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Domestic Coal Pricing: Suggested Principles and Present Policies in Selected Countries

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DOMESTIC COAL PRICING

SUGGESTED PRINCIPLES AND PRESENT POLICIES IN SELECTED COUNTRIES

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ABSTRACT

This paper addresses some theoretical issues concerning the pricing of coal and notes a number of practical matters that must be taken into consideration in applying the theoretical framework to actual pricing policy. It first analyses the general pricing framework and conditions under which setting prices, rather than letting market forces operate unobstructedly, makes sense from an economic viewpoint. It deals with the basic pricing model, the role of prices, and questions such as tradeability and depletability of coal. Also, various general pricing policies are reviewed and their economic effects analyzed under different conditions of demand and supply for coal. For the case where price intervention is appropriate from an economic efficiency perspective, the paper develops a pricing approach based on a simplified algorithm which deals with uncertainty (reserve levels, international price projections, etc.) and with complicating factors such as multiple coal qualities and relative location of mines.

The paper also reviews coal markets in sixteen countries, of which eleven are LDCs. In all but two of them (the US and Colombia) there is price intervention. It was found that intervention is generating severe economic distortions in several of these countries, where partial or total freeing of market forces is warranted.

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PART I. INTRODUCTION

1. The domestic pricing policy for coal has become an important issue in the energy sector for a number of developing countries. It is a complex issue because of both the heterogeneous nature of coal and the wide range of circumstances under which it is found and used in various countries -- scarcity or abundance relative to domestic demand, exported or not depending on quality and accessibility, subject to depletion over a short or long period, used to replace other fuels ranging from petroleum to imported coal to natural gas to nuclear or hydroelectric resources.

2. The purpose of this paper is to discuss, at a fairly general level, what alternative pricing policies are possible, what price policies look like in the case of a selected number of countries, and to propose a classification system that could be used to provide a first-cut pricing rule in a particular case. Part II summarizes the underlying economic principles and theories that are relevant to questions of coal pricing. It reviews the basic model of economically efficient price determination, the rationale for using long-run rather than short-run marginal costs under certain circumstances, the relevance of border prices for tradable goods and the Hotelling theory of depletable resource pricing.

3. Also discussed are five general types of pricing policies that have been used or recommended for coal: hands-off pricing, average cost pricing, border pricing, two-tier pricing and long-run marginal cost pricing. The conditions under which each would or would not produce prices that are economically efficient are identified, and other advantages or disadvantages of each are noted.

4. Using certain simplifying assumptions, Section C develops and discusses an algorithm for deriving a country's basic coal pricing approach starting from the three critical parameters that determine the potential tradeability of domestic coal: the long-run marginal cost, the export equivalent value netted back to the mine-mouth and the import equivalent value similarly netted back. Depending on the relative values of these parameters and, subsequently, the timing and replacement fuel at depletion for certain paths through the algorithm, six distinct pricing approaches can be reached. Also, some preliminary ideas for handling two major complications in coal pricing--location factors and quality differentials--are presented.

5. Coal is a complex commodity with diverse physical characteristics (e.g., thermal value, ash and sulfur content) and locational features that generally will not translate into a <u>single</u> appropriate price either in the marketplace or at the mine-mouth. However, to keep the focus of this paper on the broader question of where to pitch a country's <u>set</u> of domestic coal prices covering the <u>set</u> of quality and locational characteristics of its coal, those structural aspects of pricing are considered only in the last section of Part II. Until then coal is treated as though it were a homogeneous commodity (or as though appropriate penalty and bonus values

could be derived to transform a price for a "standard" tonne of coal into a set of prices for the range of available coal supplies). Part III looks at coal price data and pricing policies in sixteen selected countries.

6. The analysis has focused on steam coal rather than coking coal because in contrast to coking coal, which is hardly substitutable by other energy sources in the steel industry, steam coal faces considerable competition both in the power and industrial sectors and, therefore, its price plays a more important role in energy planning and in fuel choices by consumers (para. 62). Annex 1 presents a simplified case for Thailand where the interrelationships between coal pricing and prices of other fuels is briefly investigated.

7. The focus of this paper is on coal pricing criteria that meet economic efficiency objectives. In practice, there are financial and social objectives that influence pricing policies. It is important to differentiate between the several objectives as there is no guarantee that a single pricing instrument will satisfy more than one objective. For example, pricing according to efficiency principles might make some established coal mines financially unviable (several such cases are discussed in Part III). However, in the case of mines that are economically justified, efficiency pricing will not generally lead to financial problems (paras. 29 and 43).

PART II. PRICING PRINCIPLES

A. GENERAL PRICING FRAMEWORK

1. The Basic Model

8. Whether a price is determined in a 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:

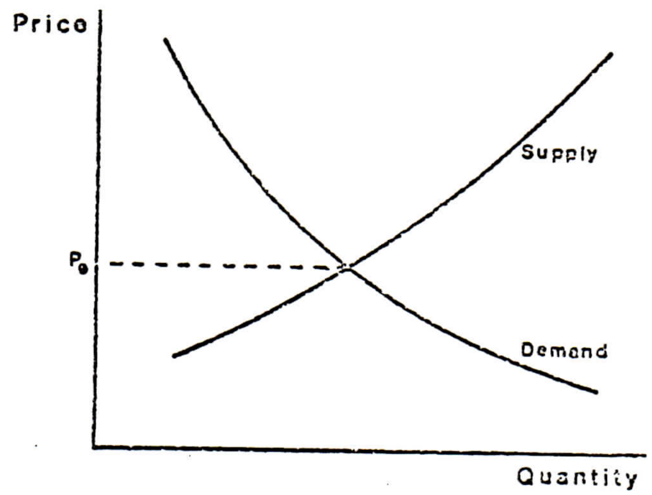

Figure 1. Equilibrium Price Determination

(i) It will clear the market. A higher price than P_e would induce producers to supply more than the consumers were willing to buy at that price. Conversely, at a lower price than P_e 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_e 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.

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.

2. Long-Run versus Short-Run Marginal Costs

9. There are some special features of the coal market that require some elaboration of the simple version of pricing theory discussed above. When economies of scale in coal 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 for coal 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 coal development program. Until demand reaches a level close to Q* the incremental cost of supplying an additional tonne of coal 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 of the mines, 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.

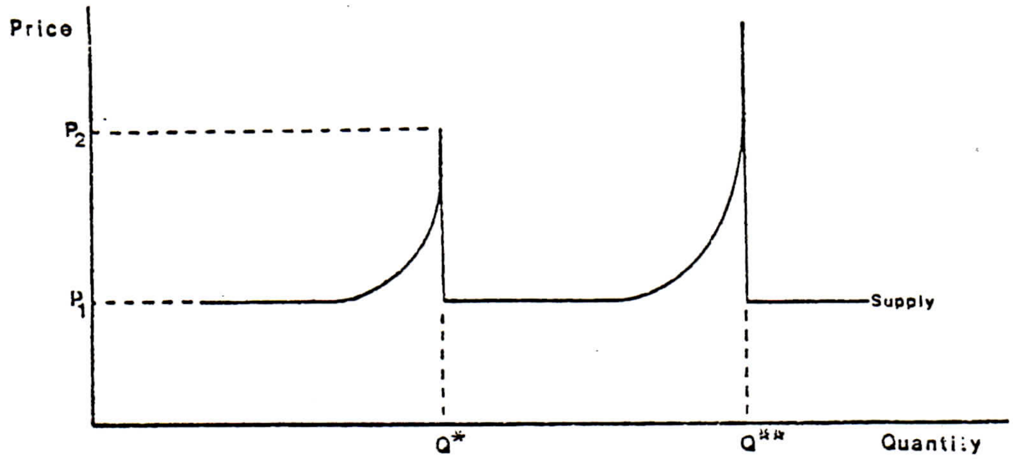

Figure 2. The Effect of "Lumpy" Investments on Price Determination

10. 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 (e.g., in coal-using equipment) 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 needs. There are many different smoothing formulas that can be used to calculate a long-run marginal cost (LRMC) price path. One method that has been widely used in the World Bank for electric power, gas and water is the "average incremental cost." There are, however, alternative approaches.1/ Annex 3 provides a brief discussion of some concepts and issues relevant for calculating LRMC.

1/ For additional detail on the justification for using long-run rather than short-run marginal costs, see Mohan Munasinghe, "Electric Power Pricing Policy," World Bank Staff Working Paper No. 340.
For a description of various methods of calculating LRMC, including the average incremental cost (AIC) approach, see Robert Saunders, et.al, "Alternative Concepts of Marginal Cost for Public Utility Pricing: Problems of Application in the Water Supply Sector," World Bank Staff Working Paper No. 259. For LRMC of natural gas supply, see Energy Department Paper No. 10, "Marginal Cost of Natural Gas in Developing Countries", Aug. 83.

3. Tradeability

11. A second modification to the simple pricing theory shown in Figure 1 is required to reflect the tradeable nature of 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 his 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 horizontal. Figure 3 illustrates the demand and supply curves for a traded 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 domestically and the difference (Q_p-Q_c) is exported. For a tradable 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.

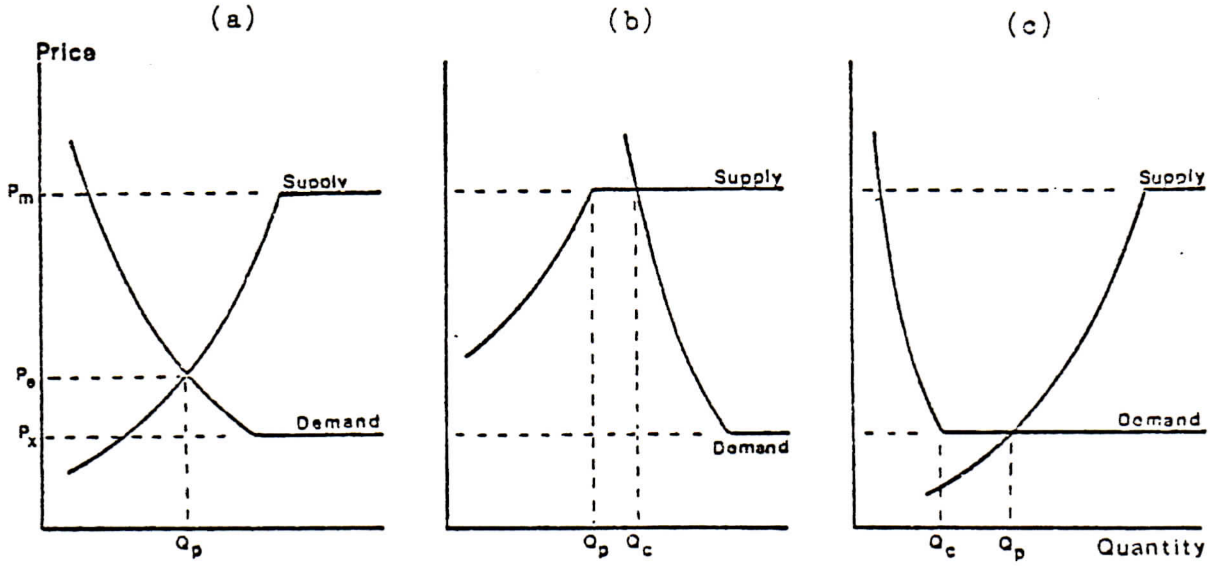

Figure 3. The Demand and Supply Curves for a Tradeable Good

12. 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 larger 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 (see Annex 2).

13. 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 (para. 62) price of imported coal or exported fuel oil. On the other hand, if lignite does not at the margin substitute for traded fuels, its value will be determined by LRMC plus whatever depletion premium might apply (para. 14). 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.[2/] 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.

4. Depletability

14. As is true of oil and natural gas, coal is a depletable resource. Since there is a fixed coal stock, consumption of a tonne today implies foregoing the consumption of a tonne at some future date. The value of this foregone consumption has been called many things in the economic literature: depletion premium, royalty, user cost, net price or

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2/ For additional discussion of the relevance and calculation of border prices see L. Squire and H. van der Tak, Economic Analysis of Projects, Chapters 3, 9 and 12.

resource rent. Thus the true economic cost of a depletable commodity consists of two elements: the extraction cost and the resource rent.

15. 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,[3/] 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.

16. In order to calculate the resource rent at any point it is necessary to know its demand curve. As the price of the resource grows over time the demand for it naturally falls (other things equal), until the resource is just exhausted as the price has risen so high that the demand has fallen to 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 demanded 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 demanded 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 the resource over time (here assumed to be constant), the initial stock of the resource and the relevant rate of interest over time.

3/ 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. See H. Hotelling, "Economics of Exhaustible Resources", in JPE, April 1931.

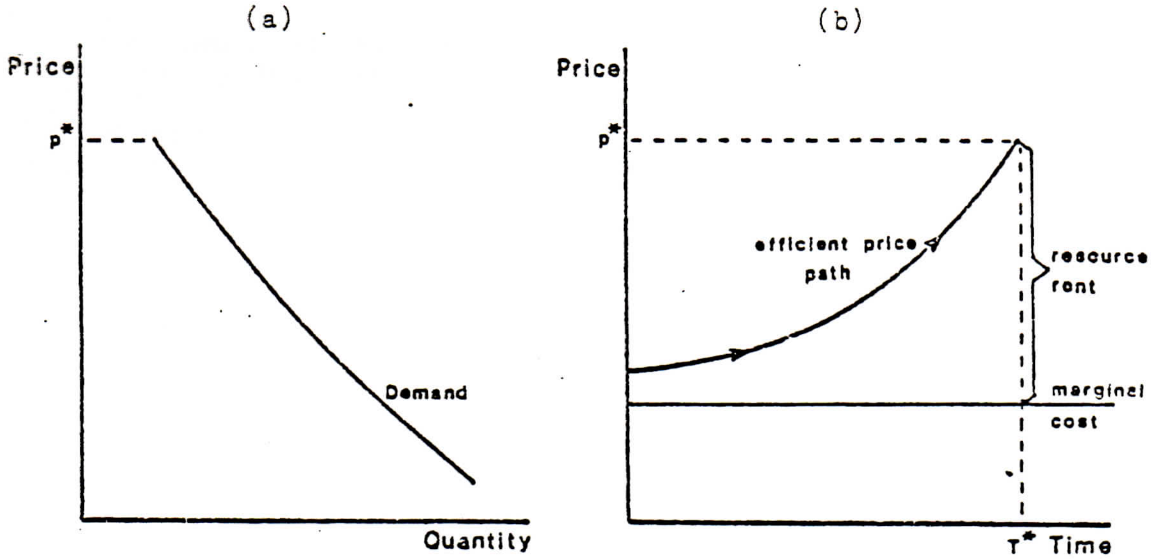

Figure 4. The Price Path of a Depletable Resource

17. 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.

18. 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 coal can be calculated by discounting back (at the opportunity cost of capital) from the full difference between the costs of imported and domestic coal 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.

19. Two further points can be made about the general application of the Hotelling principle to coal prices. First, in cases where domestic coal 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.

20. Secondly, where 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 $T_c - T_c$, during which, at T_g, 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.

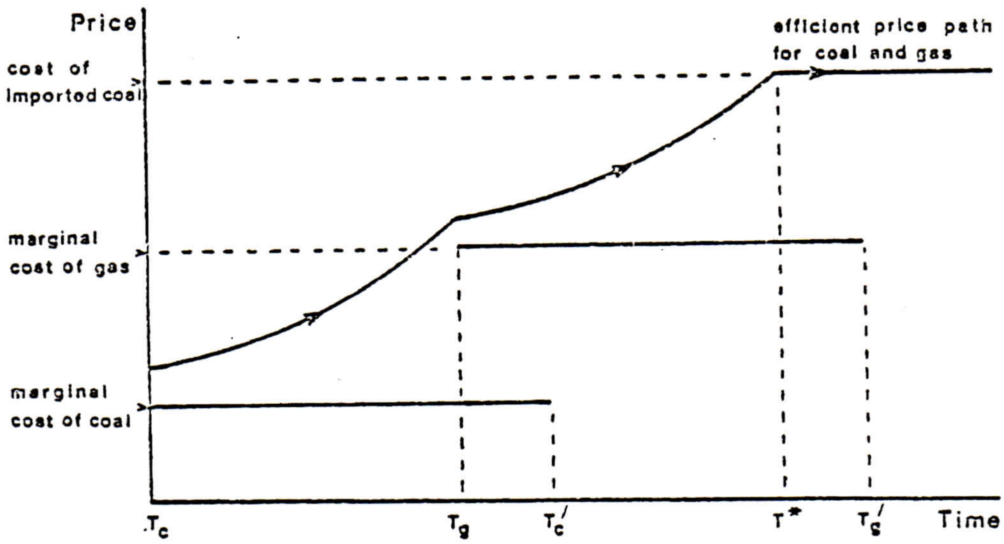

Figure 5. The Price Paths of Substitute Depletable Resources

21. To summarize, for countries whose coal 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

uncertainty around these estimates will be increased when coal will be replaced, at the margin, by another indigenous resource rather than imports with an exogenous value.4/

B. ALTERNATIVE PRICING POLICIES FOR COAL

22. In practice, the many countries that use coal have developed a range of different pricing policies to suit their individual circumstances. This section discusses five general types of pricing policies and indicates under which conditions each would or would not produce prices that meet the criterion of economic efficiency.

1. Hands-off Pricing

23. Certainly the simplest pricing policy to administer is to let the market forces themselves determine what the price will be. For coal, this is the policy basically followed by the United States and by Colombia (see Part III). In both cases, judged against the criteria set out for an efficient price in Section II-A, it has worked fairly well. This is probably in large part because in both countries there is a disaggregated market with many buyers and sellers of coal, resulting in a fairly competitive environment.

24. In countries where the coal market is characterized by a single producer and/or a single buyer, a hands-off pricing policy may not produce an economically efficient price. It is a well-known economic principle that a monopolist will, if given free rein, charge a higher price and produce a smaller quantity than would result from competitive production. Similarly, a single buyer, or monopsonist, will find it advantageous to offer a price just high enough to cover short-run marginal costs once his suppliers have made their investments. When a market is characterized by both a single buyer and a single seller, the price will be a negotiated one somewhere within the extremes mentioned above; it will be economically efficient only by coincidence.

25. Another possible disadvantage to hands-off pricing is that it may inhibit coal development during its early stages because of price uncertainty. A way around this was found by the Philippines where the government stepped in to bound the uncertainty by stipulating that the eventual negotiated price must lie somewhere between the production cost of a certain large new mine and the (higher) cost of Australian coal imports;

4/ There is a large technical literature on depletion issues. For a good, detailed summary of the various aspects see P.S. Dasgupta and G.M. Heal, Economic Theory and Exhaustible Resources, Cambridge University Press, U.K., 1979. For a more basic textbook description see M. Webb and M. Ricketts, The Economics of Energy, John Wiley & Sons, 1980, Chapter 3. For a short piece giving more of the flavor of depletable resource economics see R. M. Solow, " The Economics of Resources or the Resources of Economics," in the American Economic Review, May 1974, pp. 1-27.

the government also guaranteed the coal supply to the initial reluctant buyers, undertaking to import the difference if production targets were not met (see Part III).

26. A third possible problem with hands-off pricing is that domestic prices may move erratically in line with the prices of internationally traded coal if the local market is closely linked to coal exports or imports. Because of the unpredictable nature of energy demand and long lag time in bringing on stream new coal production, the world price of coal tends to "overshoot" in response to events such as a rise in oil prices or a political upheaval in one of the exporting countries. In the US, however, where over half of the coal produced is sold through long-term contract (i.e., deliveries scheduled over one to 30 year periods), the effect on domestic prices of short-term international price movements will be muted. It would also be possible to mandate a limit on the size of any single year's increase in domestic prices, but this might have the unfortunate side-effect of slowing the adjustment of domestic prices when there are sustained, long-term movements in international prices.

27. The major advantage of a hands-off pricing policy is that it permits maximum flexibility for individual buyers and sellers to tailor their contracts (of which the price is only one provision) to fit their respective needs. Premium and penalty amounts for quality and scheduling considerations can be negotiated on the basis of costs actually incurred by either party when partially unpredictable changes occur over time in the coal being traded. Such clauses can be specific to the mine, the buyer's boiler and the transport system linking them. This specificity of contracting is probably the only fully satisfactory way of handling the complex quality and locational dimensions of coal pricing. It is difficult to design a regulated pricing framework that can accommodate it.

2. Average Cost Pricing

28. In countries where coal prices are regulated, the most common basis for determining the regulated price is the average cost of production plus some profit component to generate funds for future investment in the industry. There are two ways that average cost pricing can be applied. The first is to specify both a single consumer price for coal and a single producer price, based on the historical average costs of delivered and mine-mouth coal, respectively. This simple version of average cost pricing is rarely encountered in practice, probably because it quickly leads to problems in clearing the market. On the supply side, in those cases where the marginal cost of production is rising, by definition the average cost will be below the marginal cost. If the mine-mouth price is based on recovering only average (i.e., historical) cost, the producers will have no incentive to expand production beyond current levels. Even at these levels, mines whose costs are higher than the average for the industry will be forced to make losses or close down, while mines with below average costs will find themselves profitable and, unless an appropriate profits tax system is in place, with little incentive to hold down costs through

efficient operation. On the demand side, with consumer prices uniform across the country there will be no incentive to situate coal using industries in locations that would minimize transport costs. Where average prices are below marginal costs, demand will be above its economically efficient level, and there will almost certainly be shortages.

29. To remedy some of these problems, a more sophisticated version of average cost pricing has evolved in some countries. India is an example of a mature (and complex) system (see Part III) with a range of both mine-mouth and consumer prices, resulting from consumers bearing the full transport cost. A set of company-specific prices are used based on the guiding principle that mine-mouth prices should be set to cover the full cost of production, subject to satisfactory operating norms, and a 10% return on capital employed. This assures financial viability for mines that fulfill minimum operating requirements.

30. There are problems, however, even with sophisticated versions of average cost pricing. The first is that it still provides little incentive for producers to operate efficiently. In fact, since reimbursement is on the basis of their costs, the higher those costs, the larger (in absolute terms) is their "profit". To ameliorate this problem in India, a system of efficiency standards is specified. Such a system is still no guarantee, however, that efficiency incentives are preserved. It is also extremely complex to introduce and to administer, and unless standards are updated regularly, they will rapidly become obsolete.

31. Disaggregated average cost pricing may also provide the wrong signals for interfuel substitution or for the point at which coal should begin to be imported or exported. For example, in an unregulated market where buyers are free to import, mining projects would never be undertaken where the cost of new production was higher than the equivalent cost of coal imports. But with a pricing system where those higher cost supplies can be rolled in with older, lower cost supplies, and where there is a guaranteed return on total capital employed, the incentive can be to continue to expand production beyond its economic limit.

32. A final problem with average cost pricing is that it provides an improper basis for setting coal quality differentials since they have no necessary relationship with production costs. This is a problem with any cost-based system of pricing (including LRMC), and will have to be dealt with separately if such a system is employed.

3. Border Pricing

33. There are many variations of using import or export (i.e., border) prices in setting a domestic coal price. Among developing countries, in Brazil and Indonesia the regulated coal price is determined partly with reference to a border price (fuel oil in Brazil, Australian coal imports in Indonesia). In the US it is not unusual to find individual contract prices for coal based on an escalation formula that incorporates international coal prices. In general, however, border prices are used indirectly, as a ceiling or an escalator, rather than directly to provide a rigid link between international and domestic prices.

34. A pure system of border pricing, where domestic prices would be net-back equivalents of the border price and would move in lock-step with it, would only be appropriate in countries where the opportunity cost of coal is directly related to its import or export value. Even in such cases one might favor a smoothing adjustment of some sort to avoid large fluctuations in world prices triggering erratic swings in domestic prices. In practice, the domestic price would be equated to the border price of coal delivered to consumers--so that the coal consumer would value domestic coal at its equivalent, say, export price. To derive mine-mouth prices, a complex system of, first, grossing up to a "delivered" price from the FOB price, and then netting back from this price to the mine would be needed. These mine-mouth prices would theoretically be different for each mine due to locational and quality factors (but not production costs). The regulatory complexities would rival those of average cost pricing systems, and would have the same requirements for frequent updating.

35. Border pricing systems would clearly not be appropriate for countries with large coal reserves and poor export prospects. For them, the opportunity cost of coal is set by domestic demand and supply conditions, and border prices would only become important as a ceiling to domestic production costs (at the point where imports became cheaper).

36. In general, then, border prices will provide an important reference point to countries whose domestic coal production is actually or theoretically competitive with coal (or substitute fuel) imports or exports, either now or in the foreseeable future. But in cases where domestic coal is a heterogeneous product (in terms of quality and distance from the markets), it will probably not be practical to develop rigid formulas linking mine-mouth prices to the border price. Rather, a system of price ceilings, based on import prices, or price floors, based on export prices, is likely to accomplish the same objective of signaling to domestic consumers and producers the real value of coal while reducing administrative problems.

4. Two-Tier Pricing

37. Two-tier pricing refers to systems where the regulatory authorities attempt to segment the domestic market for coal (either on the producer or consumer side) by cutting the price link between traded supplies (either exports or imports) and domestically produced or consumed supplies. It is thus used in countries whose domestic production competes with imports or exports, but where the government wishes to protect either producers or consumers from those competitive pressures. As seen in Part III, there are two versions, depending on whether the country is a coal importer (the European version) or an exporter (the South African version).

38. Consider first the European case (practiced in various forms by Federal Republic of Germany, France and the UK, among others) where the marginal cost of domestic coal production, even after government subsidies

to the coal industry, is higher than the cost of imported coal. The government's objective is to protect domestic coal producers and the employment they provide. In Germany, for example, this is done by imposing import quotas sufficient only to cover the difference between domestic demand and domestic production, and let prices for domestic coal rise above the international price. This system has the effect of causing the coal consumer to subsidize the producer and his employees, and of distorting fuel choices away from coal toward nuclear and other substitutes. Even as a policy for protecting employment it has little to recommend it from an economic viewpoint. A more efficient policy instrument would be a cash grant to any employer willing to hire the targeted workers. Such a policy would not distort fuel choice and would spread the burden for the subsidy over the general tax-paying population.

39. The other version of two-tier pricing is used to segregate the coal export market from the domestic market where LRMC costs are well below international prices. In South Africa, the government allocates export quotas to coal producers and sets prices for domestic sales which are lower than FOB export prices, but still generally higher than LRMC for coal qualities suitable for the local market.

40. South Africa's two-tier pricing system may be a rational by-product of the country's profit maximizing export policy. As a major low-cost exporter, the country's coal production and pricing decisions have a significant impact on the world price of coal. In a market where demand is not very price-sensitive, and where coal importers would be reluctant to grant a significantly larger market share to an already major exporter, even if a price advantage were offered, rather than by undercutting all competitors driving world prices down to its own LRMC, an exporter with market power should hold its export volumes down and keep prices up. In this way, the exporter, rather than the importer, keeps the resource rent.

41. Figure 6 illustrates the extreme version of this scenario, where Q_x is a fixed demand for the country's exports at price p_x. At higher prices the importers would turn to other suppliers and at lower prices they would still buy from others for strategic reasons. Figure 6(a) also shows the domestic demand for coal. In 6(b) these two demands have aggregated, and the supply curve superimposed. The market clearing price for the domestic market is p_e at which the quantity sold is $Q_1+(Q_3-Q_2)$, and the market-clearing price for exports is p_x at which the quantity $Q_2-Q_1=Q_x$ is sold.

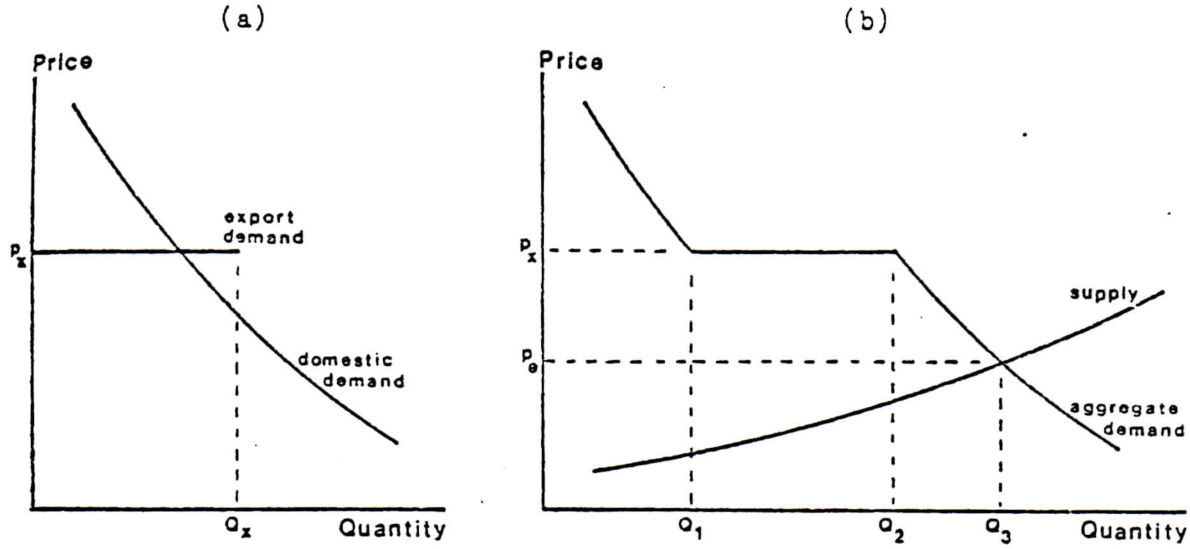

Figure 6. Two-Tier Pricing for a Coal Exporter Facing Fixed Export Demand

42. In summary, it is possible to construct a scenario under which two-tier pricing for an exporting country is economically efficient. It is however unlikely that any developing country with the possible exception of China will ever loom large enough in the export market to be faced either with limitations on its market share imposed by importing countries or will enjoy costs as low (and therefore rents as high) as those of South Africa. There is another circumstance for which two-tier pricing would be the appropriate response: where the exporting country also has large reserves of low-quality coal that is unsuited for export and that, at the margin, does not free the export-quality coal for export, the price should not be linked to the border price for the export-quality grades. Case II in Annex 2 provides an example of this situation.

5. Long-Run Marginal Cost Pricing

43. It is evident from the discussion above that the long-run marginal cost of production is an important pricing guidepost under a wide range of conditions. Because of the "lumpy" nature of coal investment, the relevant supply curve is based on long- rather than short-run costs (para. 10). The LRMC forms the lower bound for price whether considering coal exporters (para. 11), self-sufficient coal producers (para. 11), coal as a depletable resource (para. 20) or two-tier pricing (para. 40). Domestic prices should be below LRMC only when the LRMC is above the cost of imports, and then no further expansion of domestic production is warranted. Yet, because coal is both tradable and depletable (unlike electricity), coal prices would be set equal to LRMC only under special conditions. Section II-C proposes a system for classifying conditions relating to coal demand and supply, and an algorithm for identifying

appropriate pricing guidelines in a particular case. Since in most countries LRMC are increasing in real terms, LRMC pricing is likely to assure financial viability to economically efficient mines.

C. EFFICIENCY COAL PRICING FOR DEVELOPING COUNTRIES

1. An Algorithm for Coal Pricing

44. Previous sections of this paper have reviewed the economic principles relevant for setting domestic coal prices and the economic effects of various possible pricing rules under different conditions of demand and supply for coal. It becomes clear that the key to coal pricing policy is to start with a good understanding of the demand (domestic and export) and supply (LRMC and import) prospects of the country in question, and to establish whether conditions are appropriate for the free operation of market forces. Only then is it possible to determine the appropriate basis for domestic coal prices.

45. Figure 7 is an attempt to diagram the analytical process that one would go through for a particular country to derive its basic coal pricing approach should intervention in the market be found necessary. Some simplifying assumptions have been made to reduce the diagram to its essential components. First, the country is assumed to possess a single, or a relatively homogeneous set of, coal deposit(s). This makes the calculation of LRMC more meaningful and, for the moment, ignores the complications arising when the next best substitute fuel for one coal deposit is another, higher cost deposit in the same country. Second, the time dimension is subsumed in the T* variable. Since all three basic parameters (i.e., the LRMC, the export and the import equivalent prices)

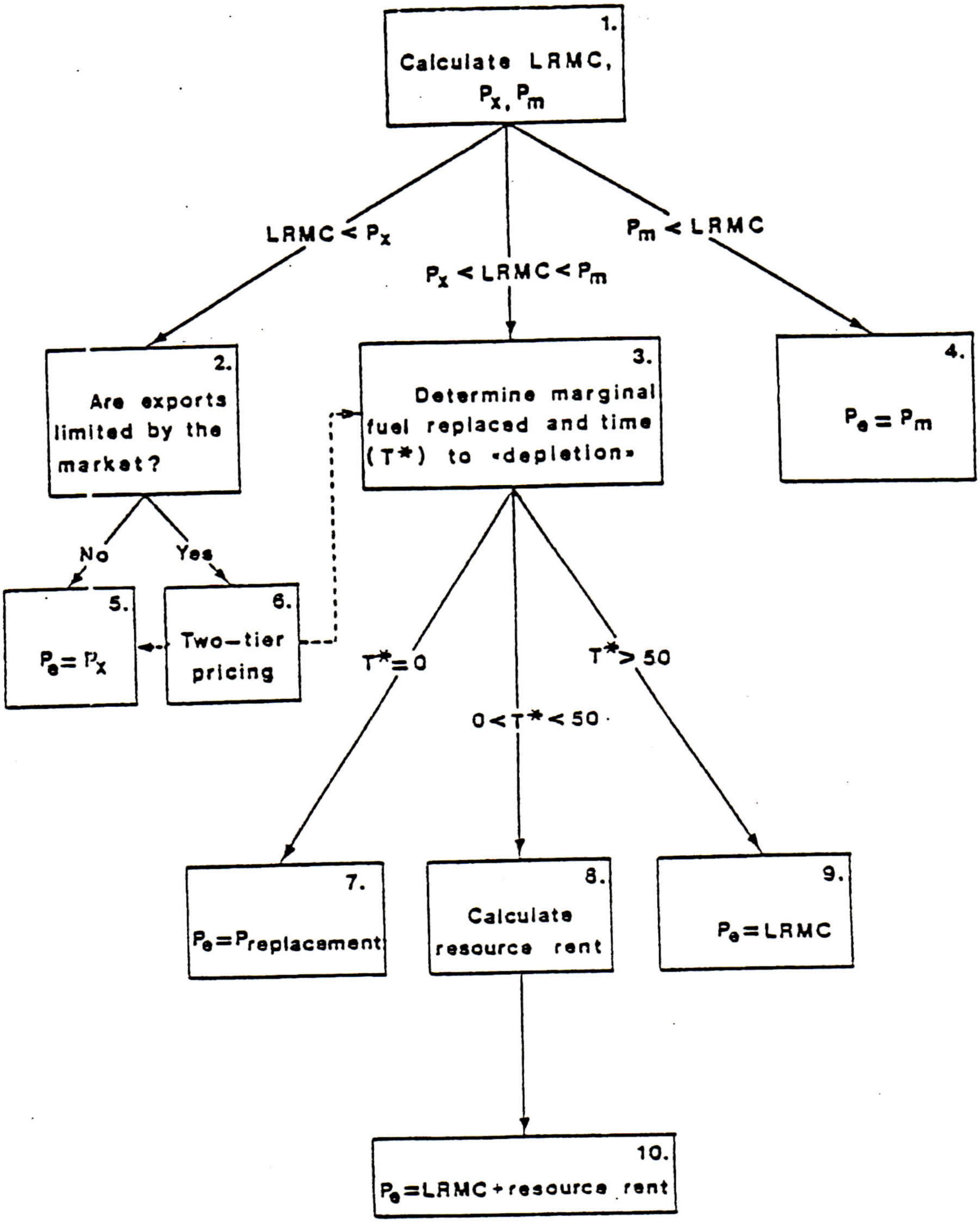

Figure 7. An algorithm for coal pricing

will change over time, it is entirely possible for a country to move from one category to another. If this happened, because of the depletability dimension in coal pricing, the appropriate price in the early period might well be a hybrid value, incorporating some foretaste of coal's future role vis-a-vis imports or exports. And, finally, the pricing rules shown as equalities in Boxes 4, 5, 6, 7, 9 and 10 are meant to imply equivalence at the point of final consumption. Netting these back to arrive at mine-mouth prices would be a complex task unless consumers are concentrated in location and have similar quality requirements.

46. To use the coal pricing algorithm, the first step is to estimate the three critical parameters that determine the potential tradeability of domestic coal: its LRMC, the export equivalent value, P_x, netted back to the mine-mouth, and the import equivalent value, P_m, similarly netted back, but in this case by way of the difference in transport costs of imports and domestic coal to the domestic market (see Annex 2). Depending on whether the LRMC is below P_x, above P_m or between the export and import equivalent prices, one of the three routes shown on Figure 7 is taken.

47. In the left-hand case, the country is an actual or potential exporter (since its LRMC is below the export equivalent price) and the focus shifts to the international coal market. Aside from its own infrastructure constraints whose cost should be reflected in the LRMC estimate, would exports be limited by market considerations or could the country export virtually as much as it was able and willing? If the latter is the case, then the efficient price for domestic coal (P_e) is its export equivalent value since every ton consumed domestically costs the country P_x in foreign exchange foregone. If there is some external limit on the country's exports, then some form of two-tier pricing will probably be appropriate. The export price tier should be whatever the world market dictates, while the domestic price tier should cover the LRMC and an allowance for the foregone future exports or domestic consumption of this depletable resource. This can be calculated by moving to Box 3.

48. In the middle case shown in Figure 7, the cost of domestic production falls between the import and export equivalent prices. Because of the high transport cost of coal, there are probably many developing countries that will fall into this category (para. 12). Difficult terrain and long distances may combine to give a negative value to the mine-mouth equivalent of an export price, so that even a country with a very low LRMC would not be a potential exporter. In such cases, it is necessary to consider the time path of domestic coal use and the marginal fuel it replaces either at present (T*=0) or at some future date (T*) when "depletion" (in the sense of first marginal replacement) occurs. If domestic coal supplies are very small relative to demand (T*=0) so that every tonne produced replaces, say, a tonne of coal imports or frees fuel oil for export, then the resource rent of coal is the full difference between its LRMC and the price of the fuel replaced. The price of domestic coal should be equal to that replacement value as shown in Box 7.5/

5/ The coal price should actually be just enough below that of the replacement fuel to provide the incentive to use the local coal. This comment also applies to the equalities shown in the other boxes of Figure 7.

49. If coal production is initially constrained by demand and only reaches the point where another fuel comes in to replace it after a period of years, then the size of the resource rent will depend on the date at which that substitution (i.e., depletion) begins. If that date is, say, more than 50 years in the future, then the present size of the resource rent is probably too small to do more than fine tune the much larger LRMC (para. 15). For this reason, Box 9 shows the efficient price to be equal to the LRMC. Where "depletion" can be foreseen in the next half-century, some allowance for the resource rent should be included in the price of domestic coal (Box 10). An exact estimation of the rent would probably require a dynamic optimizing model taking into account the long-run trend of the social discount rate, the optimal rate of extraction of the depletable resource, the future price paths of substitute fuels, the evolution of demand for electricity, etc.[6/] For many countries, however, electric power will be the dominant and marginal user of coal, and a good understanding of both the timing of substitution and the replacement fuel can probably be obtained from some fairly simple simulation exercises using the long-run power planning model. In cases where the replacement fuel is a non-tradeable such as hydro or (sometimes) natural gas, it would be difficult to derive the resource rent of coal <u>without</u> a system planning model.

50. In the right-hand case shown in Figure 7, the LRMC is greater than the equivalent price of imported coal. Under such circumstances the country should meet its incremental needs through imports rather than expanded (higher cost) domestic production, and the domestic price for all coal should be P_m.

51. Before moving away from the simplified world used to develop this simple pricing algorithm, two general comments are needed. First, each of the 10 boxes contains uncertainties and ambiguities that would arise in any attempt to apply the method directly. For example, in order to calculate the LRMC (Box 1), decisions have to be made regarding the best smoothing formula to be used, how to incorporate future coal exploration costs, whether to base the calculation on representative projects or on a slice of an investment program, what time period should be used, how to aggregate expected coal production of different qualities, etc. This paper does not discuss such issues, partly because it is premature to explore such details before the theoretical framework for pricing decisions has been broadly agreed, and partly because (based on experience in power and gas) the best way to handle them may be to gain practical experience by using the theoretical framework to look for solutions in particular cases, from which generalizations can later be derived.

6/ An example of the use of such a model to derive a depletion value (for natural gas) can be found in World Bank Report No. 4136-EGT, <u>Egypt: Issues of Trade Strategy and Investment Planning</u>, by Kemal Dervis and others, January 1983.

52. In addition to the hidden problems within each of the boxes of the algorithm, there is an invisible but contentious parallel issue shadowing each pricing rule: how should the rent be shared between producers, consumers and the rest of the economy? Economic theory provides a clear answer: pass the rent back to the producer and then capture it for the rest of the economy with an efficient profits tax.[7/] This system will ensure that both consumers and producers make their investment decisions based on the right pricing signal, and that the incentive for efficient operations is preserved for the producer. Ideally, coal pricing rules and taxation policies should be developed simultaneously so that the split of the resource rent included in the price will be the desired one.

2. Location Factors

53. In many countries coal is found in discrete deposits with different physical characteristics and perhaps serving entirely different markets. The US is an example with large-scale, low cost strip-mining in the west and long-established, higher cost underground mining in the east. Colombia is another example where difficult terrain, different mining conditions and inland population centers dictate that while coastal coal deposits have a potential for exports, inland deposits are used almost exclusively domestically.

54. Where there is complete separation of markets for different coal deposits, location factors present no analytic problem since the different deposits can be treated independently. For example, if the market for two deposits were completely independent, it would make no sense to calculate a single, aggregated LRMC to use as the pricing guideline for both. In most cases, and particularly where coal is used to generate power that is fed into a national grid, there will be some commonality of market served by the various deposits. Then the opportunity cost of coal in one area may depend partly on the marginal fuel replaced (perhaps in the future) by the coal in another area. Conceptually, each deposit should be treated separately with its own calculation of LRMC, and they should be linked by attempting to plot the times at which each deposit would become the marginal replacement for the next cheaper deposit. The result would be a cascading series of resource rents similar to that shown in Figure 5 for coal and natural gas. Annex 2 presents a simple example for the case of two deposits and a local and an export demand.

3. Quality Differentials

55. As noted at the outset of this paper, coal is not a homogeneous commodity, although it has so far been treated as such to simplify the pricing analysis. Whenever a country produces more than one grade of coal, and whenever the different grades are less than perfectly interchangeable in the eyes of the consumer (say, if priced on a thermal equivalent basis), then a single such price for the different grades will fail to meet economic efficiency criteria.

7/ See, for example, Keith Palmer, "Mineral Taxation Policies in Developing Countries," IMF Staff Papers.

56. Not only may a country have many different grades of coal, but many of the coal users will have boilers or other equipment that has been specially designed to utilize a particular specification of coal at peak efficiency. Any significant deviation from this specification will result in additional cost to the consumer. Different consumers will differ in their sensitivity to variations in coal quality. Unless this sensitivity is communicated in terms of financial penalties to the producers serving them, the appropriate incentive at the mine for washing and careful sorting of coal grades will not exist. Yet, for the other consumers in the same country, such costly mine-mouth procedures would not be economically justified. In an extreme case--which may approach the reality of the coal market--with m grades of coal and n consumers, one would have an (m x n) sized matrix representing the economic bonus and penalty values associated with each coal type/consumer pair.

57. To incorporate this degree of complexity into a regulated coal pricing framework is probably impossible. It is probably also unnecessary. Although with an economic model one could solve for the "shadow price" penalty or bonus value that would exactly clear the coal market, in practice the coal price alone is probably too gross a tool to convey the proper incentives to the producer for day-to-day operational efficiency. Other contract provisions between individual buyers and sellers--to dedicate specific reserves and identify substitute coals, to set limits beyond which coal is rejected as well as premium/penalty amounts for qualities within the specified limits, to agree on a delivery schedule and a procedure for sampling and analyzing the delivered coal, etc.--are probably better instruments than a simple price differential to promote the efficient functioning of the coal market. In a country with regulated coal prices, this would imply setting price floors or ceilings for the ranges of coal qualities that relate to their economic values (e.g., export qualities, lower thermal values that can be transported to market, lignite that can only be used at mine-mouth), and allowing the producers and consumers to negotiate individual contracts within the regulated price guidelines. Coal qualities that relate to their economic values (e.g., export qualities, lower thermal values that can be transported to market, lignite that can only be used at mine-mouth), and allowing the producers and consumers to negotiate individual contracts within the regulated price guidelines.

PART III. PRICING POLICIES AND PRICE DATA IN SELECTED COAL PRODUCING COUNTRIES

A. OVERVIEW

58. Part II presented a variety of pricing policies and the conditions under which they are, in general terms, consistent with economic efficiency. This section examines briefly how coal is being priced in practice in the context of a group of selected coal producing countries. The group includes five developed countries (US, FR of Germany, France, UK, and Japan) and eleven developing countries (South Africa, Zimbabwe, Argentina, Brazil, Colombia, India, Philippines, Thailand, Morocco, Turkey and Yugoslavia).

59. Attention has been focused on minehead prices since few developing countries keep statistics on delivered coal prices. Delivered prices usually vary substantially not only with distance from mines--which would in principle allow to estimate delivered prices by region--but also with a number of factors such as transport arrangement, size and regularity of shipment, etc., which conspire against generalization. This is unfortunate because in addition to examining the effects of pricing policies as reflected in producer (minehead) prices, a sharper focus on the parallel effect on coal demand and consumer fuel choices would have been possible if consumer (delivered) coal price data were generally available.

60. Table 1 overleaf presents minehead steam coal prices for the sixteen countries over the 1973-1982 period, expressed in 1982 US dollars per tonne of coal and per million Btu. The latter prices take account of the significant difference in calorific value among coals. Also included for the last six years are average CIF import coal prices per million Btu, as recorded in major Western European and Japanese ports, the main inlets for internationally-traded steam coal. Minehead prices also vary from region to region and with quality. The most representative region and quality has been selected for all countries except the US and Colombia, where a weighted average for all regions and qualities is included. Table 2 provides as reference average prices of delivered fuels (including taxes and subsidies) to power and industrial plants in the five developed countries selected in this Section.

Table 1: Average Minehead Steam Coal Prices in Selected Countries, 1973-82

Country/Year	1973	1974	1975	1976	1977	1978	1979	1980	1981	1982	Average Yearly Increase
	(in 1982 US$ per tonne)										(in %)
US	19.6	28.8	31.0	30.8	29.0	27.0	26.2	25.2	28.3	30.0	4.8
FR Germany	61.3	82.1	90.5	89.7	87.5	93.9	95.9	99.2	112.8	104.5	6.1
France	48.1	55.3	69.5	64.4	59.6	58.7	65.5	85.7	88.5	79.4	5.7
United Kingdom	37.9	41.1	56.4	54.7	52.6	52.0	70.5	86.8	111.2	91.5	10.3
Japan	-	-	-	63.5	72.1	80.4	71.0	70.1	81.5	77.9	3.5
South Africa	7.5	8.3	9.1	11.2	10.7	9.9	10.3	11.5	12.1	11.3	4.7
Zimbabwe	9.6	9.5	13.5	12.4	12.7	10.8	10.1	11.0	12.7	15.0	5.1
Argentina	17.7	14.7	5.1	7.3	7.4	8.6	12.3	16.1	12.1	9.4	-6.8
Brazil	31.7	26.1	26.2	26.6	26.2	25.1	24.4	17.7	33.0	39.1	2.4
Colombia	8.1	7.0	7.2	8.1	11.4	13.5	13.4	14.4	17.3	19.8	10.4
India	11.7	9.8	9.8	10.2	9.7	8.8	10.6	12.5	14.9	16.0	3.5
Philippines	23.2	36.8	31.8	31.0	32.3	26.0	26.6	33.6	42.1	44.2	7.4
Thailand	-	-	-	-	-	-	9.3	11.1	14.3	17.8	24.2
Morocco	29.4	29.6	28.1	29.4	26.7	27.8	29.8	30.3	37.3	40.2	3.5
Turkey	13.3	10.8	9.1	8.1	10.5	17.1	21.1	17.6	18.9	17.7	3.5
Yugoslavia	37.6	49.1	45.8	48.7	51.3	45.1	45.0	44.6	59.5	-	5.2
	(in 1982 US$ per million Btu)										(in %)
US	0.8	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	1.2	4.8
FR Germany	2.4	3.2	3.5	3.5	3.4	3.6	3.7	3.8	4.3	4.0	6.1
France	2.0	2.3	2.9	2.7	2.5	2.4	2.7	3.6	3.7	3.3	5.7
United Kingdom	1.6	1.8	2.4	2.3	2.2	2.2	3.0	3.7	4.7	3.9	10.3
Japan	-	-	-	2.7	3.0	3.4	3.0	3.0	3.4	3.3	3.5
South Africa	0.3	0.3	0.4	0.5	0.4	0.4	0.4	0.5	0.5	0.5	4.7
Zimbabwe	0.3	0.3	0.5	0.4	0.5	0.4	0.4	0.4	0.4	0.5	5.1
Argentina	0.7	0.6	0.2	0.3	0.3	0.4	0.5	0.7	0.5	0.4	-6.8
Brazil	1.8	1.5	1.5	1.5	1.5	1.5	1.4	1.0	1.7	2.2	2.4
Colombia	0.3	0.3	0.3	0.3	0.5	0.5	0.5	0.6	0.7	0.8	10.4
India	0.6	0.5	0.5	0.5	0.5	0.4	0.5	0.6	0.7	0.8	3.5
Philippines	1.1	1.7	1.4	1.4	1.5	1.2	1.2	1.5	1.9	2.0	7.4
Thailand	-	-	-	-	-	-	0.9	1.0	1.3	1.7	24.2
Morocco	1.4	1.4	1.3	1.3	1.2	1.3	1.4	1.4	1.7	1.8	3.5
Turkey	1.0	0.8	0.7	0.6	0.8	1.3	1.6	1.3	1.4	1.4	3.5
Yugoslavia	1.6	2.2	2.0	2.1	2.3	2.0	2.0	2.0	2.6	-	5.2
Memo Item: Average Steam Coal Import Prices (CIF)											
- into European Community					1.7	1.6	1.6	2.0	2.6	2.5	
- into Japan					1.6	1.6	1.6	2.0	2.5	2.5	

Sources: European Economic Community; Ministry of International Trade and Industry (Japan)

Table 2: Average Fuel Prices Delivered to Power and Industrial Plants (Tax and Subsidies Included), 1978-82
(in 1982 US$ per million Btu)

	Power Plants					Industrial Plants				
Country	1978	1979	1980	1981	1982	1978	1979	1980	1981	1982
USA										
Heavy Fuel Oil (HFO)	2.4	2.9	3.9	5.2	4.8	2.1	2.6	3.1	4.5	4.1
Natural Gas (NG)	1.6	1.7	2.0	2.6	3.3	1.7	1.7	2.0	2.8	3.5
Steam Coal (SC)	1.2	1.2	1.3	1.5	1.6	1.4	1.3	1.4	1.5	1.7
SC/HFO (in %)	51	42	31	28	34	67	52	43	34	40
FR Germany										
HFO	3.0	3.8	4.8	5.0	5.0	3.0	3.6	4.5	5.3	4.8
NG	2.2	2.4	3.0	-	-	1.5	-	-	-	-
SC	3.3	3.3	3.5	3.4	3.4	3.0	3.1	3.3	3.3	3.6
SC/HFO (in %)	109	87	74	67	69	100	85	74	62	76
France										
HFO	2.7	3.0	4.4	5.0	4.9	2.7	3.1	4.4	5.1	4.9
NG	-	-	-	-	-	2.8	2.9	4.1	4.6	-
SC a/	3.2	3.6	4.3	4.3	3.9	3.2	3.6	4.3	4.3	3.9
SC/HFO (in %)	120	123	99	84	80	118	117	98	85	80
UK										
HFO	2.6	3.2	4.7	5.1	4.8	2.9	3.7	5.1	5.6	5.2
NG	1.9	2.3	2.8	5.5	4.4	2.5	2.8	3.8	4.3	4.1
SC	2.0	2.4	3.0	3.1	3.0	2.0	2.3	3.0	3.0	3.3
SC/HFO (in %)	78	73	63	60	62	67	64	58	54	62
Japan										
HFO	3.2	4.1	5.8	7.1	7.0	3.0	2.8	4.9	6.2	6.8
NG	3.4	4.0	5.5	7.0	7.0	14.8	12.7	14.0	16.2	12.1
SC b/	2.2	2.1	2.3	2.7	2.6	1.8	1.7	2.2	2.7	2.7
SC/HFO (in %)	69	51	40	38	37	60	60	45	44	40

a/ Does not include imported coal; therefore, quoted prices overestimate average prices, especially in the case of industry which has access to cheaper imported coal.

b/ Internal transport cost not included in case of imported coal; therefore, prices quoted underestimate average cost to consumers.

Sources: OECD/International Energy Agency; IMF (International Financial Statistics); IBRD (Report No. 814/82).

61. With the exception of Argentina,8/ domestic steam coal prices increased by over 3% per year on average in real terms between 1973 and 1982, with prices in a few countries more than doubling. This was prompted by the oil crises of 1973 and 1979/80, which saw oil prices increase by more than 15% per year on average in real terms. In contrast to oil prices increasing in jumps, coal prices grew rather steadily over this period in most countries.

62. Since the 1973 oil shock, domestic minehead steam coal prices remained below fuel oil CIF import prices (on a Btu equivalent basis) in developing countries.9/ In some developed countries, however, steam coal has not been consistently competitive with fuel oil. As seen in Table 2, domestic coal has sometimes been priced not only higher than imported coal (see Table 1), but also higher than fuel oil on a heat equivalent basis, thus providing little price incentive for use of coal. However, as will be discussed later, coal use is sometimes forced upon consumers or encouraged though special non-price incentives. Where steam coal is available at or below international prices, it competes well with other fuels, even though a proper comparison requires coal to be penalized somewhat to take account of the higher costs arising in respect of its utilization (such as material handling, ash removal, gas and particle emission controls, lower heat efficiency, etc.). Taking account of these factors, recent studies show that for steam coal to be competitive in new 300-MW base-load thermal power plants, its price per Btu needs to be about 20% lower than heavy, residual fuel oil and about 40% lower than natural gas (in combined cycle plants). In the case of new coal-fired units substituting oil in existing oil-fired plants, the breakeven fuel price discount is as high as 50%.

63. Following is an analysis of coal pricing practices on a country-by-country basis.

B. INDUSTRIALIZED COUNTRIES

1. United States

64. Steam coal prices in the US follow market forces; there is no regulation by the Government. This is in contrast to natural gas and oil prices having been controlled for years, although now they also are substantially deregulated. The "hands-off" coal pricing policy is justified given that the US coal market is quite competitive. In 1981, the eight largest coal producers accounted for less than 30% of total production; consumption is even more disaggregated. As a consequence, domestic prices have generally followed LRMC with departures which can be

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8/ Triple digit inflation and erratic exchange rates make intertemporal comparisons difficult in Argentina.

9/ CIF import fuel oil prices per million Btu were less than US$1 before 1974, around US$2-3 in 1974-79 and close to US$5 in 1980-82 (all in 1982 dollars).

explained by short-term demand/supply developments. US coal reserves are amongst the largest in the world. According to the US Geological Survey, over 400 billion tonnes are mineable, with about half that much being actually extractable assuming conservative reserve recovery rates.[10/] The US authorities have placed emphasis on coal development as one of the means of reducing dependence on imported oil. Rather than providing special incentives to the coal industry, however, they moved to deregulate oil and subsequently gas prices to let the market work since domestic coal is not only competitive with oil but also with internationally traded coal. As seen in Table 2, steam coal became increasingly competitive as domestic oil and gas prices rose with deregulation. Thus, coal's share in the power sector's fuel supply rose from 49% in 1973 to 53% in 1980, while that of oil fell from 17 to 10%; the power sector represents over 80% of the total domestic US coal market. The "hands-off" pricing policy for coal has worked in an economically efficient manner in the US. Overall, producers and consumers have made investment decisions and fuel choices which are consistent with economic criteria.

65. The US is the world's largest coal producer. Production in 1982 was about 755 million tonnes (of which about 83% was steam coal) up from about 545 million tonnes in 1973 (for an average growth of 3.7% per year). Production responded quite rapidly to demand increases. The 1973 oil shock clearly indicated a revival of the then languid coal industry, and this manifested itself in coal prices and the noted supply reaction.

66. As seen in Table 3 below, and as a consequence of the coal demand increase starting in end-1973 the coal price surged in 1974 and reached a peak (in real terms) in 1975. Prices cleared the market and instilled in consumers a concern for energy savings. Since prices also rose above estimated LRMC,[11/] the proper investment signals were given to producers.

10/ The 1978 World Energy Conference estimated the amount of US technically and economically recoverable reserves of 177 billion tonnes of coal equivalent (i.e. standard coal of 7,000 kcal/kg or 12,600 Btu/lb).

11/ By the mid 1970s, LRMC in the US were probably in the US$25-30 range in the eastern (predominately Appalachian) region and well below that in the fast-growing western region. Accordingly, prices vary by region, with high transport costs restraining arbitrage.

Table 3: UNITED STATES - Average Minehead Steam Coal a/ Prices
(per tonne)

Year	Current US$	Constant 1982 US$ b/	Constant 1982 US$ c/	Constant 1982 US $ per million Btu d/		Memo Item Gas Wellhead Prices 1982$/m. Btu
1973	9.4	18.4	19.6	0.7 b/	0.8 c/	0.4 b/
1974	17.3	31.2	28.8	1.2	1.2	0.5
1975	21.2	34.8	31.0	1.4	1.2	0.7
1976	21.4	33.4	30.8	1.3	1.2	0.8
1977	21.8	32.2	29.0	1.3	1.2	1.0
1978	24.0	33.0	27.0	1.3	1.2	1.1
1979	26.0	33.0	26.2	1.3	1.2	1.3
1980	27.0	31.0	25.2	1.3	1.2	1.7
1981	28.9	30.6	28.3	1.2	1.2	1.9
1982	30.0	30.0	30.0	1.2	1.2	2.2
Average Yearly Increase	5.6%	4.8%				

a/ Includes some lignite and coking coal.
b/ Using implicit GDP deflator.
c/ Using international MUV index.
d/ On the basis of average calorific value of 11,130 Btu/lb.

Sources: US Energy Information Administration "Annual Energy Report"; IMF (International Financial Statistics); IBRD (Report No. 814/82).

After 1975, real prices stabilized while LRMC increased in real terms due to real wage increases and the effects of environmental and mine safety regulations.12/ Domestic coal consumption and exports continued to expand up to 1981, with large consumption increases between 1978 and 1981, period during which deregulation brought about large real price increases for natural gas to surpass substantially the coal prices on a heat-equivalent basis. Since these demand developments were largely expected, and the coal industry found it profitable to expand capacity, production responded by jumping 24% between 1978 and 1980. Thereafter, however, production stagnated, profitability fell and capacity developed only slowly, in line with expectations of modest expansion of the overall electric power market.

12/ By 1982, LRMC for the Appalachian region are estimated at over US$30 per tonne, according to recent studies undertaken for the Bank (a fuller discussion of this subject is made in a parallel Bank publication presently under preparation).

2. Federal Republic of Germany

67. Steam coal prices in the FR of Germany follow a "two-tier" policy: domestic coal is priced in line with production costs (but not fully meeting LRMC; see para. 38) while imported coal is marketed in line with border prices, with differential prices handled through a variety of administrative arrangements (para. 69). As seen in Table 1, domestic minehead prices were about 70% higher than CIF import prices in 1980-82. Table 4 overleaf traces domestic mine-mouth steam coal prices in DM and US$ for the 1973-82 period showing that, similar to the US, prices surged in 1974 and 1980 following the 1973 and 1979 energy crises; they kept growing only slowly thereafter.

68. Since steam coal imports are not subject to any significant import charges (such as duties and taxes) and since coal transport cost from ports to the largest German consumption centers are on average only marginally higher than transport costs from local coal producing areas (for example, barge transportation from Rotterdam to the Ruhr region, where most hard coal is produced, is estimated to cost less than US$5 per tonne),[13/] two-tier pricing is based on import quotas. In the case of coking coal, consumers are fully catered for by domestic coal at prices negotiated with producers (but under the oversight of Government), with the Government directly subsidizing consumers to the full extent of the price difference over imported coal.

Table 4: FR GERMANY - Average Minehead Steam Coal a/ Prices
(per tonne)

Year	Current DM	Constant DM b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu d/
1973	86.5	138.1	27.0	61.3	2.4
1974	126.1	182.2	49.3	82.1	3.2
1975	145.5	198.3	61.8	90.5	3.5
1976	157.5	205.4	62.3	89.7	3.5
1977	157.5	198.2	65.9	87.5	3.4
1978	172.5	211.4	83.3	93.9	3.6
1979	175.0	205.8	95.0	95.9	3.7
1980	210.5	234.7	106.4	99.2	3.8
1981	230.5	250.7	118.1	112.8	4.3
1982	257.0	257.0	104.5	104.5	4.0
Average Yearly Increase		7.1%		6.1%	

a/ High-volatile, non-coking bituminous, less than 10 mm in diameter from Ruhr coal mining area.
b/ Using Consumer Price Index.
c/ Using International MUV Index.
d/ On the basis of average calorific content of 11,780 Btu/lb.

Sources: European Economic Community; IMF (International Financial Statistics); IBRD (Report No. 814/82).

13/ For northern coastal areas, transport cost from ports is actually lower than from the Ruhr.

69. In the case of the power sector import quotas are associated with utilities agreement on a minimum take of domestic coal at prevailing prices and automaticity in the issuance of import licences in respect of a portion of requirements beyond pre-established levels when these arise out of substitution for oil and gas. In the industrial sector, incremental coal consumption and that resulting from coal for oil or gas conversion can be met with imported coal. In addition to these trade barriers, domestic coal producers ability to compete with imported coal and oil and gas is enhanced by a number of subsidies such as investment grants and, more importantly, special social security arrangements. According to a study carried out in 1978,[14/] total subsidies in 1976 (including an estimate of indirect social security-related payments) amounted to US$27 per tonne of hard coal produced (or about US$38 per tonne in 1982 dollars); lignite was not being subsidized significantly. LRMC were estimated at US$110 per tonne (and rising in real terms) for the kind of coal included in Table 4, and at US$95 per tonne for hard coal consumed by the power sector, both expressed in 1976 dollars (in 1982 dollars, the figures would be US$135 and 155 per tonne respectively). Although subsidies and LRMC are inflated by allocation of past costs to present and future production through allocation of some social security costs, LRMC still seems to fall in the US$110-130 per tonne range (in 1982 dollars) for even modest rates of capacity expansion (say 10% over the next 10 years). This is probably about twice as high as the CIF cost of imported coal.

70. Since it is cheaper, on the margin, to import rather than to produce coal domestically, an efficient policy would be to price coal in line with border (CIF import) prices (para. 34). The main objective of the current pricing and subsidy policies is to protect the domestic coal industry to (a) reduce dependence on imported energy and (b) generate employment. In order to assess the impact and costs of this policy, a brief description of the coal industry follows:

71. Coal is the major indigenous energy source of the FR of Germany. According to the 1978 World Energy Conference, technically and economically recoverable coal and lignite reserves were 24 and 10 billion tonnes respectively, although on account of the high costs encountered, the truly economically mineable reserves are but a portion of this, particularly in the case of hard coal. Indeed, geological and mining conditions for hard coal are difficult, so that without trade protection and subsidies perhaps only between a quarter and a third of the industry could survive, and only exceptionally could new mines be justified on economic grounds.

72. Domestic hard coal and lignite production in 1980-82 totalled respectively 90-95 million tonnes per year (mtpy) and 135 mtpy. About 10

14/ "Analysis of Steam Coal Prices in Six Member Countries of the OECD" (ICF Incorporated). Subsidies are not strictly comparable from country to country nor have remained at the same level over time. Therefore they provide only rough estimates.

mtpy (mostly coking coal) were exported (at a loss) and a similar tonnage (mostly steam coal) was imported. Coal meets about one third of total primary energy consumption; imported fuels (mostly oil) meet almost 60%. The bulk of the industry is in the hands of Ruhrkohle, which is partially Government-owned (in 1980-82 it produced 63 mtpy of hard coal, or almost 70% of the country's total).

73. Although two-tier pricing policy succeeds in keeping the domestic coal industry alive (total coal production has remained fairly stable since 1973), thus reducing reliance on imported energy (see para. 76 below) and safeguarding coal jobs, heavy economy-wide costs are incurred. First, consumers of domestic coal paid about US$30 per tonne more than they would have if coal were priced at border prices. For about 80 mtpy, this translates into an overpayment of about US$2.4 billion per year. With subsidies to the coal industry (direct and indirect) representing at least another US$500 million per year, each of the 60,000-90,000 direct underground jobs and perhaps 20,000-30,000 indirect jobs that could be lost without trade protection and subsidies[15/] cost more than US$26,000 a year to coal consumers and the Government.[16/]

74. Furthermore, it is not at all clear that the positive employment effect in coal mining of the current policies is larger than the negative employment effect in other industries. The extra cost of buying more expensive domestic coal for power generation is passed on to consumers in the form of a fuel levy. Since power is not for practical purposes a tradeable commodity, this does not affect power output much. However, inasmuch as power and direct coal consumption weigh heavily in some industries' costs, and with industry in general being open to external competition, highly-priced energy has a negative effect on industrial output and employment. Nowhere is this more marked and visible than in the steel industry, where coking coal is a major cost item, which is why the Government has been forced to provide coal usage subsidies (equivalent to the difference between domestic coking coal prices and CIF import prices into Europe) because domestic steel producers face stiff competition from foreign producers.

75. Another important cost arises in relation to suboptimal fuel choices and related investment decisions. Table 2 shows that until recently steam coal was not competitive with fuel oil and natural gas. This has acted as a break on the rational substitution of imported coal for

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15/ Total underground employment in coal mining in 1982 was about 120,000, with about 40,000 other jobs in the coal industry related to hard coal production. Perhaps one third to one half of total production and one fourth to one half of the jobs could resist competition unaided.

16/ There would be a counteractive cost to consumers resulting from international steam coal price increases due to higher German imports to replace lost domestic production. However, if import demand growth is spread over a number of years, this effect is believed to be small given that coal supply in major exporting countries such as South Africa and Australia appears to be highly elastic over the long run.

more expensive imported oil and gas, which counteracts the positive balance of payments effect of producing domestically rather than importing coal. The Government has sought to reduce the impact of possible uneconomic fuel choice decisions by prohibiting the construction of oil-or gas-based power plants and by generally allowing coal imports in the case of conversion projects. Still, a far more efficient way of creating employment would be, for example, to provide tax incentives or direct subsidies for jobs created in any industry either nationally or in coal regions. This could probably be achieved at lower cost per job and the fuel choice distortions would be reduced.

3. France

76. Steam coal prices in France also follow a "two-tier" system, similar to that of the FR of Germany; domestic coal is priced at (high) levels approaching production costs, while imported coal is priced in line with border prices (no significant duties or taxes apply). Table 1 shows a large margin between the two; domestic minehead prices were 50% higher than CIF import prices in 1980-82. Table 5 below gives details of average domestic mine-mouth steam coal prices, showing prices increasing almost without interruption over the 1973-82 period, but with two jumps in 1974 and 1980, when the Government took advantage of the energy crises and the growing competitiveness of coal in order to improve the financial position of the domestic coal industry.

Table 5: FRANCE - Average Minehead Steam Coal a/ Prices
(per tonne)

	Current FF	Constant 1982 FF b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu d/
1973	109.0	302.2	21.2	48.1	2.0
1974	160.0	371.7	33.2	55.3	2.3
1975	192.0	399.0	47.5	69.5	2.9
1976	209.0	397.7	44.7	64.4	2.7
1977	223.0	388.3	44.9	59.6	2.5
1978	240.0	382.7	52.1	58.7	2.4
1979	277.0	399.2	64.9	65.5	2.7
1980	419.0	532.5	91.9	85.7	3.6
1981	419.0	502.4	92.7	88.5	3.7
1982	542.0	542.0	79.4	79.4	3.3
Average Yearly Increase		6.7%		5.7%	

a/ High-volatile, non-coking bituminous, less than 10 mm in diameter, from Lorraine coal mining area.
b/ Using Consumer Price Index.
c/ Using International MUV Index.
d/ On the basis of average calorific value of 10,900 Btu/lb.

Sources: European Economic Community; IMF (International Financial Statistics); IBRD (Report No. 814/82).

77. Unlike Germany, however, no import quotas apply in France, with most consumers in the private sector actually resorting to imported coal: domestic coal is consumed largely by the public sector for power generation.

78. Although higher than border prices, domestic prices do not fully cover production costs. Therefore, government subsidies are required. These amounted to about US$40-50 per tonne in 1982-83, including direct operating subsidies and indirect (mostly social-security related) subsidies. The ICF Study mentioned above (para. 69) estimated 1976 direct and indirect subsidies of US$30 per tonne in prices of that year (about US$43 in 1982 dollars). LRMC were estimated at over US$100 per tonne in 1976 dollars, or US$150 in 1982 dollars. This is more than double the historic CIF import price of steam coal (see Table 1).

79. Since the cost of imported coal is lower than LRMC of domestic coal, coal pricing according to border (CIF import) prices would be in line with efficient criteria (para. 34). Such a policy would provide the right price signals to consumers (reflecting the marginal cost to the economy of supplying coal from the cheapest source) and to producers (indicating that only mines with LRMC lower than imported coal prices should be developed)and only mines with short-run marginal production cost below import parity should remain in operation.

80. The objectives of the present "two-tier" pricing policy and related Government subsidies are similar to those in the FR of Germany; i.e. to protect the domestic industry so as to reduce dependence on imported energy and generate employment (and also to stimulate development in coal producing regions). The French coal reserve base is very limited; 420 million tonnes of hard coal are technically and economically recoverable according to the 1978 World Energy Conference. Over the last few years, domestic production of hard coal totalled about 18 mtpy (of which somewhat less than 5 mtpy is coking coal and 3 mtpy anthracite) and about 3 mtpy of brown coal and lignite. Domestic coal meets less than 10% of total primary energy requirements. About 16 mtpy of steam coal and 10 mtpy of coking coal were imported in 1980-81. Coal is produced in France by a state-owned company, Charbonnages de France (CdF). Most domestic steam coal is consumed by CdF itself in its mine-mouth power plants (6-7 mtpy) or sold to another state-owned company, Electricite de France (EdF), for power generation. The French power sector is becoming increasingly nuclear based and, therefore, coal is expected to play a more modest role than in other countries' power systems.

81. Given that industrial consumers have access to imported steam coal, high domestic coal prices do not result in a direct cost to consumers. Electricity consumers do not seem to be directly affected either, as the Government in turn subsidizes the power sector; French

industrial power tariffs are among the lowest in Europe.[17/] This implies that consumer fuel choices involving steam coal are not distorted by protection of the domestic coal industry.

82. However, this protection is costing the Government, and indirectly consumers at large, about US$0.7 billion a year[18/] without including subsidies to EdF attributable to domestic coal cost. If all but a fourth of the domestic coal industry were to close down with elimination of CdF subsidies (involving perhaps 21,000 direct underground jobs[19/] and 6,000 indirect jobs), the cost to Government comes to over US$25,000 a job. When the indirect cost to the power sector is included (i.e. the difference between domestic and imported coal prices, say US$20 per tonne) the cost is estimated at over US$38,000 a job.

4. United Kingdom

83. Domestic steam coal prices in the UK are set by the National Coal Board (NCB), the state-owned company which is virtually the sole coal producer in the country, under the Government's oversight. The policy of the Government has been to encourage (a) coal consumption and coal for oil substitution and (b) domestic coal production primarily for employment and regional development considerations. Domestic prices (see Table 6) have therefore been set so as to be competitive with oil[20/] and, generally also with imported coal. Since the UK's coal industry enjoys a larger natural protection than the FR of Germany or France due to more favorable location of heavy energy consumers vis-a-vis domestic mines than ports, no significant trade protection is necessary, despite the fact that domestic minehead prices are higher than CIF import prices (Table 1). Also, over 80% of coal is consumed by other state-owned companies, and these have not

17/ At the beginning of 1981, the industrial rate (including taxes) for users consuming 106 MWh per year was US$.060/KWh in France, as compared to US$.075 in Germany, US$.068 in the UK, US$.076 in Italy and US$.095 in Holland. There are, of course, a myriad of factors aside from subsidies and coal costs affecting power costs and tariffs.

18/ At US$40 per tonne of hard coal produced, the Government decided in mid 1983 to put a cap on Government subsidies to CdF at FF 6.5 billion a year, but this figure includes social security transfers only in part related to current production.

19/ Total underground employment in 1982 was about 28,000.

20/ Table 2 shows that steam coal in the UK has enjoyed a more favorable price advantage vis-a-vis fuel oil (particularly for industry consumers) than in the FR of Germany and France. To encourage conversion the Government also offers investment grants to private industries gearing up for coal consumption.

been free to import coal.[21/] Domestic coal price movements from 1973 through 1982 are shown in Table 6.

Table 6: UNITED KINGDOM - Average Minehead Steam Coal a/ Price
(per tonne)

	Current L	Constant L b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu d/
1973	7.1	25.6	16.7	37.9	1.6
1974	10.3	30.4	24.7	41.1	1.8
1975	17.5	41.6	38.5	56.4	2.4
1976	20.0	40.8	38.0	54.7	2.3
1977	23.0	40.5	39.6	52.6	2.2
1978	25.3	41.2	46.1	52.0	2.2
1979	32.0	45.8	70.0	70.6	3.0
1980	43.6	53.0	93.1	86.8	3.7
1981	48.4	55.5	116.4	111.2	4.7
1982	52.5	52.5	91.5	91.5	3.9
Average Yearly Increase		8.3%		10.3%	

a/ High-volatile, non-coking bituminous, less than 10 mm in diameter from Yorkshire Coal Mining area.
b/ Using Consumer Price Index.
c/ Using International MUV Index.
d/ On the basis of average calorific value of 10,650 Btu/lb.

Sources: European Economic Community; IMF (International Financial Statistics); IBRD (Report No. 814/82).

84. In respect of private industrial consumers located close to ports, the NCB sometimes sells its coal at a discount as compared to delivered prices for other regions, regardless of transport costs. Steam coal imports into the UK have therefore been very modest, around one or two mtpy (para. 88).

85. However, given high production costs, Government subsidies to the NCB have been necessary in order to make domestic steam coal competitive. The ICF study mentioned in para. 69 estimated LRMC for power plant-quality steam coal at US$83 in 1976 dollars, or translating into about US$120 in 1982 dollars. Operating subsidies were estimated at some US$5 per tonne in 1976 dollars (US$7 per tonne in 1982 dollars). Subsidies are estimated to

21/ At present, the NCB and the Central Electricity Generating Board (CEGB) have an agreement that since NCB is on average (depending on location of power plants) more expensive than imported coal, the NCB will gradually reduce the price for the first 65 mtpy sold by yearly price adjustments that remain below inflation while sales above that will be priced at a discount reflecting international steam coal prices on a delivered basis.

have risen well above that for 1983, since international steam coal prices fell by US$10 per tonne or more as compared to 1982 and NCB is pricing coal at import parity in respect of a portion of the domestic market.

86. As a consequence of the disparity between domestic costs and international prices surpassing natural protection for growing regions of the country, a two-tier pricing system is arising (similar to that in France) where some NCB steam coal is sold to private industry and partially to the CEGB at prices in line with international quotations, while the rest (and still the bulk) is sold to public sector consumers at higher (non-competitive) prices.

87. The UK is a large coal producer, coming behind only eight other countries worldwide (US, China, USSR, Poland, the FR of Germany, South Africa, India and Australia) in terms of coal tonnage of standard quality coal. The 1978 World Energy Conference estimated its technically and economically recoverable reserves at 45 billion tonnes of hard coal. Although in consideration to the LRMC estimates above this figure seems to be overestimated, reserves are estimated to be the largest in Europe (excluding the USSR).

88. Production of hard coal (no lignite is produced) in the 1980-82 period was about 120-130 mtpy, of which about 10 mtpy is coking coal and three mtpy anthracite. Imports were between two and five mtpy (mostly coking coal) and exports about 8-9 mtpy (mostly steam coal). Exports have usually been made at a loss.

89. Setting domestic prices at CIF import levels appears to be an efficient pricing policy (a "hands off" policy could hardly work given NCB's position as a monopoly). The present pricing policy is geared primarily to generate employment, particularly in coal rich areas. Reducing dependence on imported energy is a less important factor in the UK given that it has become a net exporter of oil.

90. The cost of the present pricing and subsidies policies can be traced back to subsidies paid to the NCB and to the overpayment (as compared to delivered cost of imported coal) by public sector consumers such as the CEGB. The overpayment has not been as large as in the FR of Germany or France, and in some years it has been negligible. Also the subsidies per tonne produced are lower. However, since in contrast to LRMC (para. 85) short-run marginal production costs in the UK appear to be only slightly higher than border prices, eliminating the protection to NCB would probably result in modest loss of production and employment, suggesting a cost per job saved perhaps similar to that of France or Germany.

5. Japan

91. Coal prices are set in Japan according to a peculiar form of "two-tier" pricing policy. Domestic coal is priced based on Government-controlled negotiations between the numerous (private) consumers

and producers. Imported coal follows border prices (no significant charges such as duties arise). Government control or oversight is exercised in assuring that consumers buy domestic coal at prices that approximately cover full production costs. Since domestic coal production is costly due to difficult underground mining, this results in domestic coal prices higher than imports (domestic coal was about 40% more expensive than imported coal in 1980-82; see Table 1). The Government also seeks to spread the burden of high domestic coal prices evenly among consumers. Table 7 shows price movements for the last few years.

Table 7: JAPAN - Average Minehead Steam Coal a/ Prices
(per tonne)

	Current Y	Constant Y b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu d/
1976	13,080	17,675	44.1	63.5	2.7
1977	14,600	18,260	54.3	72.1	3.0
1978	15,030	18,107	71.4	80.4	3.4
1979	15,470	17,991	70.6	71.0	3.0
1980	17,050	18,355	75.2	70.1	3.0
1981	18,330	18,814	83.1	81.4	3.4
1982	19,400	19,400	77.9	77.9	3.3
Average Yearly Increase		1.6%		3.5%	

a/ Coal fines for power sector and general use.
b/ Using Consumer Price Index.
c/ Using International MUV Index.
d/ On the basis of average calorific value of 10,800 Btu/lb.

Sources: Ministry of International Trade and Industry (Japan); IMF (International Financial Statistics); IBRD (Report No. 814/82).

92. The main objective of the pricing policy is to reduce Japan's dependence on imported energy. Coal, the only domestic source of energy, represented only about 3.5% of Japan's total primary energy consumption in 1982).

93. Steam coal consumption in 1982 was 28 million tonnes, of which about half was imported and half supplied from domestic production. Consumption has been growing (it was only 13 million tonnes in 1979), with most of the growth met by imports. The power sector uses again about half the total steam coal supplied (about 15 million tonnes in 1982). Relative to other countries, steam coal consumption is still small. The country's power and industrial sectors were by and large oil-based, but steam coal's increasing competitiveness (see Table 2) plus Government incentives to convert to coal such as investment grants explain the recent demand upsurge.

94. According to the 1978 World Energy Conference, technically and economically hard coal reserves are about one billion tonnes, about half of which has some coking properties, especially on a blend basis. Geological and mining conditions are however quite difficult and such reserves thus appear overestimated. Production has been running at about 18 mtpy in the last couple of years, a growing share of which has been used as steam coal (given the marginal coking quality of Japanese coal, its end-use depends largely on relative availability and quality of imported coking coals for the domestic steel industry).

95. A hands-off pricing policy would be more efficient. The present policy entails economic costs in inefficient production. The coal industry enjoys Government subsidies in the form of development grants and cheap financing. No estimates are available on the size of these subsidies, but they are believed to be smaller per tonne produced than in the Western European countries discussed above. However, together with the overpayment by consumers (about US$30 per tonne on average in 1980-82 as compared to imported coal),[22/] the economic cost is unlikely to be less than US$35 per tonne, or of a similar order of magnitude as in Europe.

C. DEVELOPING COUNTRIES

1. South Africa

96. South African coal is marketed under a "two-tier" pricing policy which is altogether different from that of Western Europe and Japan. South Africa is a major coal exporter and its coal industry, which is totally private, produces at low cost. Since FOB export prices (about US$35 per tonne on average in 1981) have been higher than LRMC, export coals generate a substantial economic rent (para. 40). Coal for the domestic market is sold at much lower prices, in line with either Government-set price lists or with prices determined by bids for long-term coal supply contracts invited for by the state-owned power company at the time it decides the location of its mine-mouth power plants. Government-set prices seek to cover LRMC to encourage expansion of the coal industry. Table 8 includes South African mine-mouth domestic steam coal prices for the 1973-82 period, which after increasing rapidly immediately after the 1973 energy crisis, stagnated or even fell in real terms in later years as adjustments failed to keep pace with inflation. As seen in Table 1, these prices are among the lowest worldwide.

22/ Virtually all coal in Japan is produced in the northern island of Hokkaido or the southern island of Kyly. Transportation from mines to most consumers is therefore more costly than from ports of entry of imported coal to the same consumption centers.

Table 8: SOUTH AFRICA - Average Minehead Steam Coal Prices
(per tonne)

	Current Rand	Constant Rand a/	Current US Dollars	Constant 1982 US dollars	Constant 1982 US$ per million Btu b/
1973	2.5	7.2	3.6	7.5	0.3
1974	3.4	8.9	5.0	8.3	0.3
1975	4.5	10.5	6.2	9.1	0.4
1976	6.8	14.2	7.8	11.2	0.5
1977	7.0	13.2	8.1	10.7	0.4
1978	7.7	13.0	8.8	9.9	0.4
1979	8.6	12.9	10.2	10.3	0.4
1980	9.6	12.7	12.3	11.5	0.5
1981	10.8	12.4	12.4	12.1	0.5
1982	12.2	12.2	11.3	11.3	0.5
Average Yearly Increase		6.0%		4.7%	

a/ Using Consumer Price Index.
b/ On the basis of average calorific value of 11,700 Btu/lb.

Sources: Transvaal Coal Owner Association; IMF (International Financial Statistics); IBRD (Report No. 814/82).

97. To avoid producers moving to the much more lucrative export business to the detriment of domestic consumers, export quotas are established. The present quotas stand at 44 mtpy, but have been lifted to 70 mtpy for later in the 1980s.

98. The objectives of these Government pricing and trade policies are: (a) to give priority to the satisfaction of domestic energy requirements (coal meets more than 70% of total South African primary energy consumption) at a reasonable cost; (b) to allow an acceptable return on capital invested to provide incentives for expansion; and (c) to avoid reaching a level of coal exports which would drive international prices down to South Africa's LRMC, which would substantially reduce the economic rent that accrues to the country.

99. Given the already predominant position of South Africa in the steam coal market (in 1981 it captured about one fourth of the world's trade), and the resistance of importers to heavy reliance on one supplier, further increases in South Africa's share probably could come only with significant price discounts. The Government's commercial strategy thus has a rational economic foundation (para. 40).

100. With export quotas in place, the question arises whether a "hands-off" pricing policy or border pricing in respect of the domestic market would not be more efficient than LRMC pricing. Also, whether (in any case) a depletion or resource rent should not be added to LRMC to set domestic prices in line with the true cost to the economy (para. 16).

101. Turning to the second question first, according to the 1978 World Energy Conference, South Africa's technically and economically recoverable reserves are estimated at about 27 billion tonnes of hard coal, almost all steam coal. In contrast to the estimates for Japan and Western Europe, in this case recoverable reserves seem underestimated, and the Government recently put such reserves at over 57 billion tonnes. Given that these reserves would stretch for hundreds of years at present production rates, the depletion or resource rent factor lacks practical significance.

102. The first question requires a somewhat more elaborate analysis. Coal production in South Africa totalled about 130 million tonnes in 1981, up from about 70 million tonnes in 1975. Exports in 1975 and 1982 totalled about three and 26 million tonnes respectively. Geological and mining conditions are very favorable and LRMC are therefore low (both for underground and open pit mining). However, there are extra costs associated with coal production for export. Export quality coal requires difficult and costly washing,[23/] but still LRMC is estimated at only about US$25-30 per tonne FOB port of shipment (or about US$20 per tonne at the mine-mouth), according to a recent study carried out for the World Bank by specialized consultants.

103. Domestic coal subject to Government-set prices has been sold at below the LRMC for export quality coal (the average price for 1982 in Table 8 is only US$11 per tonne). However, since the domestic market does not impose by and large the same quality requirements, coal for domestic use can be produced at a lower cost, so that except for the last couple of years when domestic prices in 1982 Rand fell somewhat, they appear to have covered LRMC. The industry as a whole and even non-exporting mines show satisfactory financial results.

104. South African coal seams vary significantly in quality; as a consequence, a variety of coals are produced in most mining operations. Since the bulk of the domestic market is represented by mine-mouth power plants capable of taking low-quality coal, no washing is necessary to supply such plants. But also in the case of mines exporting coal, the domestic market allows them to: (a) mine a larger number of coal seams thus increasing extraction and recovery rates and reducing unit costs (in the case of open pit mines, lower quality coal extracted would otherwise be discarded as waste); and (b) in the process of washing, most of the calories otherwise discarded in the refuse can be captured in middlings to be burned by power plants. The economic cost of producing domestic coal is therefore lower than producing export coal. At the same time, the export

23/ South African coal is high in ash and does not wash easily.

market has not only provided a financial boost to the mining industry, but also has contributed to reduce LRMC for low quality coal consumed domestically.

105. Pricing domestic coal at border prices (even using a correction factor to account for quality and cost differences) would not be a more efficient policy than LRMC pricing; given the trade policy considerations made above, the opportunity cost of domestic coal is given by the pertinent LRMC. Since there is a large number of producers and consumers, a "hands-off" policy in respect of domestic prices coupled with export quotas would appear to be the most adequate policy, but as long as the Government sets prices that generate sufficient incentives for mine expansion (i.e. cover LRMC for the pertinent qualities), actual prices and economic results are not likely to be too different under either policy over the long run.

2. Zimbabwe

106. In Zimbabwe there is only one coal producer, Wankie Colliery Ltd. (WCL), a majority foreign-owned (the Government has a small equity participation) and foreign-controlled company. WCL produces some 3.2 mtpy, mostly coking coal, although steam coal production is scheduled to rise sharply on completion of an expansion program now underway. Some coal is exported to neighboring countries. Since WCL is a monopoly, coal prices are Government controlled. Prices are established with the objective of allowing WCL to earn an after-tax return of 12.5% on its capital employed. This roughly reflects LRMC; WCL can expand its production capacity without necessarily incurring higher unit costs. If strictly adhered to, the pricing policy would provide incentives to WCL to expand in line with demand growth. However, for years now price adjustments have lagged behind cost increases. This does not show clearly in Table 9 shown below, which points to real price increases in 1980-82, but the latter years coincided with very large Government-decreed wage adjustments so that WCL costs rose faster than inflation.

Table 9: ZIMBABWE - Average Minehead Steam Coal a/ Prices
(per tonne)

	Current Z$	Constant 1982 Z$ b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu
1973	2.7	6.4	4.6	9.6	0.3
1974	3.2	7.0	5.7	9.5	0.3
1975	5.1	10.3	9.2	13.5	0.5
1976	5.4	9.9	8.6	12.4	0.4
1977	6.0	10.0	9.6	12.7	0.5
1978	6.5	9.9	9.6	10.8	0.4
1979	6.8	9.1	10.0	10.1	0.4
1980	7.6	9.6	11.8	11.0	0.4
1981	9.0	10.1	13.0	12.7	0.4
1982	11.4	11.4	15.0	15.0	0.5
Average Yearly Increase		6.6%		5.1%	

a/ Dry, unwashed coal supplied to power plants.
b/ Using Consumer Price Index.
c/ Using International MUV Index.

Sources: Wankie Colliery Company Ltd.; IMF (International Financial Statistics); IBRD (Report No. 814/82).

107. The present pricing policy also provides the right signals to consumers. Since WCL is a low-cost producer coal prices are among the lowest worldwide (see Table 9 and Table 1). Domestic coal prices are therefore very competitive with oil, which due to high transportation charges is extremely costly in the country. As a result there is a strong incentive for consumers to use coal; Zimbabwe already relies heavily on coal (45%) and hydropower (40%) and only about 15% on imported oil to meet commercial energy needs. Coal reserves are abundant; technically and economically recoverable reserves were estimated at 755 million tonnes by the 1978 World Energy Conference.

108. It can reasonably be argued that a cost-plus pricing formula such as the one used in Zimbabwe breeds inefficiency. The question is how to provide incentives to keep costs low. Where producers are public sector companies, which in principle are not profit-motivated, strict Government control and productivity-related bonuses to managers might be adequate. In the case of private companies, such as WCL, a sliding-scale price formula related to pre-established efficiency goals would appear worthwhile exploring.

3. Argentina

109. Domestic steam coal prices in Argentina are set by the Government through Yacimientos Carboniferos Fiscales (YCF), a state-owned company and sole coal producer in the country. There is virtually no trade in coal

(minor tonnages have been exported from time to time). Prices seek to make coal competitive with oil, and a cap has been put on delivered prices so that they do not surpass 70% the price of fuel oil. After the 1979 oil price increase, this cap remained way above the CIF price of imported coal. But although such a cap would have allowed YCF coal to be priced to cover all costs, actual prices have lagged behind and YCF has had to be subsidized. Domestic coal is transported over 200 km by rail to port in the extreme south of the country (Rio Gallegos) and from there 2000 km by coastal shipping to the consumption centers at Buenos Aires. Because of the high transport costs, netback mine-mouth prices have been low (see Table 1 and Table 10). Delivered prices have been several times higher than mine-mouth prices, but still below international prices. Without subsidies, however, YCF would at times not have been competitive with imported coal.

110. The objectives of the pricing and subsidy policy have been to generate economic activities and employment in an underdeveloped region of the country and to encourage use of coal over fuel oil particularly in power generation. With the erratic movement of real coal prices (a result of triple-digit inflation), subsidies have also varied wildly.

Table 10: ARGENTINA - Average Minehead Steam Coal Prices (per tonne)

	Constant 1982 A Pesos	Current US$	Constant 1982 US$	Constant 1982 US$ per million Btu a/
1973	80	8.5	17.7	0.7
1974	260	8.8	14.7	0.6
1975	148	3.5	5.1	0.2
1976	152	5.1	7.3	0.3
1977	176	5.6	7.4	0.3
1978	172	7.6	8.6	0.4
1979	175	12.2	12.3	0.5
1980	172	17.3	16.1	0.7
1981	145	12.4	12.1	0.5
1982	242	9.4	9.4	0.4
Average Yearly Increase	13.1%		-6.8%	

a/ On the basis of 11,100 Btu/lb.

Sources: Yacimientos Carboniferos Argentinos; IMF (International Financial Statistics); IBRD (Report No. 814/82).

111. Production totals only about 0.6 mtpy of steam coal with high ash content which through washing is brought to acceptable ash levels. Technically and economically recoverable reserves were estimated at 290 million tonnes by the 1978 World Energy Conference. YCF is currently

exploring in the already established mining area to determine whether larger production at reasonable cost could be obtained so as to expand transport infrastructure and thus reduce delivered costs. Mining conditions are not too difficult and LRMC of both mining and transportation could come down in the future to make domestic coal competitive with both fuel oil and imported coal.

112. To provide the correct signals to YCF and to consumers, pricing according to LRMC would be an efficient policy. It is recognized however, that it is not easy to determine LRMC given the proportionally large expansion possibilities of both the coal mining industry and of the related infrastructure. Should LRMC surpass coal import prices, and the Government nevertheless decided to expand the domestic coal industry, a border pricing policy and subsidies to YCF would be called for, so that the Government as a whole rather than coal consumers shoulders the burden of protecting an activity justified for other than economic reasons.

4. Brazil

113. Steam coal prices in Brazil are set by the Government. Despite large price increases in 1981 and 1982 (Table 11), the situation is similar to that of Argentina; i.e., coal prices do not cover production and transportation costs so that Government subsidies arise (para. 115). The coal pricing policy seeks to promote coal consumption and specially substitution for imported fuel oil, by making the delivered price of coal competitive with fuel oil (coal is to cost on a delivered basis not more than 70% the value of fuel oil), and to promote mine development, by establishing minehead prices that allow mining companies to earn a real 20% return on their investment.

114. Brazil's technically and economically recoverable reserves of hard coal and brown coal are estimated at 2.5 and 5.6 billion tonnes respectively. Coal is produced by numerous private miners. Output in 1981 was about six mtpy, of which coking coal was about one sixth. No steam coal is traded; coking imports ran at about five million tonnes in 1981. Coal meets about 5% of total primary energy. Oil imports weigh heavily in Brazil trade accounts, representing some 40% of total merchandise imports in 1980.

Table 11: BRAZIL - Average Minehead Steam Coal a/ Prices
(per tonne)

	Current Cr	Constant 1982 Cr b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu d/
1973	93	4916	15.2	31.7	1.8
1974	107	4432	15.7	26.1	1.5
1975	147	4725	17.9	26.2	1.5
1976	197	4459	18.5	26.6	1.5
1977	278	4380	19.7	26.2	1.5
1978	403	4578	22.3	25.1	1.5
1979	652	4851	24.2	24.4	1.4
1980	1153	4692	19.0	17.7	1.0
1981	3135	6207	33.7	33.0	1.7
1982	7020	7020	39.1	39.1	2.2
Average Yearly Increase		4.0%		2.4%	

a/ Non-coking bituminous coal from Leao.
b/ Using Consumer Price Index.
c/ Using International MUV Index.
d/ On the basis of a calorific value of 7920 Btu/lb.

Sources: Brazil, Ministry of Mines and Energy; IMF (International Financial Statistics); IBRD (Report No. 814/82).

115. Since mining and transport costs are too high to allow for both objectives to be met without Government support, a state-owned company (CAEEB) buys all the coal at differential prices depending on the costs prevailing in various coal basins or regions and delivers and sell the coal at a loss. These losses amounted to about US$100 million in the first half of 1982, or about US$30 per tonne.

116. Domestic coal has actually been sold to final consumers cheaper than fuel oil and also at times cheaper than CIF import prices. Without subsidies, imported coal could be cheaper than domestic coal in certain regions of Brazil. However, with feasible improvements in mining efficiency and transport infrastructure (the bulk of the coal is produced in the extreme south of the country and transported long distances), in the long run domestic coal could be generally competitive with imports. LRMC for domestic coal production can probably be kept close to import parity over the next 10 years, with production increasing to about 25 mtpy. Although coal quality is generally low due to high ash content, mining conditions are favorable and reserves abundant (2.2 billion tonnes of proven reserves). Production is planned to grow from 5.7 million tonnes in 1981 to more than twice that amount in 1985.

117. While the objective of promoting consumption has been realized, the cost to Government finances is huge. Also the policy has bred inefficiency among producers, as CAEEB purchase prices are adjusted to

actual costs in different areas, and there are few incentives for producers to cut their costs or to value potential deposits in different areas according to their relative economic merits.

118. In Brazil there are numerous coal producers and consumers. A hands-off pricing policy coupled with free access to imported steam coal and development of efficient transport infrastructure serving the mining regions would therefore be possible and economically more efficient. Such a policy would provide consumers with sufficient incentives to rely on coal rather than fuel oil in many uses (provided fuel oil is priced domestically in line with international prices) and would still provide incentives for development of the domestic coal industry, although forcing upon it improvements in operational efficiency and in the choice of investment projects.

119. If price controls are to continue, pricing of domestic coal at the quality-adjusted coal import parity, and not the fuel oil parity, would have advantages over the present policy. It would virtually eliminate the need for subsidies and provide mining companies and consumers the right production and investment and fuel choice signals.

5. Colombia

120. Coal prices in Colombia are freely set by market forces, making it an exception among developing countries. There are more than 400 coal operations, widely spread regionally over central and southern Colombia, producing some five mtpy of high quality coal. In the past decade, production grew quite rapidly (at about 7% per year), to meet about 20% of total commercial energy requirements in 1982. Technically and economically recoverable reserves were estimated at about 400 million tonnes of hard coal by the 1978 World Energy Conference. However, recent exploration has already increased estimates of such reserves to over three billion tonnes. Production is scheduled to reach over 20 mtpy by the end of this decade.

121. Coal prices advanced rapidly in real terms, at over 6% per year between 1973 and 1982 in Col$ or over 10% in US dollars (Table 12). Most of the increase took place in 1977 and 1978, as a reflection of rapid demand growth principally by power plants and industry, in part due to large fuel oil price advances in the previous years. Also, there is an underlying upward cost trend as mines in central Colombia deepen and reserve blocks become more difficult to access. Still, coal prices at the mine level remain at about US$20 per tonne (among the lowest in the world, see Table 1) and delivered prices at less than US$30 per tonne on average, due to the relatively short distances involved between mining areas and main consumption centers.

Table 12: COLOMBIA - Average Minehead Steam Coal Prices a/
(per tonne)

	Current Col$	Constant 1982 Col$ b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu d/
1973	93	667	3.9	8.1	0.3
1974	113	665	4.2	7.0	0.3
1975	153	723	4.9	7.2	0.3
1976	193	758	5.6	8.1	0.3
1977	315	930	8.6	11.4	0.5
1978	468	1173	12.0	13.5	0.5
1979	565	1136	13.3	13.4	0.5
1980	726	1153	15.4	14.4	0.6
1981	963	1199	17.7	17.3	0.7
1982	1266	1266	19.8	19.8	0.8
Average Yearly Increase		7.4%		10.4%	

a/ Average for Central Colombia.
b/ Using Consumer Price Index.
c/ Using International MUV Index.
d/ On the basis of average calorific value of 11,200 Btu/lb.

Sources: Carbones de Colombia, S.A.; IMF (International Financial Statistics); IBRD (Report No. 814/82).

122. Even though domestic coal prices are much lower than international prices and the quality of the coal mined is good, coal exports have been small. This is explained by long distance and high transport cost from the presently developed mining areas to the northern export outlets (about US$30 per tonne), which act as natural barriers to trade and have made coal consumption on the northern coast expensive and therefore a rarity. However, coal developments along the northern coast now underway will open the way for catering for exports and for the domestic market in that region.

123. The Government has seen no need to intervene in the domestic coal market given the fact it this has been quite competitive: producers and consumers are numerous and so are the suppliers of transport services (mostly trucks). No significant monopolistic or monopsonistic forces are at play, with prices providing the right signals in terms of economic cost and investment opportunities to consumers and producers.

6. India

124. Coal prices in India are set by the Government at the mine-mouth; consumers pay the transportation cost. As seen in Table 1, Indian domestic steam coal prices at mine-mouth have traditionally been among the lowest worldwide. Table 13 also shows that it is only in the last few years that

prices in Rs. have risen significantly in real terms. Until recently the overriding concern was centered on lowering costs to coal consumers, thus promoting coal for oil substitution and controlling inflation (coal is one of the country's most important commodities). The result was that producers could not cover LRMC; by the late 1970s, prices were not even covering cash operating costs. Government subsidies were therefore required; in 1978-79 Coal India Limited (CIL), the largest Government coal company, incurred losses of Rs 2.4 billion on sales of Rs 5.4 billion.

125. Virtually all coal output is in fact in the hands of the Government; CIL accounts for 90% of production, and other state-owned companies for much of the remainder. Coal currently represents about 55% of India's total commercial energy supply. Oil represents 33% of the total, but given that over half of it is imported the burden of this fuel in the trade balance is highlighted by the fact that in 1981-82 oil imports amounted to about US$6 billion, or over 70% of merchandise export earnings. India possesses large coal reserves and is a major coal producer. According to the 1978 World Energy Conference, technically and economically recoverable reserves were estimated at over 33 billion tonnes of hard coal and 350 million tonnes of brown coal. Production in 1982-83 was about 130 million tonnes (of which 30 million were of coking quality), up from 73 million tonnes in 1970.

126. Trade in coal is quite limited; India occasionally exports minor amounts of steam coal and imports about 0.5 mtpy of coking coal. Although steam coal mining costs are among the lowest worldwide, the quality of the product is also low, so that it is not directly tradeable (the bulk of steam coal deposits are in the 6,000-8,000 Btu/lb range and ash content in the 26-32% range). Technically the low quality coal can be considered as indirectly tradeable since it is a substitute for tradeable fuels (mainly higher grade steam coals). However, since domestic coal has substituted for virtually all other fuels wherever economically feasible (so that on the margin it is not indirectly tradeable) and since LRMC of coal production falls between CIF import prices and FOB export prices (when adjusted for quality and transport costs), an efficient pricing policy would set coal prices at LRMC. No reserve rent arises in view of the magnitude of economic reserves.

Table 13: INDIA - Average Minehead Steam Coal Prices
(per tonne)

	Current Rs.	Constant 1982 Rs. a/	Current US$	Constant 1982 US$ b/	Constant 1982 US$ per million Btu c/
1973	43	86	5.6	11.7	0.6
1974	48	75	5.9	9.8	0.5
1975	56	83	6.7	9.8	0.5
1976	64	112	7.1	10.2	0.5
1977	64	104	7.3	9.7	0.5
1978	64	105	7.8	8.8	0.4
1979	85	116	10.5	10.6	0.5
1980	105	128	13.4	12.5	0.6
1981	132	142	15.2	14.9	0.7
1982	151	151	16.0	16.0	0.8
Average Yearly Increase		6.5%		3.5%	

a/ Using Consumer Price Index.
b/ Using International MUV Index.
c/ Based on average calorific value of 9,500 Btu/lb.

Sources: Coal India Limited; IMF (International Financial Statistics); IBRD (Report No. 814/82).

127. A new coal pricing policy was established in the early 1980s; it is based upon the principle of CIL recovering the full cost of production, subject to satisfactory operating performance, and also allowing for a return on assets. This is a case of "average cost" pricing (para. 28), and is in line with pricing policies proposed by the Bureau of Public Enterprises for various commodities. The objective of the policies are for prices to reflect the true cost to the economy and to ensure financial viability of, and the capability to expand productive capacity by, the coal industry. As seen in Section II.B of this study, average cost pricing breeds inefficiency among producers since they do not have a clear incentive to minimize costs. The Indians introduced an interesting feature by trying to deal with this problem by setting operational norms for each of CIL's subsidiaries and establishing internal reference or retention prices against which performance is judged. This system is however difficult to administer and requires frequent updating of operational norms to work.

128. Following recent price increases, a further increase of about 20% in real terms has taken place, leading to price levels which are approaching LRMC. This has also improved considerably resource mobilization within the sector.

7. Philippines

129. Coal prices in the Philippines are set by market forces, although the Government policy can not quite be described as "hands-off" type (para. 23), since it has established floor and ceiling prices. The floor prices (approximately US$54 per tonne of coal delivered) is based on one long term coal supply contract in the country. The ceiling is established on the basis of the (higher) import parity price of coal, although in the case of the cement industry the ceiling is 65% of the fuel oil price on a heat-equivalent basis. Within floor and ceiling, however, producers and consumers can negotiate freely.

130. The objectives of this policy are to eliminate for consumers and producers some of the uncertainties of market prices that might inhibit investments in coal mining or consumers' motivation to convert to coal. The Government assures import of coal when prices reach the ceiling. As seen in Table 14 below, domestic coal prices moved closely with international fuel prices following the 1973 and 1979/80 energy crises. Coal prices in 1974 and the early eighties increased markedly.

Table 14: PHILIPPINES - Average Minehead Steam Coal Prices
(per tonne)

	Current Pesos	Constant 1982 Pesos a/	Current US$	Constant 1982 US$ b/	Constant 1982 US$ per million Btu c/
1973	75	236	11.1	23.2	1.1
1974	150	352	22.1	36.8	1.7
1975	158	343	21.7	31.8	1.4
1976	160	327	21.5	31.0	1.4
1977	180	341	24.3	32.3	1.5
1978	170	300	23.1	26.0	1.2
1979	195	289	26.4	26.6	1.2
1980	270	340	36.0	33.6	1.5
1981	340	383	43.0	42.1	1.9
1982	378	378	44.2	44.2	2.0
Average Yearly Increase		5.4%		7.4%	

a/ Using Consumer Price Index.
b/ Using International MUV Index.
c/ At average calorific value of 10,000 Btu/lb.

Sources: Philippines National Coal Authority; IMF (International Financial Statistics); IBRD (Report No. 814/82).

131. The largest single coal producer is a state-owned company, Philippine National Oil Company (PNOC), but there are a number of smaller producers. PNOC also has the monopoly of imports. Coal consumption is

expected to reach 3 mtpy in the late 1980s, from less than 0.5 million in 1981. In 1981 coal represented only about 1% of total commercial energy consumption, and a sizeable increase in this share is promoted by Government. Imported oil now accounts for over 80% of its commercial energy supplies and coal, domestically produced or imported, can substitute part of it.

132. The 1978 World Energy Conference does not provide coal reserve estimates for the Philippines. In 1982 proven coal reserves (not necessarily economically recoverable) stood at 175 million tonnes. Coal production in 1982 was only 0.56 million tonnes.

133. The pricing policy appears to be economically efficient, although distortions have emerged due to the decline in international prices which began in 1982.

8. Thailand

134. Energy products remained generally under-priced as compared to international prices up to 1979. Since then, substantial domestic price increases took place. Oil now follows international quotations. In the case of lignite (no hard coal is produced), the increase up to 1982 was 50% in constant Baht (see Table 15 below). The current policy is a typical average cost pricing case (see para. 28) under which lignite is to be priced so as to yield the Electricity Generating Authority of Thailand (EGAT), the state-owned company accounting for 90% of the lignite supply, a reasonable financial rate of return on its mining investments after covering its production costs. As seen below, this in Thailand is consistent with efficiency pricing.

Table 15: THAILAND - Average Minehead Lignite Prices (per tonne)

	Current Baht	Constant 1982 Baht a/	Current US$	Constant 1982 US$ b/	Constant 1982 US$ per million Btu c/
1979	188	267	9.2	9.3	0.9
1980	244	289	11.9	11.1	1.0
1981	318	335	14.6	14.3	1.3
1982	410	410	17.8	17.8	1.7
Average Yearly Increase		15.4%		24.2%	

a/ Using Consumer Price Index.
b/ Using International MUV Index.
c/ Based on average calorific value of 2,700 kcal/kg.

Sources: Electricity Generating Authroity of Thailand; IMF (International Financial Statistics); IBRD (Report No. 814/82).

135. No coal reserve estimates for Thailand were provided by the 1978 World Energy Conference. According to Thai estimates, reserves are about 850 million tonnes of lignite. No economic hard coal reserves are known. Lignite output increased from 0.6 to 1.7 mtpy from 1978 to 1982. In the latter year, 90% of it was consumed for mine-mouth power generation, as lignite's high moisture and ash content makes it too costly to transport over long distance.

136. Given that lignite is not directly tradeable, but substitutes for tradeable commodities (the cheapest alternative to domestic lignite appears to be imported steam coal) the domestic price of lignite should reflect the quality- and transport-adjusted CIF import price of steam coal (para.13).

137. Based on a recent lignite pricing study carried out in Thailand (see Annex 1), it was established that the present lignite policy results in prices which are in line with efficiency prices (coal import prices). Also, current prices roughly cover LRMC. Since it is practically equally costly to produce lignite or import coal, no scarcity rent arises despite lignite's limited reserves. In Thailand, therefore, there is a curious coincidence: current prices set on the basis of financial considerations are not only similar to LRMC but also to the border price of the pertinent substitute, implying an equilibrium situation.

9. Morocco

138. Coal prices in Morocco are set by the Government for all coal produced by Charbonnages du Maroc (CdM). CdM is a state-owned company and is the single producer in the country, at a single location, Jerada. As Table 16 below shows, domestic steam coal prices remained quite stable in real terms up to 1980; in 1981 and 1982 they increased rapidly. Still, prices in these two years (about US$40 per tonne on average) did not cover unit production costs (US$50 per tonne) because of cost increases and CdM continued incurring losses which made Government subsidies necessary. These have taken the form of equity contributions, non-payment of social security charges, etc.

Table 16: MOROCCO - Average Semi-Anthracite Minehead Coal Prices
(per tonne)

	Current DH	Constant 1982 DH a/	Current US$	Constant 1982 US$ b/	Constant 1982 US$ per million Btu c/
1973	58	145	14.1	29.4	1.4
1974	78	166	17.8	29.6	1.4
1975	78	154	19.2	28.1	1.3
1976	90	164	20.4	29.4	1.3
1977	103	167	23.0	30.6	1.4
1978	103	152	24.7	27.8	1.3
1979	115	156	29.5	29.8	1.4
1980	128	159	32.5	30.3	1.4
1981	197	218	38.1	37.3	1.7
1982	242	242	40.2	40.2	1.8
Average Yearly Increase		5.9%		3.5%	

a/ Using Consumer Price Index.
b/ Using International MUV Index.
c/ On the basis of average calorific content of 9,900 Btu/lb.

Sources: Charbonnages du Maroc; IMF (International Financial Statistics); IBRD (Report No. 814/82).

139. The objective of Government policy is to promote use of coal in preference to oil (imported oil has in the past represented over 80% of total commercial energy consumption while coal meets about 7%-10% of commercial energy consumption) and thus, to keep coal prices as affordable as possible to consumers. With this objective in mind the Government has over the past few years kept sales prices for Jerada coal intentionally low thus creating not only an increasing gap between local coal prices and prices for imported coal but also a shortfall between average coal prices and production unit cost which resulted in operational losses for CdM. After 1982, however, the looming financial difficulties of CdM along with substantial efforts by a new management team convinced the authorities of the necessity of a more rationale pricing policy. This resulted in a series of successive price adjustments which by April 1984 brought prices for Jerada coal close to import parity and introduced a margin of about 20% over CdM's unit costs. Prices in 1983 ranged between US$47-50/tonne declining to less than US$45/tonne by mid-1984, principally due to exchange rate developments.

140. Morocco's case is to some extent comparable to that of Brazil and Argentina, where concern for substituting coal for oil has depressed the price for domestic coal below both LRMC and the border price for the cheapest fuel alternative (normally imported steam coal). Mining conditions in Morocco are difficult, but LRMC at Jerada, the only mine in operation, are estimated to remain competitive on a quality adjusted basis

with imported steam coal,[24/] at least for consumption centers located near Jerada, in the eastern part of Morocco.

141. Until recently imported coal was subject to import duties. Imports have therefore been modest (of the order of 20,000 tonnes per year). Recently, however, import duties were eliminated to provide incentive for oil to coal substitution, principally in electricity, sugar, and cement production (additional to the incentive resulting from the already existing price difference between oil and coal).

142. The reserves of the Jerada deposit are estimated at 10 million tons of measured reserves and about 20-30 million tons of possible reserves. 1982 production was 735,000 tonnes. LRMC at Jerada appear to fall between export parity and import parity prices for the eastern part of the country. Therefore, an efficiency pricing objective would be to bring Jerada coal prices in line with import parity; this would provide a sound financial basis for CdM while maintaining competitiveness of Jerada coal in the eastern areas. It would, however, not provide any incentive for an increase in production over one million tpy which is considered the long-term limit from the technical and managerial point of view. Consumers in western Morocco would find it cheaper to import coal in consideration of high transport cost from Jerada. However, since CdM's markets are mainly located in the east, where demand exists for most of its production, only small quantities would be available anyhow for clients in the west. Coal prices on the western coast should therefore follow CIF import prices.

10. Turkey

143. Historically, coal and lignite prices in Turkey have been low compared to production costs and to international coal prices. Low prices are believed to have encouraged waste among consumers as well as shortages. The bulk of domestic coal and lignite output is in the hands of Turkiye Komur Isletmeleri Kurumu (TKI) a state-owned enterprise. Despite real price increases since 1978 (see Table 17 below), Government subsidies to TKI have been required uninterruptedly. The current coal and lignite pricing policy (established since 1980, but in part following earlier trends) seeks to gradually eliminate subsidies to TKI and to bring domestic coal and lignite prices in line with the heat- and quality-adjusted price of imported fuel oil.

24/ Jerada produces semi-anthracite which is mostly used for power generation. Minor amounts of it (up to 30,000 tonnes per year) have been exported.

Table 17: TURKEY - Average Minehead Lignite Prices
(per tonne)

	Current TL	Constant 1982 TL a/	Current US$	Constant 1982 US$ b/	Constant 1982 US$ per million Btu c/
1973	90	1,567	6.4	13.3	1.0
1974	90	1,353	6.5	10.8	0.8
1975	90	1,134	6.2	9.1	0.7
1976	90	990	5.6	8.1	0.6
1977	143	1,238	7.9	10.5	0.8
1978	370	2,205	15.2	17.1	1.3
1979	650	2,441	20.9	21.1	1.6
1980	1,440	2,573	18.9	17.6	1.3
1981	2,150	2,813	19.3	18.9	1.4
1982	2,870	2,870	17.7	17.7	1.4
Average Yearly Increase		7.0%		3.2%	

a/ Using Consumer Price Index.
b/ Using International MUV Index.
c/ Based on an average calorific value of 5,900 Btu/lb.

Sources: Turkish Coal Enterprise; IMF (International Financial Statistics); IBRD (Report No. 814/82).

144. The 1978 World Energy Conference estimated technically and economically recoverable reserves of hard coal and lignite at 130 million and 660 million tonnes respectively. Mining conditions for hard coal are however difficult and it is doubtful whether that amount can be economically exploited. 1982 output of lignite and hard coal was respectively about 18 and four million tonnes, all but two million tonnes of lignite produced by TKI. Coal and lignite currently meet about 30% of total primary energy consumption (as compared to over 50% for imported oil).

145. Domestic hard coal prices (not included in Table 17) have recently surpassed CIF import prices of comparable coal while TKI would still not cover its full costs. In contrast, lignite can be exploited economically and plays a more important role; thus it receives greater attention here. Lignite is not directly tradeable, but, indirectly, it substitutes for imported fuels (hard coal). Current policies have brought prices more in line with economic criteria. Subsidies per tonne of lignite have been cut from US$25 per tonne in 1978 to US$2.5 per tonne in 1982 as prices in constant TL have risen steadily since the late seventies. Currently lignite prices are only about 25% (on a heat-equivalent basis) the level of imported fuel oil. However, the objective of setting lignite prices based on fuel-oil parity does not provide an appropriate opportunity cost; the quality-adjusted price of imported coal would be a more proper

ceiling. Lignite LRMC should increase as higher stripping ratios are encountered in deposits to be brought on stream in the future, but at least over the next 15 years or so they are likely to remain somewhat below the quality- and transport-adjusted cost of imported hard coal for central locations.

11. Yugoslavia

146. Coal prices in Yugoslavia are determined in part by market forces. Pricing policy does not conform to a "hands-off" version (see para. 23), however, since consumers and producers operate within indicative Government guidelines. Although not mandatory, these guidelines are supposed to outline the magnitude and, where necessary, direction of price changes. Nevertheless, guidelines sometimes take a firmer grip, as happened in 1982 when a temporary price freeze came into effect.

147. Also, when in a region one or two large coal or lignite suppliers predominate, groups of small consumers organize themselves with official support in the so called communities of interest, to negotiate on an equal or similar footing with producers. In addition, the relationship between producers and consumers is peculiar to the Yugoslav system, so that consumers (particuliarly large enterprises) sometimes help finance part of mine expansions. Therefore, prices alone do not reflect fully the cost to consumers (nor the remuneration to producers) of the coal supplied.

148. As seen in Table 18, hard coal prices remained fairly stable at between US$45 and 50 per tonne between 1974 and 1980, after which they increased rapidly in real terms. Brown coal and lignite prices moved in parallel. As a consequence of a real term decline in fuel oil prices between 1973 and 1978, actual consumption of hard and brown coal, fell in absolute terms between 1975 and 1980. In 1980 coal met 27% of total primary energy, as compared to 41% for oil (three quarters of which is imported).

Table 18: YUGOSLAVIA - Average Minehead Steam Coal Prices a/
(per tonne)

	Current Dinars	Constant 1982 Dinars b/	Current US$	Constant 1982 US$ c/	Constant 1982 US$ per million Btu
1973	291	1,862	18.0	37.6	1.6
1974	490	2,454	29.5	49.1	2.2
1975	545	2,315	31.3	45.9	2.0
1976	614	2,336	33.8	48.7	2.1
1977	706	2,345	38.6	51.3	2.3
1978	745	2,179	40.0	45.1	2.0
1979	847	2,043	44.6	45.0	2.0
1980	1,192	2,214	47.9	44.6	2.0
1981	1,887	2,509	53.2	52.0	2.3
1982	2,602	2,602	50.7	50.7	2.2
Average Yearly Increase		4.9%		5.2%	

a/ Rough powder hard coal for industrial use (10,350 Btu/lb).
b/ Using CPI Index.
c/ Using International MUV Index.

Sources: World Bank Report No. 4797 YU

149. If the efficiency pricing principles discussed in Section II-B were to be applied, this would suggest that, given that at the margin coal is imported, its domestic prices should reflect import parity prices. Where the product is not directly or indirectly tradeable or its LRMC falls between import and export parity (the case of Yugoslavia for brown coal and lignite), it should be priced according to LRMC, plus a depletion rent where applicable.

150. In the case of Yugoslavia, reserves of hard coal are very limited (35 million tonnes are technically and economically recoverable according to the 1978 World Energy Conference), and hard coal production is only about 0.4 mtpy as compared to 3.5 mtpy of imports.[25/] On the other hand, brown coal and lignite reserves are abundant (8,400 million tonnes are technically and economically recoverable according to the same source). Output of lignite in 1982 was about 44 million tonnes.

151. The conditions for efficiency pricing according to import parity laid out above thus apply for hard coal, while in the case of lignite and brown coal pricing in line with LRMC appears to be a more proper policy; given large lignite and brown coal reserves, depletion rent has no practical significance. It can be argued that brown coal and lignite, although not directly tradeable, can substitute for imported hard coal and should thus be considered as indirectly tradeable and priced on the basis

25/ The bulk of imports is coking coal.

of adjusted hard coal import prices. However, since lignite LRMC for several regions are believed to fall below import parity for the foreseeable future, once the stage of lignite for hard coal substitution wherever economically feasible is completed in those regions, the opportunity cost of lignite will fall to LRMC. In the intervening time, the opportunity cost will be the adjusted cost of imported coal, so that lignite pricing between LRMC and import parity could be justified for some time to accelerate the process of substitution by giving strong encouragement to supply expansion while preserving lignite's cost competitiveness. This efficient price path, implying a short-run price increase and a later relative fall, in fact mirrors what would tend to happen in a purely competitive environment. It should be stressed that since there is to some extent a free interplay of market forces in Yugoslavia, it is demand and supply which will eventually dictate how prices of hard coal, brown coal and lignite move over time. Nevertheless, the general pricing principles described above could be embodied in the Government pricing guidelines since they would provide signals to coal companies and consumers which will induce them to make economically efficient investment and production and fuel choice decisions.

INTERRELATIONSHIP BETWEEN PRICES OF COAL AND THAT OF OTHER FUELS - THE CASE OF THAILAND

Thailand is one of the countries where issues concerning energy pricing have been investigated at greater depth. Studies were recently commissioned by the Thais on lignite pricing (from Meta Systems, Inc.) and on energy pricing (from PEIDA); these studies were concluded in 1983 and 1984. Prior to introducing the main conclusions derived from these studies, a brief description of Thailand's overall energy position will be useful to the reader.

Between 1960 and the mid 1970s energy consumption in Thailand grew at a fast pace (well over 10% per year on average). Although (a) that pace slowed down considerably in later years, and (b) domestic energy sources have increased their contribution to meeting demand, imported petroleum still has a share of over 70% in total commercial energy supply and of over 20% in total merchandise imports. Currently, hard coal imports are being considered as a long-term energy supply option.

Lignite and natural gas are the major indigenous energy sources; hydroelectric power and domestic oil also are expected to play a role in Thailand's energy picture. The critical pricing issue concerns the absolute and relative prices of oil products, natural gas and lignite. Since oligopolistic or monopolistic situations are present in Thailand's energy markets, the Government has sought to intervene by fixing prices of the various energy products. The PEIDA and META studies focused on fuel pricing that induce production and uses of energy resources that maximize to Thailand the net economic value from those resources.

In the case of oil products, which will remain on the margin imported goods, prices should be set in line with their CIF cost; in broad terms they currently are, but diesel is still underpriced somewhat relative to other oil products. Hard coal, when imported, would also have to be priced at CIF cost.

The findings of the above-mentioned studies suggest that the efficiency price of natural gas, which is supply constrained, should be set in line with fuel oil prices since the marginal use of natural gas is as a substitute for fuel oil in power generation. The natural gas price should include all the adjustments necessary to account for differences in calorific values, fuel efficiency factors, etc., between gas and fuel oil. The opportunity cost of natural gas thus calculated is currently considerably higher than LRMC, implying a significant economic rent. There are other possible uses of gas, such as in power generation to substitute for lignite or coal, but limited known reserves do not allow it to be diverted to these lower-value uses even though there would still be a net economic benefit in consuming gas there. However, if more natural gas wereavailable, than it could be used profitably to substitute for coal or lignite in the power sector, in which case its price should be in line (with all the necessary adjustments) with these other fuels. Also, it is conceivable that enough natural gas will be found for it to become demand constrained, which, consequently, would set its efficiency price at LRMC.

Lignite represents a very interesting situation. Currently it is demand constrained, its utilization being limited to virtually only mine-mouth power generation due to the high cost of lignite transportation relative to its calorific value. Lignite's opportunity cost is therefore equal to its resource cost. This suggests setting lignite prices at LRMC. Lignite reserves, although capable of sustaining higher production rates than at present, are however expected to be depleted within the next 40 years, so that lignite will shift from a demand-constrained to a supply-constrained situation sometime in the future. Therefore, the true resource cost should in principle consist of LRMC plus a depletion premium. However, the depletion premium lacks significance since substitution of coal for lignite (when the latter approaches depletion) will not result, on the basis of available projections of international hard coal prices, in higher economic cost to Thailand. Should long-run prices for imported coal be higher than currently projected, then a positive depletion premium would arise and lignite should be priced above LRMC. Conversely, if coal prices were lower than projected, than its LRMC would be higher than the benefits derived from its consumption and no further investments in lignite would be justified. A similar conclusion would be reached if large natural gas reserves were found so as to supply power plants at lower cost than lignite.

The above considerations illustrate the point that Thai fuel prices are not only interlinked, but also depend on variables such as international prices and gas reserves which are by nature uncertain. Thus, there is a need to review fuel prices from time to time and adjust them to the broad movements in the international oil and coal markets and to whatever changes might occur in the knowledge of gas reserves.

AN EXAMPLE OF RESOURCE RENT CALCULATIONS

Situation: Suppose country X has two coal deposits, shown in Figure A-1 as I and II, with equivalent LRMCs equal to $25/tonne. Deposit I is far from the market but relatively close to the port. The transport cost from Deposit I to the port is assumed to be $10/tonne, while the cost of transmitting power generated at I to the capital is the equivalent of $15/tonne. Suppose further that domestic demand for coal is exclusively for electricity generation, whose load center is the capital city.

Deposit II is located further from the port but closer to the capital. The transmission cost for minemouth power from II is $5/tonne equivalent. The cost of transporting Deposit II coal to the port for export would be prohibitive. At the port, the fob price for coal exports is $40/tonne, while the cif price for coal imports is $65/tonne. If power were to be generated at the port from coal imports, its transmission cost to the capital would be the equivalent of $10/tonne. What are the minemouth values of Deposit I and Deposit II coal?

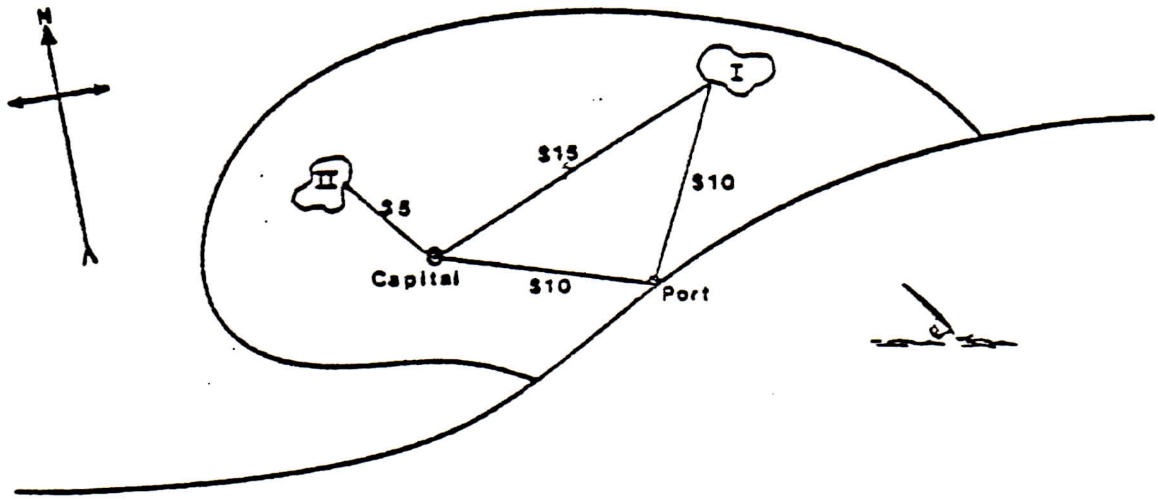

Figure A-1. Country X and its coal deposits

Case I: Assume that Deposit I is large, while Deposit II is small, relative to domestic demand. The least-cost site for the first power plant is clearly at Deposit II. Suppose that the next plant, needed 5 years laters, would have to be sited either at Deposit I or at the port due to insufficient reserves at II to provide for the continuing needs of more than one plant. At Deposit I, the net back value of minemouth coal set by the export demand is $30/tonne (40 - 10). With an LRMC of $25/tonne, this implies a depletion premium of $5/tonne. At a minemouth price of $30/tonne, the delivered cost of Deposit I power1/ at the capital would be equivalent to $45/tonne (30 + 15), which is obviously below the cost from a plant at the port based on imports (65 + 10). At the capital, then, the LRMC of coal-fired power in 5 years will be $45/tonne of coal equivalent. This defines the depletion premium for coal from Deposit II:

1/ For simplicity, the "cost of power" is used to mean the fuel cost only.

The present value of the difference between 45 and the LRMC of delivered power from II, 30. At a discount rate of 10%, the depletion value is $9.3/tonne and the minemouth price of coal from Deposit II in the current year would thus be $34/tonne (25 + 9.3). The resource rent component would increase at 10% per year until, in year 5, the total price would reach $40/tonne at the mine (and $45/tonne at the capital). The minemouth price of Deposit I coal would remain at $30/tonne.

Case II: Assume that Deposit II is large, while Deposit I is small, relative to domestic demand. In this case power needs for the indefinite future can all be met from Deposit II at a delivered cost of $30/tonne equivalent with very large reserves (but, by assumption, no economic export potential, the depletion premium would be very small, so that the minemouth price of Deposit II coal would be close to its LRMC, or $25/tonne. Deposit I coal would then be devoted exclusively to the export market, where its border value of $40 would define a depletion premium at the minemouth of $5/tonne and a minemouth price of $30/tonne for any potential small users in the vicinity.

Case III: Assume that both deposits are small relative to domestic demand, each with reserves sufficient only to supply one power plant over its operating lifetime. Again assume that the country's power demand necessitates constructing a new plant every five years. The least-cost site for the first plant will still be Deposit II. Then two scenarios are possible: either export the coal from Deposit I (as soon as possible and build the second power station at the cost based on imports, or save the Deposit I coal to be used beginning in 5 years when another power plant is needed, thereby deferring the need for a coastal plant until year 11.

To define the more efficient option, consider the resource rent accruing to Deposit I under the second scenario. From year 11 onwards, the marginal cost of power at the capital is $75/tonne equivalent (65 + 10). Netting this back to the minemouth at Deposit I by subtracting the transmission cost yield $60/tonne (75 - 15); subtracting the production cost of $25/tonne gives a depletion value in year 11 of $35/tonne. The present value of this in year 1 is $13.5/tonne, yielding a minemouth value in that year of $38.5/tonne. Since this is above the export value of the coal (i.e., $30/tonne at the minemouth), the highest value use of Deposit I coal is to leave it in the ground until year 6 when it can be used in place of imported coal. Its minemouth price will grow from $38.5/tonne in the year 1 to $46.7/tonne in year 6 (25 plus its depletion premium in that year of 21.7) to $60/tonne from year 11 onwards.

The minemouth price of Deposit II coal will follow a similar path, but it will be derived from the value of its eventual substitute, Deposit I coal. In year 6, when marginal substitution begins, the cost at the capital of electricity from Deposit I will be $61.7/tonne equivalent (46.7 from above plus the transmission cost of 15). This is netted back to the mine at Deposit II by subtracting the transmission cost of $5/tonne.

The depletion premium for Deposit II coal in year 6 is thus $31.7/tonne (61.7 - 5 - 25). At a 10% discount rate it becomes $19.7 in year 1, yielding a minemouth price of $44.7/tonne (19.7 + 25). As noted above, this grows to $56.7/tonne in the year 6. At this point, however, there will be a "kink" in the price path of Deposit II coal, similar to that shown in Figure 5, because its marginal substitute after year 6 becomes imported coal. (This kink would not occur if coal-using investments were not long-lived; in that case the use of Deposit I coal would not commence until the cheaper Deposit II coal was completely exhausted.) From year 11 onwards its minemouth value is $70/tonne (65 + 10 - 5), implying a depletion premium of $45/tonne (70 - 25). The depletion values for years 7 through 10 will be the relevant present values of this figure.

SOME PROBLEMS IN DEALING WITH LONG RUN MARGINAL COSTS (LRMC) IN PRACTICE

1. The problems dealing with LRMC computations are not limited to the selection of the calculation method. A separate Bank publication (Staff Working Paper No. 259) deals with a number of methodological questions regarding the various approaches to calculate LRMC, with the most popular in the coal sector and project work at the World Bank being the average incremental cost (AIC) method. This is mainly because the AIC approach provides a convenient way of ironing out the "lumpiness" of investments; in coal, large discrete investment projects predominate. This annex briefly describes the AIC method itself as well as some of the problems normally encountered with AIC applications.

2. The AIC method estimates LRMC by discounting (at the social rate of interest) all incremental costs (capital and operating) that will be incurred in the future to provide the estimated additional amounts of coal produced over a specified period, and dividing that by the discounted value of incremental output over that period, i.e.:

$$AIC = \frac{\text{Present Value of Capital plus Operating Costs}}{\text{Present Value of Production Stream}}$$

or

$$AIC_o = \frac{\sum_{t=1}^{T} [I_t + (R_t - R_o)]/(1 + i)^t}{\sum_{t=1}^{T} (Q_t - Q_o)/(1 + i)^t}$$

I_t - capital costs in year t
Q_t - 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 plus production life (t=o is the base year)

3. The AIC approach is also useful for comparing investment proposals characterized by widely different conditions, such as life of mines, construction time and learning curve (pattern of operations build-up to reach full capacity), and reinvestment rate. In these circumstances, the mere comparison of capital costs per ton of coal capacity or of operating costs can be quite misleading.

4. Although ultimately the selection of mining projects depends not only on mining costs but also on transport cost to consumers, for LRMC calculations one normally concentrates attention only on cost of production at the mine mouth (i.e., without transport cost to consumers). Otherwise the exercise becomes overly complex. Still, the first problem arises in deciding what the specified period should be to capture all costs and a sufficiently long production stream to "amortize" the initial investment under any particular project, usually not less than 25 years.[1] The second problem arises in defining a coal investment

1/ Mines have frequently longer lifes, but because of discounting the outer years do not matter much.

program that minimizes mining and transport costs over such a period (a least-cost program) in order to calculate the corresponding AIC. However, a country's coal investment program over long periods cannot be identified easily in practice. A shortcut approach is (a) to calculate the AIC for individual projects (an example of the type of calculation involved for one project is given in the table below) known or expected to be executed in the near future, say the next five years, and (b) reach a judgement on the pattern of the evolving least-cost investment program over the long term.

5. The above judgement should be based on whether the immediate projects can be replicated in the future (pointing to rather stable LRMC or a "flat" supply curve) or whether significantly different mines will need to be developed as the more attractive resources are depleted. In this connection, it is useful to separate possible cost increases stemming from secular trends not particular to any choice of location (such as real wage increases, introduction of technological advances) from possible increases due to the need to move to more difficult geological and mining conditions (such as exploitation of deeper or thinner coal seams).

AIC Calculation for Model Mine

Year	Capital Cost Stream (in constant $)	Operating Cost Stream (in constant $)	Production Stream (in tons)
1	10	-	-
2	20	-	-
3	30	-	-
4	30	-	-
5	30	4	0.1
6	20	6	0.2
7	2	14	0.6
8	2	18	0.8
9	2	18	1.0
10-40	6	18	1.0
Net Present Value	138.0	111.5	5.8

Assumptions:
- initial investment $140/ton
- operating costs at full capacity $18/ton
- construction time 6 years
- production buildup years 5 to 9

Therefore, the AIC is

$$AIC = \frac{\$138.0 + \$111.6}{5.8 \text{ tons}} = \$43/\text{ton}$$

6. Sometimes a simplified approach is possible. In case where reserves are so abundant that allow extensive replicability of existing mines (such as in Northern China, the Transvaal in South Africa, Eastern Queensland and South Wales in Australia or Western US), a notional least-cost coal development program covering say a twenty year period can be constructed from a rather small sample of model mines, probably quite similar to existing efficient mines. The main concern here is how to deal with a trend of real wage increases and the possible compensating technological developments leading to higher productivity. In Bank work or in work carried out by consultants for the Bank, such an approach has been used in practice for the regions mentioned above. The findings have been that in most of these regions LRMC is likely to remain quite stable for an incremental capacity of several hundred million tonnes.

7. In other countries a different approach has been used because existing mines, or those expected to be constructed in the immediate future, are not representative of a least-cost development program over the long term. In some countries the coal basins are smaller or the coal seams less flat, so that future mines will not resemble the present ones. The challenge here for LRMC calculations is naturally greater. Indeed, it might be impossible to pass judgement on LRMC beyond a modest tonnage or for more than a period of say five or ten years unless there is a large portfolio of project proposals. When coal plays an important role in a country's energy picture, normally significant prefeasibility work is carried out on prospective mines. This can lead to a large portfolio of investment possibilities such as in India or Turkey. Here preliminary AIC for individual projects can be calculated and projects can be ranked according to their AIC. In line with this ranking, one can approximate a LRMC curve on the basis of a sequence of projects likely to be executed over time.[2/] However, there might be a significant cost overestimation bias under this approach; under conditions of high variety of projects and active exploration and feasibility work, there is little certainty that new lower cost projects will not be identified in the future.

2/ Actual selection of projects will of course depend on several factors besides their individual AIC.

ENERGY DEPARTMENT PAPER SERIES

EGY PAPER No. 1

Energy Pricing in Developing Countries: A Review of the Literature by DeAnne Julius (World Bank) and Meta Systems (Consultants). September 1981. 121 pages, includes classified bibliography.

Reviews literature on the theory of exhaustible resources and on sectoral, national and international models for energy demand. Emphasis on project selection criteria and on pricing policy as a tool of energy demand management.

EGY PAPER No. 2

Proceedings of the South-East Asian Workshop on Energy Policy and Management edited by Michael Radnor and Atul Wad (Northwestern University). September 1981. 252 pages.

Contains the edited version of the lectures and discussions presented at the South-East Asian Workshop on Energy Policy and Management held in Daedeok, South Korea, October 27-November 1, 1980.

Topics that are addressed include: the overall problem of energy policy and its relationship to economic development; the management of energy demand and related data; the role and value of models in energy planning, and the use of energy balances. Transport and rural sectors are also discussed in terms of their relationship to energy planning.

EGY PAPER No. 3

Energy Pricing in Developing Countries: Lessons from the Egypt Study by DeAnne Julius (World Bank). December 1981. 14 pages.

Study on the effects of energy price change in a developing country. Provides insight into the mechanisms through which energy prices affect other prices in the economy and, therefore, the incomes of rich and poor consumers, profitability of key industries, the balance of payments, and the government budget.

EGY PAPER No. 4

Alternative Fuels for Use in Internal Combustion Engines by G.D.C., Inc. (Consultant). November 1981. 179 pages, includes appendices.

Presents several alternative fuels used as replacement for conventional (gasoline and diesel) fuels in internal combustion engines. These alternatives, including LPG, natural gas, alcohol and producer gas, are derivable from natural resources that exist in so many developing countries. Also provides up-to-date information on the newest alternative fuel option currently available and those that are being developed and tested.

EGY PAPER No. 5 — Bangladesh: Rural and Renewable Energy Issues and Prospects by Fernando R. Manibog (World Bank). April 1982. 64 pages, includes bibliography.

Analyzes subsector issues and recommends courses of action for energy project possibilities; identifies renewable energy projects which could create a positive impact in the short to medium term.

EGY PAPER No. 6 — Energy Efficiency: Optimization of Electric Power Distribution System Losses by Mohan Munasinghe (World Bank) and Walter Scott (Consultant). July 1982. 145 pages, includes appendices.

Discusses the reasons for high existing levels of power distribution losses in developing countries. Identifies areas within a power system where loss optimization would be most effective. Shows that reducing losses is often more cost effective than building more generation capacity.

EGY PAPER No. 7 — Guidelines for the Presentation of Energy Data in Bank Report by Masood Ahmed (World Bank). October 1982. 13 pages, includes 4 annexes.

The growing importance of energy issues in national economic management has led to increased coverage of the energy sector in many types of reports. However, there is still no clear, consistent and standardized format for presenting energy sector information. This paper reviews the problem and proposes guidelines for policymakers and operational staff who deal with energy issues. The paper is divided into three parts: part one sets out the basic framework for presenting aggregated energy data -- "the national energy balance"; part two deals with the use of appropriate units and conversion factors to construct such a balance from raw demand and supply data for the various fuels; and part three briefly discusses special problems posed by: (i) differences in end use efficiency of various fuels; (ii) the inclusion of wood and other noncommerical energy sources; and (iii) the conversion of primary electricity into its fossil fuel equivalent.

EGY PAPER No. 8 — External Financing for Energy in the Developing Countries by Althea Duersten (World Bank). June 1983. 66 pages, includes appendices.

Provides an overview of energy financing in the developing countries. Identifies energy investment requirements and past financing patterns. Discusses the historical roles of multilateral and bilateral assistance programs in helping to mobilize financing, particularly for low income oil importers and in providing economic and sector advice. Examines the role of official export credit, and discusses lending by private financial institutions which has been the predominant source of financing for energy projects in the middle and higher income developing countries.

EGY PAPER No. 9

Guideline for Diesel Generating Plant Specification and Bid Evaluation by C.I. Power Services, Inc. (Consultant, Canada). December 1982. 210 pages, includes appendices.

Explains the characteristics and comparative advantages and disadvantages of large low speed two-stroke diesel engines intended for electric generating plant service, and develops a bid evaluation procedure to permit comparing of bids for both types.

EGY PAPER No. 10

Marginal Cost of Natural Gas in Developing Countries: Concepts and Application by Afsaneh Mashayekhi (World Bank). July 1982. 21 pages, includes appendices.

Defines the concept of marginal cost and average incremental cost. Uses the detailed supply, demand and investment data to apply this concept to estimate the average incremental cost of natural gas supply to major markets in ten developing countries. Demonstrates that the cost of natural gas delivery to the city-gate in many developing countries is far below the cost of competing fuels.

EGY PAPER No. 11

Power System Load Management Techniques by Resource Dynamics Corp. (Consultant, U.S.A.). November 1983. 132 pages.

In recent years, techniques referred to as load management have begun to play an important role in shaping the patterns of electricity consumption in industrialized countries. Along with pricing, a variety of hardware is used to control loads directly and save on energy and peak capacity. This study reviews the state-of-the-art of these so-called "hard" techniques in light of recent technological advances, provides data on cost and manufacturers of this equipment, and identifies controllable loads in developing countries.

EGY PAPER No. 12

LNG Export Opportunities for Developing Countries and the Economic Value of Natural Gas in LNG Exports by Afsaneh Mashayekhi (World Bank). November 1983. 36 pages, includes appendices.

This paper reviews the LNG export opportunities for developing countries and clarifies some of the issues related to economic costs and benefits of LNG projects from the point of view of an exporting country. It identifies the major technical parameters that affect costs and analyzes factors affecting the economic size of projects and the effect of scaling them down. Its principal objective is to estimate, given explicit assumptions, the netback values for gas at various stages in the LNG delivery system. It examines three basic scenarios of small and medium scale projects as well as a multi-destination project with several small markets. It also tests the sensitivity of netbacks to the level of infrastructure, discount rates and the price of gas delivered at the importing country.

EGY PAPER No. 13 — Identifying the Basic Conditions for Economic Generation of Public Electricity from Surplus Bagasse in Sugar Mills by Syner-Tech Inc. (Consultant, U.S.A.). October 1983. 167 pages, includes appendices.

The study identifies several ways, all using presently available technology, to greatly increase the overall energy efficiency of existing mills, produce surplus bagasse and generate electricity for sale to the grid. These include installing pre-evaporators to conserve steam, drying wet bagasse with flue gasses to improve combustion efficiency, installing high-pressure boilers to increase steam generation efficiency and pelletizing or compressing bagasse to enable it to be stored and used beyond the harvest season.

EGY PAPER No. 14 — A Methodology for Regional Assessment of Small Scale Hydropower by Tudor Engineering Company (Consultant, U.S.A.). December 1983. 105 pages.

This paper presents a methodology for regional assessment of small hydropower development potential involving sampling procedures, study execution, energy planning, regional hydrology development, technical site evaluation, cost and economic analysis, environmental and social considerations. Its use should result in reasonably accurate estimates in a short period of time of the viable small-scale hydroelectric projects in a particular region or country. A development program based on such an assessment would be of sufficient reliability to support requests for financing assistance.

EGY PAPER No. 15 — Central America Power Interconnection: A Case Study in Integrated Planning English Summary by Fernando Lecaros (Consultant). April 1984. 55 pages.

This paper is a summary of the study, titled "Regional Electrical Interconnection Study of the Central American Isthmus", performed by the Regional Office in Mexico of the United Nations' Economic Commission for Latin America (ECLA) between 1975 and 1979. Its goal was to provide a firm economic and technical foundation to decisions about the interconnection investments in the region. The purpose of this English Summary is to disseminate the methodology retained by ECLA and to show an example of integrated system planning using models such as WASP developed by the International Atomic Energy Agency. The figures reproduced in this report are limited to the extent necessary for these illustrative purposes.

EGY PAPER No. 16 — An Economic Justification for Rural Afforestation: The Case of Ethiopia by Ken Newcombe, (World Bank). June 1984. 23 pages, includes appendices.

It has proven difficult to quantify the economic benefits of large-scale rural afforestation and to establish the priority for public investment in traditional rural energy supply vis-a-vis investment in the supply for modern fuels (electricity, petroleum) to the urban industrial market. This paper outlines, in simple terms, the biological links between deforestation and agricultural production at the subsistence level, and quantifies the economic benefits of increased food production obtained by replacing animal dung as a fuel with firewood from rural forestry programs.

EGY PAPER No. 17 — The Future Role of Hydroelectric Power in Developing Countries by Edwin Moore (World Bank), George Smith (Consultant, Canada). June 1984. 59 pages, includes annexes.

The study examines the role of hydroelectricity in the power programs of 100 developing countries in the period 1982-1995. The report indicates that hydro will continue to play a significant role, accounting for 43% of electricity production in 1995. Preparation and engineering expenditures of about $10 billion will be needed in 1982-1990 for the projects required to support this growth. The study concludes that an intensified hydro program would add only 3% to the capacity otherwise planned because the main constraints to hydro development are economic and lack of poor markets rather than lack of knowledge about resources and prospective projects. Nonetheless, the study identifies specific actions that can be taken in many countries to accelerate hydro development.

EGY PAPER No. 18 — Guidelines for Marginal Cost Analysis of Power Systems by Yves Albouy (World Bank). June 1984, 31 pages, includes annexes.

These guidelines provide hands-on but state-of-art instructions for conducting a sound and quick analysis that yields the marginal cost structure needed for applications in the power sector and for the review of related studies. These include not only pricing but also the less known marginal analysis of system planning decisions. The paper does not give the detailed theoretical background but draws on the reference literature. It illustrates the basic principles and calculation methods with the help of many examples going from the simplest to the more complicated system conditions.

EGY PAPER No. 19 — The Value of Natural Gas in Power Generation by Yves Albouy and Afsaneh Mashayekhi (World Bank). November 1984. 28 pages.

This paper is one of a series to examine the "netback value" of natural gas in major domestic and export uses. The netback can be compared to the cost of gas to permit a rough estimate of the net economic benefit to gas use in various sectors.

With the help of case studies and simple calculations, the netback value to power generation is found to be fairly high on average even though it diminishes as the use of gas spreads from peak to base load. The paper also highlights the important role of power in the natural gas market and the specific analytical framework in which an assessment of this role can be undertaken for preliminary gas utilization studies.

EGY PAPER No. 20 — Assessment of Electric Power System Planning Models by Yves Albouy (World Bank) and Systems Europe, (Consultant, Belgium). January 1985. 107 pages, includes annexes.

This paper addresses both the models and methods for power generation and transmission planning. It provides first an overview of the methodology preferred by the Bank and of the promiment planning issues in developing countries. On this basis the study attempts to assess the applicability of forty five models now available from leading utilities and consultants. The paper also contains recommendations on the development and use of models. An extensive bibliography is given in the Annex.

EGY PAPER No. 21 — Diesel Plant Performance Study by C.I. Power Services Inc. (Consultant, Canada). February 1985. 83 pages.

The study was prepared under an EGY-sponsored research project as a guideline for use by Bank staff and consultants. This report summarizes the results of an investigation of the performance and cost of operation of four stroke medium speed engines and two stroke low speed engines used as prime movers for electricity generation in both developing and developed countries. Operating data for units of 4,000 kW and larger was collected from 28 countries and is analyzed here. Data from some 3000 - 4000 kW units was also incorporated.

EGY PAPER No. 22

Eonomic Value of Gas in Residential and Commerical Markets
by Afsaneh Mashayekhi (World Bank), Sofregaz (Consultant).
March 1985. 21 pages.

This paper sums up our current knowledge on the subject of the economics of gas use in residential and commerical markets. It clarifies some of the issues related to the demand by the residential and commerical sector for gas, design of gas distribution networks and the economic costs and benefits of gas distribution to these sectors. The netback and NPV figures are estimated for 16 model networks with different demand and density patterns and types of city. The conclusion is that many developing countries with low cost gas reserves could benefit from developing and expanding their gas distribution networks to residential and commercial markets and displacing high costs fuels such as LPG and kerosene.