a later adjustment may be required to restore the optimal plant mix. For example, the optimal plant mix - the ratio between peaking and base load capacity - would be upset if a gas turbine were advanced to meet the incremental demand, when base load capacity would have been required but could not be advanced because of its lead time. To restore the optimal plant mix the least cost next investment might then be base load plant instead of peaking plant. The adjustment to the least cost program might be a chain of modifications to the phasing of investments rather than the simple addition of a gas turbine, or the bringing forward of the entire investment program.

Definition of Marginal Capacity Cost

2.20 The foregoing suggests that the response to an increment in demand may be far from simple. A sufficiently broad definition of the marginal capacity cost has been used in this paper to encompass any response unique to a particular power system. The long-run marginal cost of capacity is defined as the costs to society of the actions taken by the power utility to meet a sustained increase in demand. Apart from externalities (e.g. incremental pollution) which are rarely considered directly in the calculation of LRMC, the costs of an increase in demand are the incremental capacity costs, net of fuel savings, incurred by the utility, plus the cost of incremental outages incurred by consumers.

2.21 A corresponding definition can be arrived at for a decrease in demand. In such a case the cost of the unserved energy would be lower. The supply response could be different, i.e. it is easier to delay long lead time
plant than to bring it forward, so that the costs of gas turbines are less likely to figure in the calculation of the long-run marginal cost of generating capacity. Indeed, in many cases it would be better to base the calculation of LRMC on an incremental decrease in demand since demand forecasts are usually too high rather than too low.

2.22 Note that this definition applies only to marginal capacity costs. The total LRMC also includes marginal energy (fuel) costs, the calculation of which is discussed later. However, in some circumstances, e.g. when a total LRMC is needed to evaluate small investments, the approach described below can be modified to calculate a total LRMC that includes both capacity and fuel costs.

Principles for Calculating LRMC of Generating Capacity

2.23 The basis of the methodology is to first prepare a least cost generation investment program, and then second, reoptimize the investment program with a sustained increase in demand added to (or subtracted from) the demand projections. This reoptimization should take account of technical constraints imposed by plant lead times and construction schedules. In the case studies attached to this paper WASP III was used to prepare the basic data for the calculation of LRMC. However, the WASP model is not essential to the methodology. Other optimization models could be used. Indeed, in small power systems, or when investment opportunities are limited, a good simulation model could be sufficient. However, since changes in unserved energy are an essential part of the short-term consequences on increment in demand, the optimization or simulation model should have a probabilistic model of system operation.

Calculation of Marginal Capacity Cost

2.24 The components of marginal capacity cost consist of the following: (a) incremental capital costs; (b) incremental fixed operating and maintenance (O&M) costs; (c) incremental unserved energy; and (d) fuel savings. The calculation of each of these is described below.

2.25 The capacity cost element of marginal capacity cost is straightforward to calculate. The present values of the stream of capital cost cash flows for the base and incremental loads optimizations are subtracted to yield the incremental costs, annuitized over the life of the plant to obtain the equivalent annual cost and then divided by the incremental demand. The costs are annuitized because a cost/kW/a is required for tariff design, not a cost/kW.

1/ A total LRMC ($/MWh) can be calculated by dividing the present value of incremental capital, operating and fuel costs (i.e. the difference between these costs in the Base and Incremental Loads optimization) by the present value of incremental energy.

2/ The annuity factor $A$ is the annual expenditure over $n$ years, which has a present value of $1$ at discount rate $r$ i.e.

$$A = \frac{r}{1 - (1+r)^{-n}}$$

e.g. if the discount rate is 0.10 (10%) and the plant life 30 years, then $A = 0.10608$. 

1.
2.26 Similarly, to calculate the **fixed O&M component** the annual increments in the stream of fixed O&M costs are first calculated for the base and advanced load cases. Annual increments in the stream of accumulating O&M costs are taken so that the contribution to LRMC will be a cost/kW/a. The streams of annual O&M cost increments are then present valued and divided by the incremental demand.

2.27 The **unserved energy** component is calculated first as the difference in present value unserved energy costs between the incremental and base cases, divided by the incremental demand. This is the total incremental unserved energy cost over the period of LRMC analysis, e.g. a cost/kW. To calculate the equivalent annual cost, the cost/kW of unserved energy should be annuitized over the period of LRMC analysis.

**Fuel Savings**

2.28 Advancing base load plant to meet an increment in demand results in the fuel cost of meeting incremental demand being lower than if incremental demand had been met by a peaking unit, e.g. a gas turbine. If the system is in disequilibrium, i.e. has a sub-optimally high proportion of high fuel cost plant, an increase in demand would speed up the adjustment to an optimal plant mix. Accelerating this adjustment would, in most cases, lower the average fuel cost of supplying all consumers. Fuel savings can be estimated using the following procedure:

(a) after WASP had produced a revised least cost investment program to meet an increment in demand, the fuel costs of the advanced program can be re-estimated using the original base case demand forecast;

(b) the fuel saving should be calculated as the fuel cost with the base case investment program and base case demand forecast, minus the fuel cost with the advanced investment program and base case demand forecast;

(c) this fuel saving should be expressed as a cost/kW by dividing by the increment of demand; and

(d) an annual incremental fuel saving ($/kW/a) to be estimated by annuitizing the fuel saving per kW over the period of the analysis.

This approach enables the impact on system fuel costs of changing the investment program to be separated from the effect of changing demand.

**Marginal Energy Costs**

2.29 Conceptually, the calculations of marginal energy costs is more straightforward, especially since marginal energy cost (more commonly marginal fuel cost, excluding marginal variable O&M costs) is the basis for dispatching generating plant. In principle, marginal energy costs can be calculated using the models used for on-line system operation or off-line operations planning. Nevertheless, some estimation problems arise from: (a) the difference between the marginal fuel cost of changing the output of a thermal plant already operating and bringing the unit from hot reserve into operation - the "no load" fuel consumption; (b) the fuel for off-load heat involved in removing a
unit from service during the low load period and keeping it warm; and
(c) establishing the incremental fuel required for incremental electricity
output from a dual purpose unit, e.g. combined heat and power or
desalination. These difficulties can be overcome by postulating an increment
in demand of say 2% and letting the operations planning model establish the
incremental energy cost with other outputs, e.g. pass-out steam to
desalination plants, held constant.

2.30 A procedure for calculating marginal energy costs and the loss of
load probabilities (LOLP's) used to allocate marginal capacity costs to each
period would involve the following steps:

(a) simulate the monthly operation of the system for one year to
determine: (i) the plant down for maintenance; and (ii) the monthly
LOLP used to assign the annual marginal capacity cost (cost/kW/a) to
monthly charges (cost/kW/month);

(b) simulate hour by hour system operation for typical days each month
(preferably every day) excluding plant down for maintenance. This
simulation would also produce the hour by hour LOLP's useful for
transforming the monthly marginal capacity costs to a cost/kWh by
time of day; and

(c) re-simulate system operation for the typical days with demand changed
by about 2%. The marginal energy cost is then calculated as the
difference between the fuel costs in the hour, divided by the
incremental generation.

2.31 WASP is not suitable for estimating marginal energy costs since an
hour by hour simulation is required to give the marginal costs by time of day
needed for tariff design. A computer program RELCOMP can be used to estimate
marginal energy costs and period LOLP's.

Peak Responsibility

2.32 All time periods contribute some likelihood of failure to the annual
LOLP. That is, there is a finite probability that the full load will not be
met during any specified time period of the year because of random forced
outages, maintenance outages, and hydro unavailability. Therefore, all time
periods, including off-peak periods, should be responsible for some portion of
the capacity costs. In particular, these capacity costs can be assigned to
the various time periods in proportion to their contribution to the annual
LOLP.

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

Practical Tariff Setting

2.34 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, consumers could indicate their willingness to pay for
more consumption, thus signalling the justification of further investment to
expand capacity.
2.35 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 surpluses can be used to finance the sector investment program. 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.

2.36 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.

2.37 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 require 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-peak); and (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.

Summary

2.38 To summarize, in the first stage of calculating LRMC, the economic (first best) efficiency objectives of tariff setting are satisfied, because
the method of calculations 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.

2.39 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. over-investment, 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.

2.40 Finally, any LRMC based tariff is a compromise between many different objectives. Therefore, there is no "ideal" tariff. Reconciling the objectives of economic efficiency, financing viability and equity is the art of tariff design. By using the LRMC approach, it is possible to revise and improve the tariff on a consistent and on-going basis, and thereby approach the optimum price, without subjecting long-standing consumers to "unfair" shocks, in the form of large abrupt price changes.
C. CASE STUDIES

Case Study - Country A

Characteristics of the Power System

1. The power system in Country A is characterized by excess capacity caused by premature investment in oil fired steam plant and projected demand failing to materialize. A new oil fired steam plant is under construction so that the reserve margin will increase to about 105% in 1988, compared to an optimum of about 30% (Table 1).

2. A further feature of the system is its dependence on imported oil as a primary energy source. Recent developments in the international coal market and the prospects for hydro have meant that cheaper options now exist for power generation. The system is, therefore, characterized first by a plant mix that is suboptimal with respect to present fuel prices (excess of oil-fired generation); and second, the excess generating capacity that will prevail in the system up to 1995. Fortunately demand should increase at about 7.8% p.a. during the period 1985-95 so that generating capacity would be in equilibrium with demand in about 10 years. The present suboptimal plant mix strongly influences the choice of investments aimed at reducing systems fuel costs. The least-cost investment program contains hydro units and imported coal-fired base load plants (Table 1).
<table>
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<tr>
<th>Year</th>
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<th>Oil-Fired</th>
<th>Hydro</th>
<th>Coal</th>
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</table>

Notes:

/1 Capacity shown is available at the beginning of the year.
/2 Loss of load probability after allowing for scheduled maintenance.
Calculation of Marginal Capacity Cost

3. The marginal capacity cost of generation was estimated by using the WASP program to reoptimize the least-cost investment program with a 35-MW increment in demand, equivalent to about one year's growth in demand. The response to the 35-MW load increment was: (a) increased unserved energy; (b) bringing forward of run of river hydro and coal-fired units by one year; and (c) additional coal-fired units in later years. In the Advanced Case, the hydro units were selected by the program in preference to advancing a gas turbine mainly because of the fuel savings that the hydro units introduce in a suboptimal system.

4. To study how marginal costs change over time as the system approaches equilibrium, marginal capacity costs were calculated for six base years 1985-1990. Since the construction of the hydro station would take about 5 years, the advanced case was used to estimate LRMC up to year 1987 inclusive. Assuming a 10-year life of electrical assets acquired by consumers in Country A, the changes in LRMC over the period 1985-1987 as the system approaches equilibrium were investigated using this Advanced Case least-cost program. However, in 1988 it would be technically impossible to advance the hydro units and therefore the Base Case was reoptimized again. The resulting program (Advanced Case B) was used to investigate changes in LRMC up to 1990 inclusive. The Advanced Case B showed a reordering of the plant program resulting in: (a) a gas turbine in 1992; and (c) advancing the coal units by one year. Table 2 shows the optimization results and Figure 1 shows the base and advanced programs.

**FIGURE 1**

**COUNTRY A**

PEAK LOAD AND TOTAL CAPACITY
1983 - 2010

![Graph showing peak load and total capacity from 1983 to 2010](image)
Calculation of Marginal Capacity Cost

5. The marginal capacity cost of generation was estimated by using the WASP program to reoptimize the least-cost investment program with a 35-MW increment in demand, equivalent to about one year's growth in demand. The response to the 35-MW load increment was: (a) increased unserved energy; (b) bringing forward of run of river hydro and coal-fired units by one year; and (c) additional coal-fired units in later years. In the Advanced Case, the hydro units were selected by the program in preference to advancing a gas turbine mainly because of the fuel savings that the hydro units introduce in a suboptimal system.

6. To study how marginal costs change over time as the system approaches equilibrium, marginal capacity costs were calculated for six base years 1985-1990. Since the construction of the hydro station would take about 5 years, the advanced case was used to estimate LRMC up to year 1987 inclusive. Assuming a 10-year life of electrical assets acquired by consumers in Country A, the changes in LRMC over the period 1985-1987 as the system approaches equilibrium were investigated using this Advanced Case least-cost program. However, in 1988 it would be technically impossible to advance the hydro units and therefore the Base Case was reoptimized again. The resulting program (Advanced Case B) was used to investigate changes in LRMC up to 1990 inclusive. The Advanced Case B showed a reordering of the plant program resulting in: (a) a gas turbine in 1992; and (c) advancing the coal units by one year. Table 2 shows the optimization results and Figure 1 shows the base and advanced programs.

FIGURE 1

COUNTRY A
PEAK LOAD AND TOTAL CAPACITY
1983 - 2010
Table 2
Country A

Generation Investment Programs used to Calculate LRMCs

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7. The cash flows used to calculate the LRMC are shown in Annex 2. The LRMC of generating capacity was found to consist mainly of capital costs, which were offset to a large extent by fuel savings (Table 3). Variations in the capital cost component of the marginal capacity cost were caused by the lumpiness of investment. In particular, the decline in the marginal capacity

Table 3
Country A

LRMC of Generating Capacity
(US$/kW/a, 1984 prices)

<table>
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<tr>
<th>Year</th>
<th>Capital</th>
<th>Fixed O &amp; M</th>
<th>Unserved Energy</th>
<th>Fuel Savings</th>
<th>Total</th>
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<td>15.1</td>
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<td>42.2</td>
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cost in 1986 was a consequence of the first coal unit entering the 10 year timeslice for both the base and advanced cases. Fuel savings increased rapidly as the commissioning date of the low energy cost hydro plant was approached. Once this plant has become committed (sunk), fuel savings are smaller as they are based on the cost of bringing forward a coal fired plant, which has higher energy costs than the hydro plant. These fuel savings decline as the equilibrium plant mix is approached. The cost of unserved energy in the marginal capacity cost increases as equilibrium between demand and available supply is approached. These figures indicate that capital costs and fuel savings are the dominant factors in the marginal capacity cost, which shows an upward trend as the excess capacity is eliminated and the plant mix improved (Figure 2).

Peak Responsibility

The estimation of peak responsibility as a measure of the relative need for generating capacity for different time periods was estimated according to the time period's contribution to the annual expected unserved energy, using the RELCOMP model. The results indicate that about 94% of the marginal capacity costs should be allocated to the peak hours of 1800 to 2200 inclusive and the remaining 6% to the off-peak hours. There is also significant seasonal variation in the allocation of capacity marginal costs. About 41% of capacity marginal costs should be allocated to the Autumn (fall) season, and only 5% to the winter season. Figure 3 illustrates the results.
FIGURE 3

HOURLY CAPACITY RESPONSIBILITY CURVE - 1965

HOURLY CAPACITY RESPONSIBILITY CURVE - 1988
Marginal Energy Costs

9. Marginal energy costs were calculated for typical day each in January, April, July, and October as representation of the seasons, Winter, Spring, Summer and Autumn (Fall), using hourly load data for each of the typical days. The BELCOMP computer program was used to calculate the system's variable costs for a base case and for a 3% increment in hourly demand. The difference in systems variable costs between the base and increased load cases were used in calculating the systems marginal energy costs.

10. The results shown in Figure 4 indicate that on the whole there is very little seasonal variation in marginal energy costs, however, peak-period energy costs are about 14% above the off-peak period energy costs. Almost all the expected marginal energy costs are accounted for by the oil-fired steam plants.

FIGURE 4
COUNTRY A
Short Run Marginal Energy Cost by Time of Day
Season - 1985
Total LRMC

11. The total marginal cost at the generation level is the sum of capacity marginal cost and the marginal energy cost. At the level of generation, this is estimated for 1986 to be $75.97/MWh and $80.68/MWh for 1990. Although the LRMC of generating capacity shows an increase of 38% between 1986 and 1990, total marginal cost increases by only about 6%. Marginal energy costs show very little variation between 1986 and 1990 and dominate the total marginal costs. Nevertheless, the 6% real increase in LRMC over 4 years is still significant. Moreover, the total LRMC using the proposed methodology for calculating marginal capacity costs is as much as 25% lower than when other methodologies in common use, e.g. using the LRAIC approach the total LRMC would be $95.4/MWh, compared to $75.9/MWh.

Case Study - Country B

System Characteristics

12. The Country B system is characterized by first, a plant mix that is suboptimal with respect to present fuel prices (excessive oil/natural gas capacity); and second, the commissioning of a nuclear power station will result in excess capacity until about 1993 (Figure 5). This temporary excess capacity means that an increase in system peak demand has no effect on generating capacity until the mid 1990's. Until about 1995, the principal effect of an increment in demand is a decrease in system reliability, which results in higher unserved energy costs. In addition there would be higher fuel costs, but these are not included in the marginal capacity cost.

13. The present suboptimal plant mix strongly influences the choice of new investment. The least cost expansion program contains mainly coal fired base load plant, although one 100 MW gas turbine is shown in the program up to the end of the century.

Calculation of Generation Marginal Capacity Cost

14. The marginal capacity cost of generation was estimated by using the WASP program to reoptimize the least cost program with a 200 MW increment in demand, equivalent to about one year's growth in demand. The consequence of this increment in demand which began in 1984, was to bring forward a 250 MW coal unit from 1995 to 1994 (Table 4). Although the program could have chosen to advance a gas turbine, the base load unit was preferred, probably because of the fuel savings it introduced to the suboptimal system. Because the lead time of a coal unit is about 5 years, this advanced case program was able to be used to calculate the marginal capacity costs for a sustained increment in demand commencing in the years 1985 to 1989 inclusive. These calculations enabled the change in marginal capacity cost over time to be investigated as the system returns towards equilibrium plant mix and supply demand balance.
FIGURE 5

Table 6

Country B

Generation Investment Programs Used to Calculate LRMC's

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<td>GT 1</td>
<td>Coal A 1</td>
<td>Coal A 2</td>
</tr>
<tr>
<td></td>
<td>GT 1</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>1996</td>
<td>Coal A 2</td>
<td>Coal A 2,3</td>
<td>Coal A 2,3</td>
<td>Coal A 2</td>
</tr>
<tr>
<td>1997</td>
<td>Coal A 3</td>
<td>Coal A 4,5</td>
<td>Coal A 4,5</td>
<td>Coal A 3,4</td>
</tr>
<tr>
<td>1998</td>
<td>Coal A 4,5</td>
<td>Coal A 6</td>
<td>Coal A 6</td>
<td>Coal A 5,6</td>
</tr>
<tr>
<td>1999</td>
<td>Coal A 6</td>
<td>GT 2</td>
<td>Coal A 7</td>
<td>Coal A 7</td>
</tr>
<tr>
<td></td>
<td>GT 2</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2000</td>
<td>Coal A 7,8</td>
<td>GT 3</td>
<td>Coal A 8</td>
<td>GT 3</td>
</tr>
<tr>
<td></td>
<td>GT 3</td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>2001</td>
<td>GT 2, 3</td>
<td>Coal B 1</td>
<td>Coal B 1</td>
<td>Coal B 2</td>
</tr>
</tbody>
</table>
In 1990, it would be impossible to bring forward the first coal unit scheduled for 1995, so a shorter lead time gas turbine was brought forward instead (Table 4). In 1991, neither the first nor second coal units could be brought forward so that first, a 100 MW gas turbine is brought forward from 1995 to 1994 and second, a new 100 MW gas turbine is introduced in 1995. This distorts the optimal plant mix and the 4th, 6th and 8th coal units are still brought forward to generate fuel savings. By 1999, the set of plant adjustments has been completed so that the plant configuration in the case used to calculate the 1991 LRMC is the same as for the advanced case used to calculate the 1984-1989 LRMC's. This shows that an increased in demand may produce a complex reordering of the investment program, even if the immediate impact of the increment is to bring forward or add a gas turbine to the investment program.

15. The marginal cost of generating capacity in Country B was found to consist of mainly capital costs which were offset to a large extent by fuel savings (Table 5). The capital and fixed O & M components increase steeply as the time to bring forward an investment approaches, but there is also a corresponding increase in the fuel savings from bringing forward this plant (Figure 6). As the excess capacity is eliminated the unserved energy component, valued at US$1.50/kWh, also increases from 9.1% of the marginal capacity cost in 1984 to 18.0% in 1989. These figures indicate that the marginal cost of unserved energy is not insignificant, especially when excess
capacity is nearly eliminated, and should not be excluded from the calculation of LRMC. Cash flows used to calculate the LRMC of generating capacity are shown in Annex 3.

Table 5

Country B

Summary of LRMC of Generating Capacity
(US$/kWh, constant 1983 prices)

<table>
<thead>
<tr>
<th>Year</th>
<th>Capital</th>
<th>O &amp; M</th>
<th>Unserved Energy</th>
<th>Fuel Saving</th>
<th>Total</th>
</tr>
</thead>
<tbody>
<tr>
<td>1984</td>
<td>66.46</td>
<td>10.36</td>
<td>3.72</td>
<td>-39.68</td>
<td>40.86</td>
</tr>
<tr>
<td>1985</td>
<td>74.43</td>
<td>11.61</td>
<td>4.19</td>
<td>-47.03</td>
<td>43.21</td>
</tr>
<tr>
<td>1986</td>
<td>87.75</td>
<td>13.54</td>
<td>4.72</td>
<td>-55.41</td>
<td>50.60</td>
</tr>
<tr>
<td>1987</td>
<td>94.37</td>
<td>14.94</td>
<td>5.62</td>
<td>-64.77</td>
<td>50.16</td>
</tr>
<tr>
<td>1988</td>
<td>109.60</td>
<td>16.96</td>
<td>6.06</td>
<td>-75.43</td>
<td>57.19</td>
</tr>
<tr>
<td>1989</td>
<td>111.44</td>
<td>17.01</td>
<td>8.98</td>
<td>-87.45</td>
<td>49.98</td>
</tr>
<tr>
<td>1990</td>
<td>120.43</td>
<td>18.50</td>
<td>9.47</td>
<td>-88.80</td>
<td>59.60</td>
</tr>
<tr>
<td>1991</td>
<td>130.42</td>
<td>20.67</td>
<td>9.46</td>
<td>-83.06</td>
<td>77.27</td>
</tr>
</tbody>
</table>

Marginal Energy Cost

16. The marginal energy cost was calculated for typical winter and summer days in 1985 using the RELCOMP computer program. As the lower part of Figure 7 shows, there is little variation in the marginal fuel cost by time of day and other analysis has shown that there is also little variation throughout the year. This is because: (a) hydro energy smooths most of the variation in demand; and (b) there is about 2,500 MW of oil-fired units, with almost identical operating characteristics operating at the margin and meeting incremental demand over a wide range. This is illustrated by the composition of expected marginal operating cost shown in Table 6. Almost all the expected marginal cost is accounted for by the cost of oil-fired steam plant, with a small contribution by other plant to cover for outages.

Table 6

Country B

Analysis of Marginal Energy Cost
Peak Hour 1985 - Winter Day

<table>
<thead>
<tr>
<th>Unit</th>
<th>Expected Incremental Generation (MWh)</th>
<th>Weight</th>
<th>Unit Fuel Cost/($/MWh)</th>
<th>Weighted Expected Marginal Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Steam (oil)</td>
<td>108.2</td>
<td>0.975</td>
<td>22.8</td>
<td>22.2</td>
</tr>
<tr>
<td>Steam (coal)</td>
<td>2.4</td>
<td>0.022</td>
<td>28.1</td>
<td>0.6</td>
</tr>
<tr>
<td>Gas turbine</td>
<td>0.3</td>
<td>0.003</td>
<td>97.4</td>
<td>0.3</td>
</tr>
<tr>
<td>Total</td>
<td>110.0</td>
<td>1.000</td>
<td></td>
<td>23.1</td>
</tr>
</tbody>
</table>
Total LEMC

17. The total LEMC at the generation level consists of the marginal cost of generating capacity plus the marginal energy cost. The total marginal cost for a typical bulk consumer would be $29.9/MWh in 1984 and $33.0/MWh in 1990. Marginal energy costs account for 77% of total LEMC in 1984 and 70% in 1990. Although the LEMC of generating capacity increases by 46% during the period 1984 to 1990, total LEMC increases by only 10%. At lower voltage levels, where distribution costs have to be added, the real increase in LEMC would be lower. This indicates the importance of paying attention to the estimation of marginal energy costs as well as marginal capacity costs.

Peak Responsibility

18. The results of the RELCOMP run were used to demonstrate the methodology for allocating capacity costs between peak and off-peak periods. Table 7 shows the unserved energy hour by hour on a typical winter day in 1985. The distribution of unserved energy used to weigh the capacity costs is also shown. The system is under greatest stress at 0700 h. Consequently, the highest capacity cost is allocated to 7 am. The hour by hour variation in marginal energy plus marginal capacity cost, which would be used to design a time of day tariff is also shown in Table 7 and illustrated in Figure 7.

FIGURE 7

MARGINAL COST ($/MWh)

<table>
<thead>
<tr>
<th>Hour</th>
<th>Marginal Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>01</td>
<td>0.0</td>
</tr>
<tr>
<td>02</td>
<td>0.0</td>
</tr>
<tr>
<td>03</td>
<td>0.0</td>
</tr>
<tr>
<td>04</td>
<td>0.0</td>
</tr>
<tr>
<td>05</td>
<td>0.0</td>
</tr>
<tr>
<td>06</td>
<td>0.0</td>
</tr>
<tr>
<td>07</td>
<td>29.9</td>
</tr>
<tr>
<td>08</td>
<td>33.0</td>
</tr>
<tr>
<td>09</td>
<td>33.0</td>
</tr>
<tr>
<td>10</td>
<td>33.0</td>
</tr>
<tr>
<td>11</td>
<td>33.0</td>
</tr>
<tr>
<td>12</td>
<td>33.0</td>
</tr>
<tr>
<td>13</td>
<td>33.0</td>
</tr>
<tr>
<td>14</td>
<td>33.0</td>
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<td>15</td>
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<tr>
<td>16</td>
<td>33.0</td>
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<tr>
<td>17</td>
<td>33.0</td>
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<tr>
<td>18</td>
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<td>19</td>
<td>33.0</td>
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<tr>
<td>20</td>
<td>33.0</td>
</tr>
<tr>
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<td>33.0</td>
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<tr>
<td>22</td>
<td>33.0</td>
</tr>
<tr>
<td>23</td>
<td>33.0</td>
</tr>
<tr>
<td>24</td>
<td>33.0</td>
</tr>
</tbody>
</table>

FUEL COST | TIME OF DAY | CAPACITY COST
### Table 7

**Marginal Fuel Cost and Allocation of Marginal Capacity Cost by Time of Day**

<table>
<thead>
<tr>
<th>Hour</th>
<th>Demand (MW)</th>
<th>Marginal Fuel Cost ($/MWh)</th>
<th>Observed Energy (MWh)</th>
<th>Energy (MWh)</th>
<th>Marginal Capacity Cost ($/MWh)</th>
<th>Total Marginal Cost ($/MWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>1</td>
<td>3817</td>
<td>23.06</td>
<td>0.0644</td>
<td>0.003</td>
<td>0.01</td>
<td>23.08</td>
</tr>
<tr>
<td>2</td>
<td>3870</td>
<td>23.31</td>
<td>0.0003</td>
<td>0.000</td>
<td>0.00</td>
<td>23.31</td>
</tr>
<tr>
<td>3</td>
<td>3872</td>
<td>23.56</td>
<td>0.0001</td>
<td>0.000</td>
<td>0.00</td>
<td>23.56</td>
</tr>
<tr>
<td>4</td>
<td>3872</td>
<td>23.06</td>
<td>0.0000</td>
<td>0.000</td>
<td>0.00</td>
<td>23.06</td>
</tr>
<tr>
<td>5</td>
<td>3872</td>
<td>23.31</td>
<td>0.0000</td>
<td>0.000</td>
<td>0.00</td>
<td>23.31</td>
</tr>
<tr>
<td>6</td>
<td>4362</td>
<td>23.06</td>
<td>1.4010</td>
<td>0.076</td>
<td>0.29</td>
<td>23.35</td>
</tr>
<tr>
<td>7</td>
<td>5197</td>
<td>24.56</td>
<td>885.2000</td>
<td>64.201</td>
<td>185.16</td>
<td>209.68</td>
</tr>
<tr>
<td>8</td>
<td>4957</td>
<td>24.56</td>
<td>32.4300</td>
<td>1.766</td>
<td>6.78</td>
<td>30.09</td>
</tr>
<tr>
<td>9</td>
<td>4636</td>
<td>23.56</td>
<td>0.5390</td>
<td>0.029</td>
<td>0.11</td>
<td>23.67</td>
</tr>
<tr>
<td>10</td>
<td>4777</td>
<td>23.06</td>
<td>0.0290</td>
<td>0.002</td>
<td>0.01</td>
<td>23.07</td>
</tr>
<tr>
<td>11</td>
<td>4700</td>
<td>23.31</td>
<td>0.1057</td>
<td>0.005</td>
<td>0.02</td>
<td>23.33</td>
</tr>
<tr>
<td>12</td>
<td>4619</td>
<td>22.81</td>
<td>0.7632</td>
<td>0.040</td>
<td>0.16</td>
<td>22.97</td>
</tr>
<tr>
<td>13</td>
<td>4559</td>
<td>23.80</td>
<td>0.6162</td>
<td>0.023</td>
<td>0.09</td>
<td>23.89</td>
</tr>
<tr>
<td>14</td>
<td>4531</td>
<td>24.05</td>
<td>2.7570</td>
<td>0.150</td>
<td>0.58</td>
<td>24.63</td>
</tr>
<tr>
<td>15</td>
<td>4502</td>
<td>24.37</td>
<td>0.9080</td>
<td>0.049</td>
<td>0.19</td>
<td>24.76</td>
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<tr>
<td>16</td>
<td>4662</td>
<td>24.05</td>
<td>2.9480</td>
<td>0.161</td>
<td>0.62</td>
<td>24.67</td>
</tr>
<tr>
<td>17</td>
<td>5055</td>
<td>24.30</td>
<td>46.8600</td>
<td>2.552</td>
<td>9.80</td>
<td>34.10</td>
</tr>
<tr>
<td>18</td>
<td>5295</td>
<td>23.06</td>
<td>235.6000</td>
<td>12.829</td>
<td>49.27</td>
<td>72.36</td>
</tr>
<tr>
<td>19</td>
<td>5453</td>
<td>23.31</td>
<td>375.6000</td>
<td>20.452</td>
<td>78.55</td>
<td>101.86</td>
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<tr>
<td>20</td>
<td>5222</td>
<td>23.56</td>
<td>132.4000</td>
<td>7.209</td>
<td>27.69</td>
<td>51.25</td>
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<td>21</td>
<td>4968</td>
<td>24.05</td>
<td>83.9500</td>
<td>4.571</td>
<td>17.56</td>
<td>41.61</td>
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<td>22</td>
<td>4521</td>
<td>23.56</td>
<td>31.9000</td>
<td>1.739</td>
<td>6.68</td>
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<tr>
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<td>4292</td>
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<td>2.3900</td>
<td>0.130</td>
<td>0.50</td>
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<tr>
<td>24</td>
<td>4073</td>
<td>24.30</td>
<td>0.1915</td>
<td>0.010</td>
<td>0.46</td>
<td>24.36</td>
</tr>
<tr>
<td></td>
<td>Total</td>
<td></td>
<td>1836.47101959</td>
<td>100.000</td>
<td>384.09</td>
<td></td>
</tr>
</tbody>
</table>

**D. Conclusions**

19. The findings of the case studies suggests that some of the methodologies currently used to calculate the LRMC of generating capacity should be discarded. In particular, the cost/kW of the next investment and
LBAIC of plant currently under construction approaches produced large errors in both countries. The approach based on the cost/kW of the peaking unit (gas turbine) produced mixed results. These suggest that this methodology should be used with caution and is inappropriate when the power system is in disequilibrium. The LBAIC approach produced large errors in both case studies. A comparison of the alternative methodologies for estimating the marginal capacity cost is shown in Table 8.

### Table 8

<table>
<thead>
<tr>
<th>Country A</th>
<th>Country B</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cost/kW of Gas Turbine</td>
<td></td>
</tr>
<tr>
<td>(a) adjusted by unit availability</td>
<td>109</td>
</tr>
<tr>
<td>(b) adjusted by reserve margin</td>
<td>115</td>
</tr>
<tr>
<td>(c) present value, reserve margin adj.</td>
<td>76</td>
</tr>
<tr>
<td>Cost/kW of Next Investment</td>
<td></td>
</tr>
<tr>
<td>(a) project under construction</td>
<td>290</td>
</tr>
<tr>
<td>(b) next new project</td>
<td>301</td>
</tr>
<tr>
<td>Long run Average Incremental Cost (LBAIC)</td>
<td></td>
</tr>
<tr>
<td>(a) based on current investments</td>
<td>294</td>
</tr>
<tr>
<td>(b) based on marginal investments</td>
<td>172</td>
</tr>
</tbody>
</table>

The case studies show the importance of basing the calculation of the marginal capacity cost on the actions that would be taken by a utility to adjust its capacity in response to incremental demand. Assuming that a kW of incremental demand results in a kW of gas turbine capacity in the same year is incorrect because a gas turbine cannot normally be commissioned in such a short time. Furthermore, an excess of gas turbines or oil-fired plant on the system would make further gas turbines a last resort to avoid heavy load shedding. Even if a gas turbine were justified in this case, the two case studies show that a further set of adjustments would take place in later year to restore the optimum plant mix. Crucial to identifying the options open to a utility in meeting incremental demand in the time taken to build a new plant. Plant lead times constrain which plant can be brought forward or delayed. Units already under construction may be "sunk" in the sense of it
not being economic or contractually feasible to change their commissioning
dates. Long lead times for power generating plant reduce the flexibility to
respond to unforeseen changes in demand and are a cause of temporary excess
capacity. The proposed LRMC methodology enables the tariff analyst to
recognize this constraint.

21. The case studies confirm that marginal energy costs, which comprise
mainly fuel, account for more than half of the total LRMC at the level of
generation. This result is not new, but emphasizes the need to give attention
to estimating marginal energy costs as well as marginal capacity costs. Crude
assumptions such as assuming that because a system has gas turbines they will
operate to meet an extra kWh in the peak period could lead to a massive
overestimating of marginal energy cost. As shown in Table 6, they may make a
small, but significant, contribution to marginal energy cost. This highlights
the need for a probabilistic model of system operation to enable the expected
cost of meeting incremental demand to be calculated. Furthermore,
that a good operations simulation model should recognize.

22. While the marginal capacity cost may increase steeply in real terms
as the system approaches equilibrium the predominance of fuel costs in total
LRMC means that the total LRMC may increase more slowly. In the Country B
case study the real marginal capacity cost increased at 6.5% p.a. The total
LRMC would increase at about 1.7% p.a. if oil prices remained constant. For
Country A, the marginal capacity cost would increase at 4.4% p.a. in real
terms, but total LRMC would increase at only 1.5% p.a., with constant real oil
prices during the period. The conclusion is that the real increases in
marginal capacity cost arising from system disequilibrium are too large to be
ignored, but they do not lead to an unacceptably high rate of increase in
overall tariffs.

23. As well as providing an operational method for estimating LRMC's for
tariff design, the methodology has other applications. It is suitable for
estimating the cost of generation or distribution investments, or to evaluate
the benefit of reducing losses in transmission and distribution systems. The
methodology is also useful for evaluating small generation projects, e.g. mini
hydro, or plant rehabilitation. Finally, reliable estimates of LRMC enable
financial targets for the utility to be set that encourage the use of existing
capacity if it is in excess and lead to existing consumers paying for the
costs they incur.
Selected Issues of Energy Pricing Policies

A. Effects of Energy Pricing Policies

3.1 Given the simplicity of pricing theory, it is essential that Domestic pricing policies recognize constraints both institutional and those implied by a feasible planning methodology. Institutional constraints include distortions of various factor prices. Planning constraints arise because of limitations on data and other resources; lastly, the Government will have many socio-political goals besides those of economic efficiency, such as income distribution and independence from external shocks. "Correct" pricing of energy, both for evaluation of investments and allocating demand, is still important. A comprehensive approach to energy pricing policies recognizes the need for reconciling the objectives of economic efficiency, financial viability and equity. This requires balancing of both the pricing principles and domestic pricing goals. A clear understanding of economy-wide energy linkages is vital in any type of economic system. It will help provide right market signals and information that encourage formulating appropriate domestic energy policies. At the aggregate level energy sector must be recognized as part of the whole economy. Energy planning requires analysis of the links between the energy sector and the rest of the economy. Such links include the energy needs of user groups, the input requirements of energy producers and the impact on the economy and on energy supply and demand of domestic pricing policies. At the second level the comprehensive approach treats the energy sector as a separate entity composed of subsectors as petroleum, natural gas, electricity, renewables and so on. This permits detailed analysis, with special emphasis on interactions among the different energy subsectors, institution possibilities and the resolution of any resulting policy conflicts. The third and most disaggregate level pertains to analysis within each of the energy subsectors. It at this level that most of the detailed evaluation, planning, and implementation of energy projects is carried out by line institutions (both public and private). Formulation of appropriate pricing policies reconciling efficiency, financial viability and equity objectives and their effective implementation require interactions at all three levels.

Pricing Patterns 1973-1988

3.2 During the last fifteen years from 1973 until early 1988, energy prices in both oil importing and exporting countries generally did not cover economic costs except in the case of some petroleum products. The fall in international oil prices since 1986 has improved the relation of domestic energy prices to economic cost, but significant distortions do remain in some countries of the region. Specific inadequacies in price policies and structures have included the following:

(a) Petroleum Product Prices, while usually reflecting economic costs on average, have often involved cross-subsidization (with gasoline being priced above economic cost, and kerosene, LPG and feedstocks being

Ex-refinery prices have generally been set above border prices, but major petroleum price distortions have persisted in some countries where product prices still remain well below border prices even after the fall in international oil prices.

(b) **Natural Gas Prices** have typically been pegged to the price of fuel oil. In countries with large domestic natural gas reserves (Algeria, Egypt, Syria, YAR), the economic value of natural gas may fall below its fuel oil equivalent. Gas pricing is an important issue as key investment decisions to explore and develop natural gas are sensitive to the economic price of domestic gas and its use in power generation.

(c) **Coal and Lignite Prices** for domestic production, are usually priced below average imported costs and domestic coal prices range from 25% to 98% of economic cost. In contrast, the prices of imported steam and coking coal are set at CIF costs in all countries of the EMENA Region. The concept of marginal pricing for domestically produced non-traded coal has yet to win support.

(d) **Electricity Prices** have generally been set below LRMC and remain substantially lower except in some countries. Governments have shown reluctance to increase electricity tariffs in the past and the electricity pricing issue could become acute once more should oil prices increase in the future.

3.3 Resolution of the pricing issue has been complicated by the fact that energy price setting is typically the responsibility of government rather than energy enterprise. In setting energy prices, governments have given greater weight to industrial competitiveness, impact on household budgets and inflation, than economic efficiency or the financial viability of energy enterprises. Lower international oil prices have narrowed the gap between domestic energy prices and their economic costs. However, the energy pricing issue continues to exist and could become more acute, if in the future, international oil prices rise and/or exchange rates depreciate. The falling oil prices at present offers the opportunity to adjust all domestic energy prices to reflect their economic costs.

3.4 The Governments are clearly aware of the cost of inefficient energy prices, but have been reluctant to increase energy prices for a variety of reasons. The Governments are concerned: first; that an increase in the price of energy and particularly of electricity and kerosene would adversely affect the welfare of the poor. Second; that increase energy prices would erode industrial competitiveness of their exports and would, in the case of use of substitute fuels like kerosene and firewood, contribute to severe deforestation problems with undesirable ecological effects. Third, that

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1/ Pricing gasoline and diesel oil above their economic cost can be justified to some extent as a means for recovering road user costs.
raising energy prices would be inflationary and this, in turn would have an adverse effect on economic growth; thus subsidized energy prices are perceived as a tool for poverty alleviation and inflation control. The concerns of the Government are understandable. But it is important that a thorough evaluation of economic costs and benefits of eliminating energy subsidies should be made to formulate a comprehensive approach to energy pricing policies. Such a framework should address a series of specific pricing and related issues. These include:

(a) What should the relation be between the prices of primary energy fuels such as coal, crude oil, and natural gas charged to power utilities? And what relation should these prices bear to those charged to the producers?

(b) What should the relation be between the prices of petroleum products (liquid petroleum gas, gasoline, kerosene, diesel, and fuel oil) at the ex-refinery price, as well as at the retail price?

(c) What implications does a specific energy pricing regime have for the future market shares of primary energy fuels and secondary energy supplies (such as electricity) in the total energy supply mix?

(d) At what rate should indigenous nonrenewable energy resources in developing countries be depleted, and does the price applied to any given resource satisfy the objectives of the depletion rate?

(e) What should the relation be between the price of competing fuels at the end-point of consumption, for example, between charcoal, liquid petroleum gas (LPG), kerosene, natural gas and electricity for domestic cooking; between gasoline, diesel oil and LPG as fuels for transport; between coal, fuel oil, and natural gas for thermal power generation?

(f) Should energy prices be used as a mechanism to achieve the objectives of income distribution in a society? If so, how?

(g) What are the effects of increasing energy prices on Industry, Transportation and Household sectors? How should these effects be evaluated? and finally,

(h) What implications does a specific energy price regime recommended have on macro parameters such as revenue receipts, balance of payments and structure of the economy?

3.5 The complexity of the above questions is such that answers can only be provided in a country-specific setting. Nevertheless, guidelines can be used to delineate the appropriate range of energy prices for specific products as well as for electric power. The guiding principle of pricing in economics is that tradeable forms of energy prices should reflect their relevant opportunity cost which is defined as the border (export or import) price. For non-tradeable forms of energy prices should be set to reflect the long-run marginal cost of production and distribution. Correct prices have the great theoretical and practical value of providing signals which will, under certain
conditions, contribute to guide the rational allocations of scarce resources. The costs of subsiding energy prices would result in misallocation of resources, encourage wasteful consumption and inefficient energy use and loss of much needed revenue receipts to the national budget and, in the case of energy exporters loss in export earnings. Subsidies no matter how justified socially severely distort demand patterns for energy and give rise to wasteful consumption of subsidized substitute fuel, since many energy-consuming equipment can easily switch fuels, if the financial incentive to do so is high. For example, substitution of diesel and LPG for gasoline. When the retail price of diesel/kerosene are permitted to differ considerably, it is inevitable that these subsidized fuels will be diverted to uses other than those originally intended to be subsidized. Subsidized energy prices also entail costs associated with putting in place administrative and bureaucratic mechanisms necessary to ensure the operation, maintenance and monitoring of the price control regime. It is therefore important that while formulating energy pricing policies a thorough evaluation of economic costs of perpetuating the subsidized energy pricing status with that of costs and benefits associated with eliminating price distortions should be made.

3.6 In attempting such an evaluation it is necessary to reconcile the efficiency and financial viability principles with equity and welfare objectives. Planners, economists, engineers should provide a framework of energy pricing to the decision makers such that both the approach to energy pricing and the recommendations meet the efficiency, financial viability and equity criteria. A first step in this direction is to address the concerns of the decision makers. As discussed earlier decision makers are extremely sensitive to effects of increasing domestic energy prices on industry, transport and household sectors, and are concerned with macro implications of increases in energy prices viz, inflation and erosion of competitiveness of industrial exports. These concerns are normally based more on perception of limits of tolerance of energy users than on an impartial techno-economic basis of analysis and evaluation. The planners, engineers and economists have the responsibility to provide a rigorous analytical pricing framework to enable the decision makers to make the right choices. The formulation of such a rationale include three crucial steps. First, a macroeconomic analysis of energy price adjustment. Second; the evaluation of sectoral implications of energy price adjustment policies and, finally, the formulation of an integrated pricing approach with the analytics of alternate pricing policy options.

Macro economic Implications

3.7 Analysis of macro economic implications of energy price adjustment focusses on the importance of:

(a) the degree of nominal wage response to the CPI;

(b) difference in input proportions across sectors;

(c) the sensitivity of the traditional sector such as agriculture whose price does or does not rise;
(d) the growth in the money supply which accommodates an increase in the demand for money resulting from increased output prices, and the resulting effects on the CPI, output, employment and profits in the modern sector and input demands;

(e) the effects of the removal of energy price subsidies on exportable energy surplus;

3.8 Macro economic analysis of energy price increases can be undertaken through the complex integrated energy/economic models or a simple aggregate model that exposes the structure of the problems. The combination of process analysis type energy system models and macro economic models help identify relationships between the energy sector and the economy. These models are also used to analyze the relationships between economic growth and energy in a short to medium term horizon where data limitation may not allow sophisticated analysis. The basic macro economic implications can also be evaluated in the simple aggregate model.

The effects of increasing energy prices on the industrial sector

3.9 It should be noted that at any given time the structure of energy demand in the industrial sector reflects the then prevailing prices. As the Government policy changes to reflect higher domestic energy prices, not only will the demand for energy in the industrial sector change, but so will the structure of the industrial sector and this, in turn, will also be reflected in a shifting comparative advantage within the industrial sector. As energy prices rise, some firms will adjust towards more energy-efficient capital equipment (where such a choice does not exist) and others (where such a choice does not exist) will have to absorb the increased costs and thus, may lose their comparative advantage. Consequently, in the aggregate, some industries may even expand whereas others may shrink resulting in a changing more efficient industrial structure.

3.10 The structure of energy demand in the industrial sector depends on the extent to which capital, labor and energy can be used in different proportions in response to changes in their prices, and on the characteristics of production. The substitutability of capital, labor and energy is a critical determinant of energy demand and the characteristics of production determine the extent to which fuels can be substituted for each other in the different industrial subsectors. If the long-run objective of the Government is to reduce the subsidy provided to energy, a basic understanding of the structure of energy demand becomes necessary. For the industrial sector, in particular, issues that need to be resolved include the responsiveness of energy demand to price changes, the possibilities of interfuel substitutions within specific industrial subsectors, and the effect of energy price changes in the cost of manufactured output and, thereby, on international competitiveness.

Effects of Energy Pricing Policies on the Transport Sector

3.11 Another area of concern for the Governments is the impact of higher energy prices on the transport sector. The available evidence on cross-country data indicates that the impact of increased transport costs on final
commodity prices to be quite limited as transport cost do not make up a large share of the total costs of marketing and production. Short-run price responsiveness of fuel consumption can come about through diverse means such as improved maintenance, and substitution of modes of transports viz. buses for cars. Over the longer term, various other adjustments and substitutions can take place and this would include a change in the capital stock which reflects a less energy intensive structure -- as energy prices are raised to reflect their opportunity costs. The longer the delay in making such changes, the more the economy will be locked into a pattern of location and capital stock which is less energy efficient than it could be as the myriad of adjustments and substitutions that could have taken place are prevented.

3.12 The most important issue facing the governments in developing countries today is the price of diesel oil relative to its world market price and to the domestic prices of other petroleum products; aviation fuel and gasoline are generally priced above their import prices while diesel and kerosene are priced well below their respective world prices. This price distortion in favor of diesel and kerosene has encouraged the more rapid growth in consumption of these products and a rapid increase in the percentage of vehicles using diesel. In addition, it encourages a rate of dieselization that is greater than economically desirable. In order to reduce this distortion and, thereby, reduce the aggregate budget and economic subsidies, there is a need for increasing more rapidly the nominal price of diesel than that of gasoline. This, however, raises the issue of whether or not the diesel price can be increased more rapidly than the kerosene price given that kerosene can, at least in part, be substituted for diesel in the industrial sector, and to a lesser extent, in transport. Available information suggests that when kerosene approaches 20% of the fuel mixture, engine performance deteriorates and maintenance costs increase. Thus substitution is limited. The Government could dissuade substitution of kerosene for diesel by disseminating information to truck and bus companies about the extra maintenance and repair costs associated with blending kerosene with diesel and by taxing bulk transport and bulk sale of kerosene in the industrial sector.

Effects of Energy Price on the Household sector

3.13 The structure of energy demand by the household sector depends in large measures on the preferences of the consumers. The substitution away from energy as energy prices increase depends on the willingness of consumers to substitute between energy and other goods in the consumption basket as well as on the extent to which there would be reduction in the purchases of energy consuming appliances such as kerosene stoves and the replacement of existing appliances that use energy more efficiently. Income growth is also an important characteristic of energy demand; the increases in the demand for energy and the extent of substitution from one source of energy to another as household incomes rise are important considerations. Finally, the extent to which fuels are substituted for one another as their relative prices change is likely to be dependent on the urban/rural nature of the household and its geographical locations in the country.

3.14 An important aspect of any change in energy pricing policy is its distributional effect. Any increase in energy prices will lead to a loss in welfare of all household consumers. The welfare loss also varies by the size
of household; it increases with the size. These effects have obvious policy
and administrative implications. While deciding energy price increases as
well as while designing compensatory measures to provide relief to the poorer
sections of the household sector the policy makers should strike a balance
between the objectives of eliminating subsidies and improving the poverty
alleviation.

B. Some International Experience

3.15 Prior to 1973, the real domestic price of commercial fuels in most
countries had been declining. Since 1973, many developing countries have
taken steps to price energy at international levels. But these countries have
differed in the way in which energy for direct consumption (e.g. motor
gasoline and aviation fuel) and that for intermediate use (e.g. fuel oil) have
been priced. In general, products for direct consumption have been taxed more
heavily than those for intermediate use, a pattern followed very much by the
industrial countries. Also, in general, oil producing countries have tended
to price energy at well below the international price. In some case, and
specifically for kerosene and LPG, the domestic price in many countries is
subsidized in the belief that higher prices would affect the incomes of the
rural and urban poor. Consequently, kerosene, natural gas, LPG and diesel oil
largely used by the industrial, transport and power sectors and electricity
for certain low-income class of customers have been subsidized. This
structure of prices has introduced distortions in the energy demand pattern.

3.16 If one makes the distinctions between oil-importing and oil-exporting
developing countries, in oil-importing countries the nominal and the real
price of petroleum products has risen whereas the opposite holds true in the
oil-exporting group. For example, in Brazil, over the period 1973 to 1977,
the retail price of kerosene increased by 196% and that of gasoline by 334%.
Similarly, in India, the increase was 156% and 182%. On the other hand, the
figures for Mexico, an oil-exporter, show a decline of 33% for kerosene, but
an increase of 42% for gasoline, and for Egypt, another oil-exporter, a
decline of 17% for fuel and diesel oil.

3.17 As far as gasoline is concerned, most countries have tended to raise
its price after 1973, but as of 1977, Bolivia, Burma and Colombia were the
very few countries which continued to subsidize regular gasoline by pricing it
domestically below its world price. Many other developing countries, such as
Ethiopia, Ghana, Lebanon, Sri Lanka and Turkey, though not selling gasoline
below its world price, had reduced their gasoline taxes permanently to ease
the burden on the consumers by absorbing part of the international price
increase. Also in many countries, the real price of electricity has either
declined or not changed very much since 1973 because much of it is produced
from coal or hydro where prices have not reflected the changes in
international petroleum prices.

3.18 The effects of increased energy prices on energy demand in the short
term are not very large, particularly in developing countries. This is
because the full adjustment process requires a change in the utilization of
capital stock, an adaptation and modification of the energy efficiency of
existing capital stock and the replacement of the existing capital stock.
Adjustment of the capital utilization rate can be made in the short run, but
the replacement of capital stock is a long-run phenomenon, whereas modification of the capital stock (retrofitting) can probably be accomplished in the medium term. Nevertheless, the oil price increases of 1973-74 have had a significant effect, albeit over quite a few years, particularly in the industrial countries. The rise in prices plus other non-price conservation measures have reduced the intensity of energy use in these countries; the ratio of total energy use per thousand dollars of GDP has declined by 2% per year for each year from 1973 to 1980. This has resulted in a savings of 10 million barrels of oil equivalent per day, or almost 15% reduction in demand than what would have been the case in the absence of the price change.\textsuperscript{1}

3.19 The growth of income in developing countries, of course, contributes towards increased energy consumption and this tends to mitigate the effects of increased prices on demand. In developing countries, long-term income elasticities tend to the higher than in the industrial ones -- 1.3 compared to 1.0 -- whereas the reverse is true for long-term price elasticities -- 0.3 compared to 0.4. Thus each 10% increase in price results in a long-run reduction of energy demand by 4% in industrial countries and by 3% in developing ones.

3.19 In developing countries, there is some preliminary evidence indicating that the energy intensity of industries may be declining. Also in Brazil, an increase in real gasoline prices by 116% has led to a reduction of gasoline consumption from 3,700 litres in 1973 to 2,020 litres in 1978.\textsuperscript{2} Relative price changes may have also led to undesirable inter-fuel substitution. Subsidized prices of kerosene have, in many developing countries, led to the substitution of kerosene for diesel oil, and in some cases to modifications of gasoline engines. Furthermore, black market sales of kerosene in the urban centers have, in some countries, led to increased use of firewood and accelerated soil erosion and deforestation. Also, the potential for undesirable interfuel substitution exists within the existing relative price structure.

C. Alternative Pricing Policy Options

3.20 Evidence from international experience indicate that the transition process or the adjustment from the current pricing structure to the desired one is of major concern to policy makers. The basic question they face is, how should they adjust their domestic energy prices to levels that reflect their opportunity cost? Three options can be considered. It is not possible to arrive at any conclusion regarding the superiority of one option over another as determination as to the choice of options can be made only by the Government after a careful analysis and taking into account the specifics of each country's situation.

3.21 The instinctive answer to the transition process seems to be to do it gradually. This is based on concerns about the effects of a sudden price increase on producers and consumers who have difficulty in adjusting to rapid price changes. The basic rationale for gradual price increases is the idea that this will minimize adjustment costs. If the path of the energy price is

\textsuperscript{1} World Development Report, 1981. The World Bank, Washington, D.C.

\textsuperscript{2} Other fuels such as alcohol, LPG, kerosene, and diesel may have been substituted for gasoline as a result of this price increase. The extent of substitution is not known.
announced in advance, producers and consumers can adjust their stocks of energy-using durable goods gradually. This, in turn, would eliminate the sudden losses to consumers and bankruptcy among producers.

3.22 These are the benefits, but there are also costs to such an approach. A program of gradual removal of energy subsidies thus, allowing the domestic price to rise to the world market price faces two main economic problems. First, the domestic price must rise relative to world price increases during the adjustment period. This places a strong restriction on the rate of increase of the domestic price; it must exceed the domestic rate of interest. This program, therefore, presents a strong incentive for hoarding in the private sector. Second, investment undertaken while energy prices are still below world market prices will still be energy-inefficient. The inefficiency will end only after a full generation of the replacement of capital equipment and consumer durables after the domestic price reaches the world level. This could prolong the life of the capital equipment using excessive energy for several years after the adjustment program is finished.

3.23 An alternate policy option that would seem to reduce the potential hoarding problem would be to remove the energy subsidy in unannounced discrete jumps in the price. This would seem to reduce the certainty attached to the margin between the energy price increase and the domestic interest rate thus, reducing the incentive to hoard. The gains of this policy are mainly illusory, however, as the fundamental incentive to hoard is not removed. In addition, the policy would create speculative bubbles around times when the private sector expects a discrete price increase; and this expectation would be based on past official behavior regarding energy price increases.

3.24 In addition to speculative problems associated with energy as a storable durable asset, a program of discrete unannounced jumps makes the path of energy prices to capital investors uncertain. This makes the marginal productivity of waiting until the price situation becomes clear before investing very high and thus leading to delays in investments. Therefore, an implicit policy of occasional discrete price jumps could create a disruption of investment in the private sector by maximizing uncertainty and the return from waiting. The non-economic gains of this adjustment policy would have to be substantial to outweigh these economic losses to the development program.

3.25 A third policy option would be to move domestic prices suddenly to world market levels, and simultaneously to recycle the revenues to energy consumers in the form of a temporary subsidy to income proportional to the initial energy consumption. The income subsidy could then be phased out gradually along a path keyed to the ability of producers and consumers to adjust capital and durable inputs. The gains from this policy package include the fact that the jump to world market levels would provide an immediate incentive to replace capital stock and durables with energy efficient units. So the move to energy efficiency would be completed after one turnover of the capital stock beginning from the time when the policy is implemented. Also, the immediate jump would forestall any further speculation on energy prices and release any existing energy hoards into productive use. Furthermore, the initial losses to "locked in" consumers and producers will be proportional to their existing energy consumption. So an initial subsidy to income also proportional to the initial consumption level could eliminate the initial
capital losses. A gradual phasing out of the subsidy as consumers and producers are able to replace existing capital into energy efficient units would serve exactly the same purpose as a gradual price adjustment, permitting a smooth transition from the short run to the long run. The final result would be the same without the incentives to hoard energy or delay adjustments to energy efficiency. A basic question, however, is the administrative feasibility and costs associated with such a program. But, if it were feasible to administer efficiently, this policy package would have the same benefits as a gradual removal of the energy price subsidy without incurring the costs. Furthermore, some realistic assessment also needs to be made about the speed at which the industrial structure would be permitted to adjust by the prevailing industrial policy environment. If the latter remains a constraint, then a strategy of gradual price increases may dominate one of sudden price changes.

3.26 The Government also has the option to either announcing or not announcing future price increases. The behavior of the firms and households would depend upon their expectations of the timing and level of future price. Given past price increases, it is likely that there will be expectations of future prices rises. If the Government follows a policy of announcing the trajectory of future prices, and actually implements that strategy, firms and households will undertake their adjustments and new investments with full certainty of future prices. So will individuals and firms with a capacity to hoard; they will now have the incentive to buy and store energy while the prices are low and release these stocks when prices are high. The extent to which this will actually take place will depend on the investments required to store alternate forms of energy. If, however, price changes are unannounced, an element of uncertainty will enter into the decision-making of firms and households regarding their investment behavior. Firms investing in new capital equipment will now not do so in capital that reflects the long-term price level; rather, they will make some judgement about the timing and level of future energy prices, compared to the useful life of different forms of capital and after weighing the costs and benefits in this uncertain environment reach some judgement. If future prices are correctly anticipated, then socially efficient investment decisions will be made. If the anticipations are, however, incorrect, then socially inefficient decisions will be made; the extent of this efficiency will depend upon the error in anticipation. This element of uncertainty will also enter the "hoarding decision" and less hoarding, than under conditions of certainty, will take place.

3.27 Whatever strategy is undertaken, the conclusion that energy prices must eventually reflect their opportunity costs remains valid. For non-tradeable forms of energy, such as electricity, the opportunity costs would be the long-run marginal cost of production and distribution; for tradeable forms the relevant opportunity cost would be the world price. The crucial question that policy makers will face once domestic prices approximate international prices, is whether to continue administering prices and make periodic adjustments to reflect a changing world environment or to decontrol prices and permit the market to adjust these prices. The answer to this issue would depend very much on expectations of future energy prices. If the expectations are that international prices will be essentially stable over the long run (though there may be short-term fluctuations) then decontrolling
prices eventually may be the better solution. If, on the other hand, international energy prices are expected to have very wide fluctuations over the long run, then administered prices to stabilize them domestically and insulate the economy from the large international gyrations, but still letting them reflect the long-run opportunity cost, may be the answer. In short, to enable the decision makers to take appropriate policy decisions, country specifics need to be worked out on a solid analytical framework. The role of engineers, planners and economists lies in providing sound basis of database for planning and undertaking rigorous analysis on the basis of which rational pricing policies are formulated. It is ultimately the quality of the professional staff that serves as a foundation and enables the policy makers to formulate right pricing policies.

3.28 Thank you very much for giving me this opportunity to present these lectures.
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