Appendixes

Energy sector loan and technical assistance, 1995–1999

Table A1.1: Energy sector loans classified by policy recommendations, 1995–1999

Reference[a]	Main objectives	Amount ($ million)	Share of energy sector loans (%)
87 (i)	Power sector restructuring	834.4	17.3
87 (ii) a	Power generation	891.0	18.4
87 (ii) b	Power transmission	1,332.7	27.6
87 (ii) c	Rehabilitation and strengthening of power distribution networks	290.0	6.0
87 (ii) d	Rehabilitation of district heating networks	50.0	1.0
87 (vii)	Environmental protection	265.5	5.5
88 (iii)	Efficiency improvements and environmental management in the oil and gas subsectors	178.0	3.7
88 (iv)	Natural gas development	498.0	10.3
88 (v)	Petroleum refinery rehabilitation	24.0	0.5
89 (i)	Renewable energy development	100.0	2.1
89 (ii)	Rural electrification	367.0	7.6
Total		**4,830.6**	**100.0**

[a] The references in the first column of the table indicate paragraph numbers in the: Conclusions and Recommendations in the *Bank Policy for the Energy Sector*, 6 October 1995, of ADB.

Table A1.2: Energy sector technical assistance classified by policy recommendations, 1995–1999

Reference[a]	Main objectives	Amount ($ million)	Share of energy sector TAs (%)
87 (i)	Power sector restructuring	16.9	22.8
87 (ii) a,b	Power generation and transmission	6.5	8.8
87 (ii) c,d	Rehabilitation of power distribution and district heating networks	7.3	9.9
87 (iii)	Demand-side management	3.0	4.0
87 (iv)	System planning with integrated resource planning in the power subsector	1.3	1.8
87 (v)	Private power, build-operate-transfer model	4.0	5.4
87 (vii)	Environmental mitigation	5.8	7.8
87 (viii)	Regional trade and cooperation	3.8	5.1
87 (ix)	Tariffs and subsidies	4.9	6.6
88 (i)	Private sector participation in the oil and gas subsectors	5.1	6.9
88 (iii)	Efficiency improvements and environmental management in the oil and gas subsectors	8.0	10.8
88 (iv)	Natural gas development	2.7	3.6
89 (i)	Renewable energy development	1.5	2.0
89 (ii)	Rural electrification	3.4	4.5
Total		**74.1**	**100.0**

[a] The references in the first column of the table indicate paragraph numbers in the: Conclusions and recommendations in the *Bank Policy for the Energy Sector*, 6 October 1995, of ADB.

Energy and poverty reduction

1. There are multiple links between energy, poverty, and the environment. The production and use of energy have environmental consequences to which the poor are especially vulnerable. People living in poverty are often disproportionately the victims of the environmental effects related to energy, even while they are usually perceived as being the cause of worsening environmental problems, because they (i) use inefficient and relatively more polluting energy sources and systems than those who are better off and (ii) are often forced to engage in hazardous or ecologically disruptive activities to gain access to energy services. Most importantly, however, they lack the political power to help foster institutional changes that could address their own poverty or effectively combat the environmental harm caused by the mainstream energy economy, for instance, power producers. While low energy consumption is not a cause of poverty, the lack of available energy services correlates closely with many poverty indicators.

2. Poor households and communities typically rely on diverse sources of energy, using one fuel for heating, another for cooking and lighting, and another for agricultural or other productive purposes. Often the real unit costs of these alternative energy sources are high relative to those of electricity or gas delivered through a network to wealthier households. Moreover, these energy sources have high nonmonetary costs. When women or children spend many hours collecting firewood or biomass fuels for heating or cooking, for example, they have less time for education or for developing other productive activities. Besides, the use of traditional energy sources can have serious health and environmental consequences.

3. Energy consumption and income are positively related. While energy spending rises with income, it generally does so less than proportionately. Consumption levels off as income increases, with the poor spending 10–20 percent of their income on energy, and the rich about 2 percent. Energy pricing also has environmental implications, although adjusting prices to reflect environmental externalities more accurately may have adverse effects on the poor.

4. Addressing the problems of poverty requires addressing its many dimensions, for example, providing adequate educational opportunities, health care, and accessible and functional sanitation facilities. Addressing these issues involves increasing the level of energy services. Policies and

programs that directly create opportunities for people living in poverty, to improve the level and quality of their energy services (by making more efficient use of commercial and noncommercial energy and by shifting to higher quality energy carriers), will allow them to enjoy both short-term and self-reinforcing long-term improvements in their standard of living and environmental quality. The substitution of modern energy carriers and more efficient energy conversion devices would confer sizeable gains in the purchasing power of poor households. Improvements in energy efficiency have considerable potential to facilitate development and to reduce poverty in all of its major dimensions. Conventional ideas about energy and development promote simply increasing the supply of energy rather than a more sustainable approach focused on the level of energy services. Energy services include both the types of energy sources and the devices to convert the energy into useful purposes.

5. An underlying objective of many energy sector projects is to give low-income households and communities in rural and periurban areas better access to modern energy to enable them to shift from biomass fuels to kerosene or gas for cooking, to put electric lighting in a school or power a refrigerator in a community health clinic, and to access electricity for lighting or to power equipment for household businesses. Interventions of these kinds are expected to have important and direct effects on the welfare of the poor people, as shown in the table on the following page. Such interventions may enable households to use more energy services, either because access is available for the first time or because it is at a lower cost. Greater use of energy services may deliver other benefits, particularly better health and education and, as a result, improved access to and productivity in the labor market. Better service is also likely to reduce both the monetary and the nonmonetary costs of obtaining supply.

6. Small improvements in the level of commercial energy services available to the poorest of the poor could dramatically improve their quality of life. Cross-country comparisons indicate a positive correlation between access to energy and electricity services and educational attainment and literacy among both the rural and urban poor. In fact, one of the ways in which energy strategies could meet sustainable development goals is by introducing specific technologies that would increase energy services for people living in poverty (for example, efficient lighting technologies, water pumping technologies, efficient cookstoves, modern energy forms for cooking). Such strategies could also promote job creation in rural areas and

Potential effects of improved energy services in reducing poverty

Direct effect on well-being	Direct effect on health	Direct effect on education
Improved access to lighting, heat and refrigeration	Improved indoor air quality through cleaner fuel	Improved access to lighting, allowing more time to study
Savings in time and effort (due to reduced need to gather biomass and other fuels)	Reduced fire hazard Improved quality of health services (through better lighting, equipment, and refrigeration)	Savings in time and effort, releasing time and energy to channel toward education
Improved access to information (through radio, television, and telecommunications)	Easier establishment of health centers Better education	

Source: The World Bank and Energy Sector Management Assistance Program. April 2000, *Energy Services for the World's Poor.*

thereby help those currently living in poverty acquire the capability to free themselves from poverty. Moreover, the emphasis given to policies that promote the wide availability of modern energy forms and inherently clean energy technologies would help improve the nutritional status and reduce their risks of ill health and resource depletion for people living in poverty by substituting domestic fuels like firewood and biomass.

7. Developing countries have the most to gain from a future of sustainable energy. People living in poverty are the most vulnerable to the negative environmental effects of current energy development and would benefit the most in terms of social and economic development from a sustainable energy future. The provision of energy services is necessary but not sufficient to reach sustainable development goals. Energy activities can affect

Direct effect on economic opportunities for the poor	Trickle-down effect of increased productivity	Fiscal effect (coupled with pro-poor policies)
Easier establishment and greater productivity of businesses that employ the poor	Easier establishment and greater productivity of business in general (including through positive impact on the environment)	Smaller fiscal burden and higher fiscal returns from more efficient services
Creation of employment in infrastructure service delivery		More benefits to the poor if government spending is effectively channeled toward welfare-enhancing services
Improved health and education and savings in time and effort, increasing individual productivity		Higher fiscal returns associated with higher growth

the goals of poverty and environment in profound ways, and a shift in the existing energy supply paradigm must occur such that it supports sustainable development and sustainable energy. Policies to promote implementation of sustainable energy strategies must be sufficiently resourceful and yet adaptable to local situations to be able to address the numerous challenges. Moreover, policies must take advantage of demand-side as well as supply-side strategies that improve the efficiency of energy use, make more effective use and transformation of conventional fuels, and use renewable sources of energy more widely. While some of these strategies can be used directly to increase the level of energy services available to those living in poverty, others can be used indirectly for satisfying their basic needs, often through increased job creation.

8. In essence, meeting the sustainable energy needs of the poor means finding technological and institutional innovations that lower the costs of obtaining and using energy services, and adapting these services to the requirements of poor households and communities. Energy services are provided most cheaply and conveniently, and with the least local pollution, when they are derived from electricity or gas delivered through networks or, in remote locations, from modern decentralized systems. However, substantial barriers may prevent low-income households and communities from gaining access to energy services. These barriers include (i) limited ability to fund the high costs of connecting to the networks; (ii) increased effective costs of access to energy due to additional cost of purchasing appliances; (iii) low densities of energy demand, especially in rural areas; (iv) costly alternatives; (v) lumpy investments in nongrid technology; (vi) inappropriate commercial mechanisms to interface with customers in poor households in informal settlements or small and dispersed rural communities; (vii) inadequate access to credit for financing service connections; and (viii) inability to pay market-oriented tariffs. To improve the services for the poor, the critical question is what kinds of policies and projects would be most successful and cost effective in knocking down these barriers. New generation and distribution technologies and easily replicable models for community mobilization are essential to improving services for the poor. The main challenge for policymakers is to identify the kinds of interventions most likely to yield large and lasting benefits for the poor.

9. The way in which the energy sector is regulated and prices are set has important implications for access: both direct, affecting affordability; and indirect, affecting the possibility of access. Once households gain access to energy, consumption depends on affordability. The pricing of fuels is crucial in determining the amount consumed and the share of income this absorbs. Because many countries have subsidized some fuels in the past, reforms commonly include removing or restructuring these subsidies and thus affect the prices charged.

10. The key tools at the disposal of governments as they try to open opportunities for pro-poor innovations in the energy sector are institutional ones. They include choices about market structure and ownership, regulation, and pricing. In efforts to help the poor enter the market for better energy services, tools are likely to include not only a targeted lifeline subsidy policy but also liberalization of financial markets to ease access to credit that could

finance investments in pilot or demonstration projects that increase market penetration for promising new technologies. To make energy affordable for the poor, governments should consider absorbing part or all of the sunk costs of energy infrastructure needed to serve the poor, designing cost-reflective price signals for baseload power at low cost for essential services, favoring decentralized renewable energy systems in rural areas, and building the capacity of local energy enterprises.

Competition in the natural gas subsector

A. Key issues

1. Experience all over the world during the late 1980s and 1990s has shown that more natural gas reserves remain to be discovered than was earlier believed. The abundance of this resource and the availability of advanced technology for its use such as combined cycle power plants, which produce the minimum amount of greenhouse gases per unit of electricity generated, have made extensive fuel switching from the more polluting fossil fuels to natural gas environmentally desirable and economically attractive. Further, in the developing member countries (DMCs) of the Asian Development Bank with abundant natural gas resources, there is a need to reorient policies to promote increased domestic utilization of this resource. Indonesia, for example, is the world's largest exporter of liquefied natural gas, but uses less than 20 percent of its natural gas production for domestic consumption. Investment needs for the oil and gas subsectors for the period 2000–2005 for seven DMCs with significant natural gas resources have been estimated at about $100 billion.[1] As in the case of the power subsector, there is a need to undertake sector reform to attract foreign and domestic private sector investment and to ensure increased domestic utilization of the indigenous resource.

2. By the early 1980s it was realized that there were limitations of the approach involving the use of (i) vertically integrated state-owned enterprises as monopolies to handle all aspects of the oil and natural gas business, and (ii) point-of-sale price controls. The latter induced underinvestment in resource development and in gas infrastructure, which in turn led to a significant reduction in exploration for additional resources. Since then the move has been in the direction of price decontrols and increasing common access to essential facilities. This shift has led to the gradual unbundling of vertically integrated state-owned enterprises to foster competition in the upstream (exploration and production), midstream (gathering, treatment, and transmission), and downstream (distribution networks and retailing operations) activities in the gas subsector.

[1] Estimate by the Center for Energy-Environment Research and Development, Asian Institute of Technology for People's Republic of China, India, Indonesia, Malaysia, Pakistan, Philippines, and Thailand.

3. The key elements of the policy to attract private investment are (i) sector unbundling to enable competition and clearly separating the roles of government as the sovereign owner of the natural resources, policy maker, regulator, and commercial operator; (ii) moving from an administered price regime to market-determined prices for natural gas as a commodity with the costs of transmission and distribution services determined by cost-of-service regulation initially, and by price-cap regulation at a later date; (iii) reviewing the terms of the production-sharing contracts (PSCs) and concession agreements evolved essentially for the exploration and production of oil, a more readily and easily tradable commodity than natural gas, and adjusting them to suit the realities of the natural gas market; and (iv) adopting a proactive role for the state in the creation of gas transmission grids and distribution networks with nondiscriminatory access to facilitate marketing of gas. Since in many DMCs the existing laws may not allow these policy approaches, it is necessary to enact new hydrocarbon laws, which enable sector restructuring, privatization, entry and exit for the private sector, competitive markets, and independent regulation.

B. Gas subsector restructuring

4. Based on a range of experience in different countries, the practical method of restructuring the subsector could be along the following lines.

(i) The government will have the responsibility for formulating policy, enacting legislation, exercising the sovereign right of ownership of mineral resources, undertaking resource surveys, identifying acreages for exploration, carrying out transparent and credible rounds of bidding, selecting the exploration and production (EP) contractor, and awarding concessions or PSCs. It will also supervise the performance of EP contractors and collect the state's share of production, royalties, and taxes. The policy-making and legislative functions are best performed by the ministry of energy or by the ministry of oil and gas, if there is such a separate ministry. The rest of the functions are best delegated to a government department, which would report to the said ministry, and be staffed by experts drawn from the erstwhile state-owned oil and gas company, or otherwise recruited from the industry and trained for this purpose.[2] This department should have one or more separate

[2] In practical terms, this may prove difficult in view of the significant differences in the salaries and benefits of civil servants and oil and gas company officials. Innovative contracting and consulting services arrangements may have to be developed.

directorate(s) for natural gas to focus on problems specific to this subsector without clubbing it with the oil subsector.

(ii) The EP contractor operating under a concession or a PSC will be responsible for the upstream activities and for marketing of the entire production, including the state's share. The erstwhile state-owned oil and gas company should be no more or no less than an EP contractor and should not receive any preferential treatment by way of reservation of more promising acreage. It could compete on an equal footing with all others in the rounds of bidding either by itself or by forming joint ventures with other partners. The state-owned oil and gas company should be divested of the responsibilities assigned to the government, and should no longer exercise them to avoid conflicts of interest and generate confidence among international and domestic investors.

(iii) Transmission of natural gas (i.e., in pipelines under pressure) should be the responsibility of one or more transmission companies based mostly on geographic considerations and potential size of the natural gas market. The operation of each transmission grid should rest with one transmission company and it could either be on the basis of contract carriage, wherein the company is obliged to provide service only to users holding firm contracts, or it could act on the basis of common carriage with nondiscriminatory access to all sellers and buyers. In the latter case, the transmission company will have the obligation to forecast demand and provide optimum transmission capacity to meet such demand. Since the company will function as a monopoly, the transmission charges would be subject to cost-of-service regulation (and price-cap regulation in later years). The company will not be allowed to purchase gas for resale. Similar common access and regulation may also apply to companies engaged in other midstream activities such as gas gathering and gas treatment, to enable adjoining small and marginal fields to make use of the common facilities.

(iv) Separate transmission pipelines from a producer to one or more large consumers with long-term transmission contracts could be allowed, on a nonexclusive basis, to be built as contract carriage transmission pipelines by entities other than the producer. Such pipelines will have an obligation to provide nondiscriminatory access to other users up to the limit of the available transmission capacity.

(v) Several distribution companies would also be organized on the basis of geographical considerations and potential markets. When there are issues of "anchor" consumers to attract investments, limited period exclusivity can be offered as an incentive. More generally, distribution companies should be large enough to enjoy economies of scale and numerous enough to ensure competition in the wholesale market. It is best to organize them as investor-owned franchises, generally on a nonexclusive basis to enable large consumers to buy gas directly from producers using dedicated bypass lines if they so choose. Based on the successful experience in Argentina, Colombia and Mexico, such franchises are awarded best to qualified strategic investors on the basis of international competitive bidding (ICB) with distribution tariff as a key selection criterion. Thereafter, they will be subject to regulation. Distribution companies and large consumers (or their brokers or aggregators) would buy gas directly from EP contractors or their brokers, or through energy merchants, on the basis of negotiated prices in a competitive market with many buyers and sellers. The price at which the distribution company will sell gas to its consumers will be a sum of the gas price it pays to the producer on the basis of negotiated contracts, the regulated transmission cost it pays to the transmission company, and the cost of its own distribution service, which is subject to regulation. It is best that distribution franchises are given for relatively short periods—such as 10–12 years—and be made subject to fresh ICB at the end of the period.

(vi) Cross-ownership among EP contractors, transmission companies, and distribution companies that restricts competition and enables price manipulation should be prohibited.

(vii) Regulation would be by a body that is independent of all other participants in the sector and is accorded an autonomous status by the government. It should not be a part of a government ministry or department. Its focus would be to promote competition in the wholesale market; regulate charges for transmission and distribution services; provide inputs for dispute resolution; enforce technical, safety, and even environmental standards and codes (the standards and codes could be separately developed by the government); and oversee the behavior of all participants in the natural gas grid and competitive markets in relation to the licensing conditions.

(viii) Further unbundling of the functions of distribution companies by giving all consumers a choice of their supplier is not recommended at this stage, as the world experience in this regard is limited to Ontario, Canada, and United Kingdom, where such unbundling was done only in 1998. It is best to wait a little longer to understand fully the technical and managerial complexities involved in such a development.

C. Roles of the public and private sectors

5. Based on a restructuring approach detailed above, the existing state-owned oil and gas companies should be split first into business units for (i) exploration and production, (ii) transmission and other midstream activities such as gas gathering and treatment, and (iii) distribution and retail sales. Activities allocated to the government must be removed from the state-owned company and relocated in the government. After doing this, the business units should be privatized to strategic investors on the basis of transparent ICB. As long as the principles of unbundling are respected and observed, there could be a case for the public sector to remain in the transmission business, if the response from the private sector for this activity turns out to be lukewarm. Further, at the infancy stage of gas market development, there could be a case for the state to play a proactive role in making the transmission investment to enable the operators of small and marginal fields to market the natural gas directly to large consumers. Unlike oil, which is easy to transport and market, natural gas is difficult to transport except by building gas pipelines or by constructing expensive facilities to liquefy the gas and transporting it in cryogenic containers. With the government taking the initiative to build the pipelines in the public sector, it would be easier to market the produced gas and this would attract a larger flow of private sector investment in exploration and production. When the main contours of a gas grid emerge, the government could move out of this business by privatizing the grid. A similar proactive approach to gas distribution networks might also be appropriate as a temporary second-best solution in DMCs that are unable to attract private investments in this segment because of country-risk considerations.

D. Approaches to natural gas pricing

6. The approach to the pricing of natural gas is largely determined by the proposed market structure. The price of natural gas as a commodity (producer price) will be on the basis of negotiated contracts between producers and large consumers and distribution companies in a competitive environment. Transmission and distribution tariffs will be regulated and the

consumer price would be the sum of gas price and transmission and distribution charges. The regulated distribution tariff to the various classes of consumers should reflect their cost of supply. The practice of making the industrial and commercial consumers subsidize the residential consumers could be counterproductive, as it may prevent fuel switching. Significant capital costs have to be incurred by industrial and commercial consumers for switching to natural gas, which would be less likely without a significant increase in fuel efficiency.[3] Further, in the absence of suitable penalties for pollution, matching the cost of mitigation measures, the environmental advantage of natural gas is not attractive enough for fuel switching. The key elements in pricing are (i) removal of subsidies from all competing fuels; (ii) avoidance of cross-subsidies within the natural gas subsector by eliminating subsidies for power generation, fertilizers, steel, etc., and for residential consumers; and (iii) if the government wants to subsidize the consumption by the poor, provision of direct cash subsidies from the budget to the target population, possibly through social security payments or income supplements. In the case of most industrial and large commercial consumers, the natural gas price could be negotiated between the supplier and the consumer. In the case of smaller consumers, a ceiling price could be prescribed on the basis of liquefied petroleum gas price.

[3] This is the case in most industries except power generation and fertilizer, where natural gas is used as fuel and feedstock, respectively.

Private sector participation in power subsector and competition

A. Experience with build-operate-transfer projects

1. Investments from the private sector in power generation since the early 1990s have predominantly taken the form of build-operate-transfer (BOT) or similar projects having power purchase agreements (PPAs) between state-owned utilities and private sector developers. Available information relating to nine developing member countries (DMCs)[1] of the Asian Development Bank alone indicate that over 117 projects with a total capacity in excess of 42,000 megawatts (MW) are being financed under this mechanism. These projects are in operation, or under construction, or have achieved, or are about to achieve financial closure. Another 24 projects with a total capacity exceeding 23,750 MW are in the development (planning-bidding-negotiation) stage in these countries. In some DMCs, such as Indonesia, Malaysia, and Philippines, the independent power producers (IPPs) already form a significant percentage of the total power-generation capacity in the country. A World Bank study estimated the total investment during 1995–1998 in greenfield power projects with private sector participation in DMCs to be of the order of $43 billion.[2]

2. Based on the experience in many DMCs, implementation of private sector BOT projects has helped overcome supply constraints. The net benefit to the economy, however, has not always been positive. In most cases, state-owned electricity utilities acted as the exclusive or single buyer on the basis of PPAs. The "buy" decisions in some DMCs were taken somewhat casually in the context of existing or anticipated supply shortages. Sometimes extraneous political considerations compelled utilities to buy capacities far in excess of demand estimates, highlighting the need for a strong governance framework. A large number of unsolicited proposals for BOT projects were finalized and the developers were selected without transparent international competitive bidding (ICB). As a result, the price for electricity agreed under take-or-pay contracts was substantially higher

[1] Bangladesh, People's Republic of China (PRC), India, Indonesia, Malaysia, Pakistan, Philippines, Sri Lanka, and Thailand. Data for the PRC exclude Dayabay, Pearl River, and Shajiao B power stations. The data for India cover only a fraction of the total number of cases.

[2] The World Bank and Energy Sector Management Assistance Program. April 2000. *Energy Services for the World's Poor.*

than the generation costs of the utility (which included explicit and implicit subsidies from the government) and sometimes even higher than the average consumer tariffs. In some DMCs, proposals were solicited from the private sector guaranteeing a specified rate of return on the invested equity. Apart from failing to provide any motivation to the project developers to minimize costs, such an approach led inevitably to endless bureaucratic interventions and controversies relating to the reasonableness of cost estimates, debt-equity ratios, and the efficiency and cost-effectiveness of implementation arrangements. These led to excessive delays in the creation of the urgently needed additional capacity. Thus the approach of buying a project (with a review of the complete project proposal), rather than focusing narrowly on the purchase of power (price of supply), proved counterproductive.

3. Rather than the BOT model itself, it is the manner in which the BOT option was pursued that resulted in (i) severe upward pressure on the end-user tariffs, which were usually inadequate to cover the full cost of supply owing to the traditional foot dragging for periodic tariff revisions by governments based on political considerations; (ii) isolation of the IPPs from the influence and discipline of the markets; (iii) creation of an enormous volume of contingent liabilities to the governments, considerably aggravating their fiscal management problems; and (iv) unhealthy price rigidities distorting markets and seriously hampering the move toward competitive markets. Contract-based regulation with limited flexibility also makes it difficult to respond to changes over time, because not all eventualities can be identified or suitably addressed at the beginning. The government, regulators, or the project owners can exercise little discretion during the tenure of the PPA (10–20 years) to align project operations to unforeseen macroeconomic or other changes.

B. Improvements in application of the BOT mechanism

4. A lesson learned is that, for achieving the best outcomes from the BOT mechanism, appropriate policy, institutional and governance frameworks, and practices are required. The experience highlighted earlier points to the need to proceed cautiously when using the BOT option with a single buyer model in DMCs where such frameworks are not yet fully in place to provide the necessary underpinnings. All the caveats mentioned in the 1995 Energy Policy[3] are still valid and the buy decisions of the utilities have to be

[3] R4-95, Revision 2: *Bank Policy for the Energy Sector*, October 1995.

taken responsibly based on credible load forecasts and least-cost power development plans. To assess the total generation capacity that can be built using the BOT option, it may be prudent to determine a risk-free supply-demand gap that reflects a realistic scenario. Project development cost and risks can be considerably reduced if site identification, land acquisition, access roads, and other facilities can be prepared well before the invitation of bids from IPPs.

5. The selection of the IPPs must be based on transparent ICB procedures. Ranking of bids should primarily be based on the offered price of electricity from the project. Take-or-pay contracts, if needed, should be given only for a part of the production capacity and energy generation capability, making the IPP share some of the demand and dispatch risks. There should be a fair and equitable sharing of other risks as well. The IPPs should take some market risk, exchange rate risk, and payment risk. Government guarantee is undesirable, but if it is absolutely necessary, should be limited only to the payments needed to service foreign debts, which would taper off as such debts are retired.[4] The government must continue to guarantee against nationalization, and place no restrictions on the repatriation of dividends or proceeds from asset sales. Also, the duration of the PPA should not be unduly long, and should be limited to the maturity of the senior debt. More than anything else, there should be a clear provision to terminate the contract or convert the IPP unit into a merchant power plant[5] on terms fair to both parties, in the event of the government reforming the power subsector to introduce competition. Unlike in the earlier PPAs, the buy-back and buy-out provisions should be more equitable and fair to both sides.[6] Also, state-owned utilities should not sign take-or-pay contracts with electricity prices higher than its carefully calculated "avoided generation costs."

6. In DMCs that are well placed to introduce competitive pool arrangements, the implementation of merchant power plants should be encouraged. Under the current practices in the region, for lenders to extend long-term loans on a non- or partial recourse basis, the PPAs tend to protect the whole project by multiple guarantees and provide for onerous buyout

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[4] This is based on the well-known principle that guarantees are needed to protect the lenders, and the equity holders shoulder greater risks and in return get higher rewards.

[5] Merchant power plants do not have government-guaranteed PPAs and function in a competitive milieu of multiple sellers and multiple buyers taking the demand risk, dispatch risk, and price risk.

[6] The use of multiple triggers could provide for greater comfort for both sides.

and buyback conditions. These conditions hinder future structural reforms in the sector and the introduction of competition for the sale of bulk electricity from private power projects. An answer to this problem could be merchant plants that do away with such PPAs.

7. DMCs with small generation capacity cannot introduce competition for the sale of bulk electricity, and the risk-free supply-demand gap that can be met through BOT projects is also limited. In such a situation, private sector participation can be increased through strategic partnership in power generation and franchising or sale of segregated companies responsible for power distribution in different regions.

C. Competition in power subsector through restructuring

8. In large power systems, the optimal solution is to unbundle power generation, transmission, and distribution by restructuring the power subsector, with several generation companies and several distribution companies selling and buying in a competitive power market. Further, consumer choice can be included to enhance competition by separating out the supply business (actual sale of electricity and associated customer services) from distribution, which will be left with the wires business (similar to a transport business; includes management of the distribution network). Most of the members of the Organisation for Economic Co-operation and Development are moving toward fully competitive electricity markets (with customer choice) according to fixed timetables. Since consumer tariffs in these countries reflected the cost of supply by vertically integrated monopolies, unbundling and competition have resulted in a significant lowering of bulk electricity prices.[7]

1. Competitive electricity markets in developed countries and DMCs

9. There are some key differences between the more developed countries and the DMCs that are worth noting while considering the policy options for establishing competitive electricity markets.

[7] The establishment of competitive electricity markets has been discussed at length in the report: TA 5753-REG: *Developing Best Practices for Promoting Private Sector Investment in Infrastructure–Power*, 2000.

(i) In the more developed countries, power tariffs under the regulatory regime tended to approximate the costs of supply; hence, competition, which tends to reduce costs, also reduced tariffs. The relative affluence of consumers in some instances has resulted in consumer choice for the more expensive "green power." In DMCs, power tariffs tend to be opaque and are often below supply costs. Consequently, competition and privatization may initially lead to price increases to reflect true supply costs.

(ii) In the more developed countries, the power market is nearly saturated both in terms of geographic and population coverage. In the DMCs, extensive areas and significant sections of the population do not have access to electricity, and markets are not suitable for the expansion of power grids to connect small and marginal consumers with a weak paying capacity.

(iii) Subsidy for consumption of energy is not a major need in the more developed countries, but DMCs often regard subsidies (and cross-subsidies) as necessary. Markets are not the best instruments for providing subsidies.

(iv) Competition increases transaction costs and legislative responsibility and renders the role of government more complex and sophisticated. Unbundling may actually increase the nonpayment problem unless effective legal mechanisms are in place. While these issues are well handled in more developed countries, DMCs may need considerable capacity building.

10. Still, the movement to markets is considered the viable solution for most of Asia for the following reasons.

(i) Government-owned, vertically integrated utilities in many DMCs have reached the limits of what can be achieved through economies of scale, and cannot continue any longer in the "business-as-usual" mode.

(ii) Governments have to recoup the past investments in the subsector and preempt future contributions to it to concentrate on urgently needed poverty reduction-related tasks and provision of other public goods.

(iii) Private investments perform most efficiently only in a competitive milieu and with freedom of entry and exit, and not necessarily in the BOT type of situation.

(iv) Several DMCs have the basic legal, financial, and political infrastructure that with some improvements could enable them to handle the issues inherent in a competitive market.

(v) Allowing markets to handle the energy needs of the normal viable segments frees the government to use its scarce resources to provide access to commercial energy to the poor and rural consumers.

2. Stages in the evolution toward competitive markets

11. The process of unbundling and restructuring the power subsector toward the goal of competitive markets and consumer choice can be considered as moving through the following five stages.[8]

a. Stage 1: Government department/utility stage

12. In this stage, the subsector is vertically integrated and operations are carried out by a government department or a statutory body fully owned by the government, which usually adopts government rules and procedures. Its capital assets are all financed by excessive government equity contributions that do not get any return, and loans with terms distinctly more favorable than what can be obtained in the financial market. Fuel is subsidized and exemptions are granted from taxes and duties, and failure to repay debts is often ignored. Investments are made to meet forecast demand with the approval of the government, but most often system reliability needs are not met. Tariffs are usually well below costs. Numerous subsidies effectively delink costs and tariffs. Ownership, regulatory, and management roles are blurred. Utilities in this stage often face a near bankrupt situation and are routinely bailed out by the government. Because of lack of management focus, consumers often suffer from power shortage and poor quality of supply.

[8] Hunt, Sally and Graham Shuttleworth. 1996. *Competition and Choice in Electricity*. New York: John Wiley and Sons.

b. Stage 2: Regulated utility stage

13. In this stage, the utility is corporatized and commercialized, and separated from day-to-day control by the government. It is registered under the company law with the government still owning 100 percent of the equity. Assets are inventoried and revalued in the light of their remaining useful lives. The debt-equity ratio is rationalized following commercial norms, and the terms of debts are realigned to match such norms and the useful life of the assets financed by them. The company is allowed to be operated autonomously under the control of its board of directors or commissioners. An independent regulatory authority is established to provide transparent, fair, professional, and timely regulation of tariffs ensuring, simultaneously, (i) that the utility is able to cover its cost of supply subject to clearly laid down efficiency norms and earn a reasonable return on its equity; and (ii) that the consumers' interests are adequately taken care of. The utility, which is still vertically integrated, has the obligation to meet the demand in its franchise area at stipulated levels of reliability. The utility under this situation is called a "regulated vertically integrated monopoly."

14. In this stage the government can impose on the utility a range of social obligations, such as fuel diversity, preferential use of locally produced coal, preferential use of renewables, environmentally benign generation, demand-side management measures, lifeline tariffs for the poor, cross-subsidies between domestic and industrial consumers and between rural and urban consumers, and rural electrification. The government can enforce these obligations by passing the necessary legislation or policy announcements to be followed by the regulator. The regulator then can recognize the costs arising from these obligations or policies and allow the utility to recover them through its tariffs. The essence of the regulated market is the absence of consumer choice, and the captive monopolized consumers can be made to pay above market prices because of the inherent information bias in a regulatory regime. If continued indiscriminately for long, subsector viability gets seriously eroded, with the consumers paying more than necessary when the utility "captures" the regulator, or more commonly, supply standards deteriorating because of weak regulation.

c. Stage 3: Single buyer model stage

15. In the single buyer model or monopsony model, power generation companies sell power to a single buyer, usually a utility with its own generation, transmission, and distribution facilities. The transaction is covered by PPA contracts with a take-or-pay clause. The selling generation

companies are called IPPs[9] and their power plants may be built on a BOT basis. Many Asian utilities have followed variations of this model for attracting private sector investment. IPPs face competition only during selection when a transparent bidding procedure is used for determining the most attractive price and nonprice terms in the PPA. If the single buyer has its own generation and it determines generation dispatch procedures, an IPP would be unwilling to take any market or demand risk, and seek a take-or-pay contract for the entire capacity in MW and energy kilowatt-hours. To introduce some element of competition and to enable IPPs to take some portion of the market or demand risk, the single buyer needs to divest all of its generation units and reach a neutral position, wherein it can dispassionately dispatch energy from all generation companies (IPPs and generation companies divested by the single buyer) on the basis of offered prices or incremental generation costs.

16. The single buyer agency can be a transmission company and distribution company combination, or simply a transmission company selling power to the distribution companies. It will buy power at different prices from the various generation companies and sell to the distribution companies at an average purchase price plus transmission cost. The transmission company (or the transmission and distribution company combination) would still be a monopoly that can carry social obligations, unrelated to generation, through regulatory mechanism. Usually this could be a good transition model before reaching the competitive stage. The single buyer can buy hydropower at a lower-than-market price to avoid windfall profits to a hydropower producer and at a higher price from a thermal power plant to avoid losses and bankruptcies, which would be the case when competitive markets are introduced. In transition economies, this stage would provide some temporary moderating influence.

17. The capacity additions under this stage are still based on demand forecasts and central plans, rather than market prices or profit expectations. Generation costs are still not determined by direct competition, which makes governance difficult and opens opportunities for corruption under the PPA regime.

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[9] The name implies that the price of bulk electricity from a BOT project is not scrutinized by the regulator. That does not matter when IPPs are not permitted to sell directly to consumers as the single buyer is subject to economic regulation, thus providing a check on power purchase cost.

d. Stage 4: Wholesale competition stage

18. In this stage there are several sellers and several buyers for electricity, i.e., competition. Several generation companies sell directly to several distribution companies. Power transmission would be on an open-access basis and there would be an independent system operator responsible for dispatching power plants, and a power pool or a spot market.[10] Forward markets would exist so that buyers and sellers could conclude contracts for long-term supplies and hedge the prices obtained in the spot market. All the players would have freedom of entry and exit and operate as private sector companies. The transmission company and distribution companies (network part) would be regulated and distribution companies may share some social obligations through the regulatory mechanism, since the consumers do not have any choice while availing of their services. The distribution companies can be obliged to buy "green power" through portfolio standards or through renewable energy funds. At this stage, competition is only at the bulk electricity level. It still requires sophisticated accounting and settlement mechanisms, and a high degree of respect for contracts and payment obligations. Further, when competition comes to this level, the problem of stranded costs[11] has to be recognized and addressed. In many countries, to increase the level of competition, large consumers located within the franchise area of distribution companies are also allowed to buy directly from generation companies, which introduces consumer choice. When this stage matures, there are questions regarding the distribution company's obligations under its franchise, and to resolve these questions the market has to evolve to the next stage.

e. Stage 5: Retail competition and consumer choice stage

19. In this stage unbundling extends to the distribution company level. Thus, the distribution company would be responsible for the distribution wires system and its operations, but the retail supply business would be run separately, either by the distribution companies with functional unbundling, or by supply companies. No one has a franchise for sale of energy

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[10] A power pool allows financial transaction among generation companies and distribution companies based on bid prices during trading intervals, while the actual power flows are governed by laws of physics and managed by the system operator.

[11] Stranded costs reflect a utility's obligation that cannot be met fully in a competitive environment. The obligations could be those imposed by the regulator or through contracts, which were acknowledged by the regulator while determining consumer tariffs. Therefore, when bulk electricity competition is introduced (deregulation), the utility would need a separate instrument for a few years to recover the stranded costs from existing consumers.

services, and consumers are permitted to buy from any producer, or agent, or supply company. The transmission companies and distribution companies allow nondiscriminatory access to their facilities for the transaction to take place. This is the final stage of a fully competitive electricity market that has evolved in some more developed countries. The role of the regulator is limited to price regulation of the wires business, and regulatory mechanisms cannot be used for any length of time to support social obligations in the absence of monopoly franchise. Special legislation may be required to enforce them, along with tax revenues or other resources to meet the costs arising from such social obligations. For example, if the government wanted to promote "green power," it would be required to buy such power as long as the prices are higher and sell it at market price; the resulting losses would then be met through such funds as renewable energy funds coming from tax revenue.

D. Privatization aspects

20. When the subsector is restructured on these lines, power generation and supply becomes fully competitive, and all generation, transmission, distribution, and supply companies could be in the private sector. Several DMCs are adopting the policy that new generation investments should come from the private sector. At least initially the transmission company could continue to be in the public sector and later could be privatized to a strategic investor taking care to ensure that there is no cross-ownership among the transmission company, generation companies, and distribution companies, which could again result in vertical bundling of services. Dedicated transmission lines connecting specific generating units to the power grid could be owned by independent private transmission companies. It is possible that some hydropower plants associated with multipurpose dams might be retained in the public sector and could compete with other private generation companies on an equal footing to sign contracts with distribution companies, or sell electricity to the power pool subject to their following the grid code. The power pool operator would be independent of all other players in the sector and would be a nonprofit-making body serving the sellers and buyers in a neutral fashion.

21. The reason for the generation and distribution companies being in private sector is both ideological and practical. The ideological aspect relates to the need for governments to divest commercial activities and concentrate on social services and provision of public goods necessary to achieve the overarching poverty reduction objective. The practical aspect relates to

the commonly observed phenomenon of competition being driven by profit maximization, management efficiencies being driven by balance sheet pressures, and standing in the financial and capital markets being based on disclosures in the audited financial statements. The responsiveness to such pressures is far more prominent in the private sector than in the public sector.[12] Publicly owned distribution systems in most DMCs invariably suffer from high levels of system losses, poor billing and collection procedures, and high levels of accounts receivable. Privately owned systems cannot survive on that basis, since system losses for them are cash losses that will result in their bankruptcy and liquidation. There are some examples of efficient public sector organizations that perform as well as private sector ones, however, they are exceptions rather than the rule. Further, the exit of failed enterprises from the industry is easier for privately owned companies than for the public sector ones. Finally, in order to enable credible independent regulation, it is best that the state is out of the businesses being regulated.

22. Creation of credible, independent, transparent, and competent regulation is the key to the success of restructuring and encouraging domestic and foreign private sector investment in the power subsector. The regulator will foster competition; enforce market rules, and grid and safety codes (possibly including even environmental standards); ensure that all players conform to the conditions of their licenses; and provide inputs to resolve sector related disputes. In case the participants face a problem in implementation of the originally established market rules, the regulator can be approached to seek a review. While the price of bulk electricity is determined by the market, the regulator determines the tariff levels for transmission and distribution wires services on the basis of cost-of-service regulation (linked to efficiency benchmarks) or price-cap regulation. Finally, the regulator has to be alert to the dangers of "rebundling" the sector through cross-ownership among the players and through acquisitions and mergers (such as generation companies acquiring distribution companies or generation companies amalgamating to secure a dominant market share) to the detriment of effective competition. Antitrust regulations must be enforced either by the regulator directly or through special bodies appointed for the purpose.

[12] Based on worldwide experience in the computer and communications industries, the private sector has scored spectacularly in respect of entrepreneurial skills and innovation, which are difficult to promote in the public sector.

E. Need for domestic debt and bond markets

23. The experience in the recent Asian crisis also highlighted the need for the prospective private investors to have access to domestic long-term finance (with longer maturity of debt). The crisis resulted in a double mismatch in the power subsector in many DMCs. The first was the supply-demand mismatch as a result of the sharp decline in power demand (as a function of declining gross domestic product growth) in the context of excessive supply capacity covered by take-or-pay contracts. The second mismatch was that the revenues of utilities were in local currency while their payment obligations were mostly in foreign currency or tied to exchange rates prevailing at the time of PPA signing. In the context of sharp devaluation of the local currency, the payment obligations of the utilities rose steeply in local currency terms, bankrupting most utilities with a large numberof take-or-pay contracts.[13] This crisis highlighted the weaknesses in the method of financing of BOT projects. High debt-equity ratios, almost total reliance on foreign currency debts, and a mismatch between the relatively short maturity of the debts and the long useful life of the financed assets led to high electricity prices (payable mostly in foreign currency) and to serious liquidity problems in the context of sharp devaluation of the local currency. In countries where debts were raised in local currency and in the domestic capital and debt markets (such as Malaysia, Thailand, and to some extent in the PRC and India) the problem was much less severe. This highlights the need for (i) promoting the development and deepening of well-regulated domestic capital and debt markets; (ii) channeling pension funds, insurance funds, and social security funds to the domestic long-term debt and bond markets; (iii) promoting infrastructure funds capable of providing long-term debts for private sector power projects; (iv) promoting the concept of stress-testing foreign investments against exchange risk and pricing foreign currency loans properly, as well as taking hedging protections for these transactions; and (v) promoting the use of hybrid instruments that combine the features of equity and debt, such as redeemable preference shares and convertible debentures.

F. Prerequisites for and planning of restructuring

24. The existence of well-defined property rights and mechanisms to enforce them, well-developed and efficient court systems, legal infrastructure, arbitration mechanisms, bankruptcy laws, and laws enabling

[13] Especially in the context of the inability of the governments to raise local currency-denominated power tariffs steeply and quickly under crisis conditions.

nondiscriminatory entry and exit of domestic and foreign investments are necessary prerequisites for fully restructuring the power subsector toward competition and consumer choice.

25. The creation of competitive power markets is not an activity that can be implemented in a few months. Going by the experience of several countries, it could take five years or more even in countries with an adequate and mature legal system and financial markets, and with well-organized public sector utilities functioning efficiently on commercial lines or with investor-owned utilities functioning under a regulatory regime. In countries where the legal and financial systems have to be created or improved, reformed, and allowed to mature, restructuring could take several more years. The period can also be made shorter when it is led by the head of state or a senior minister of the government, and by careful planning and building consensus regarding objectives and methods among all stakeholders (consumers; general public; political parties; affected parties, such as the exiting utilities, their staff, and financiers; IPPs; and nongovernment organizations specializing in energy and environment-related matters). Such stakeholder participation in the design of reform would help reconcile differences of approach, minimize opposition and obstacles to implementation, and make it broadly acceptable to large sections of the society. Securing such stakeholder participation and concurrence takes time and expenses in public awareness programs. The experience in many countries shows that, without such participation, restructuring runs into considerable difficulties.

26. Detailed planning for power subsector restructuring should cover a range of aspects such as (i) design and objectives of reform; (ii) amendment or repeal of existing laws preventing restructuring and enactment of necessary new laws enabling competition, independent regulation, etc.; (iii) establishment in the ministry of finance or in the office of the president or prime minister of a high-level empowered group to monitor and supervise restructuring; (iv) creation of a competent and independent regulatory body; (v) vertical and horizontal unbundling of the subsector, initially as business units with their own set of accounts; (vi) change from government style of accounting to commercial accounting in accordance with international accounting standards and generally accepted accounting practices; (vii) corporatization of the business units under the company law, with the government initially owning all the shares; (viii) introduction of independent external audit of the legal entities and subjecting them to

disclosure requirements of financial markets and security exchange commissions; (ix) commercialization of the operations of such legal entities by rationalizing tariffs[14] to cover supply costs and to provide reasonable return on the investment, and carrying out the urgently needed efficiency upgrades such as generation rehabilitation to improve heat rates, facilitate economic dispatch, reduce system losses, improve metering, billing, and collections and reduce account receivables, update property and inventory accounts, and revalue assets and debts; (x) privatization of the corporatized entities in generation and distribution activities to strategic investors through transparent ICB procedures; and (xi) settling the details and rules of the power pool, roles of the transmission company and central dispatch center, methods of dealing with stranded costs, and the role of the regulator vis-à-vis generation, transmission, dispatch, and distribution.

27. Parallel activities to be pursued outside the power subsector would be financial sector reforms to strengthen capital markets, long-term bond markets, and debt markets; and legal reforms to make the processes of bankruptcy and liquidation, arbitration, and commercial litigation resolution speedy, efficient, transparent, and fair. Antitrust laws to prevent unhealthy acquisitions and mergers inhibiting competition have to be enacted and arrangements made to enforce them. Procedures to deal with redundancy of staff arising from the privatization of public sector assets have to be developed in consultation with all stakeholders and put into operation.

G. Demand-side management and energy efficiency during restructuring

28. Questions have been raised as to whether power subsector restructuring on the lines discussed above would jeopardize the demand-side management (DSM) initiatives hitherto undertaken by vertically integrated utilities under the regulatory regime. Experience demonstrates that price-related DSM measures, such as prices reflecting costs of supply and prices varying as a function of supply costs over the duration of the day and the different seasons of the year, are fully achieved in competitive power supply. In the pool-based arrangement, dispatch is based on price bids received for each half-hour interval and the congestion pricing for the transmission and distribution services, as well as the uplift charge reflecting the

[14] It is also important to evolve transmission tariffs and distribution "wires" tariffs.

level of scarcity or otherwise of generation capacity at any time of the day.[15] Nonprice-related DSM initiatives could conceivably be undertaken by the transmission company and distribution company, which under a regulatory regime would have an obligation to provide "wires" services for the existing and future power demand, consistent with specified reliability levels. To the extent they could avoid system expansion capital costs by reducing demand in the franchise area, they could be obliged to evaluate DSM options in a fair comparison with system expansion alternatives (allowing adequately for environmental benefits) and undertake such measures if they turn out to be lesser cost options. Under such circumstances, the regulator could allow the expenses incurred in DSM activities to be included in the rate base of the transmission company or distribution company.

29. For a more sustained impact, energy use efficiency measures such as the use of improved motors, light bulbs, space heating, and space cooling, improvements to building designs, use of energy-efficient windows and more efficient insulation, and process changes in industry resulting in saving of energy use should be undertaken by private sector energy service companies (which operate as normal profit-seeking companies) by aggressively selling their energy-saving services on a contract basis, and sharing the benefits of energy cost savings with the client. The key limitation for the spread of such activities is the difficulty the companies face in raising finance, and multilateral development banks could help in promoting private sector funds that specialize in such transactions.

30. Further impetus for DSM will have to come from the manufacturers of energy-saving equipment or their trade associations through aggressive marketing and publicity. As a provider of public goods, the government-organized or sponsored energy conservation centers could carry out extensive public awareness campaigns on the need to improve energy use efficiency and the means available for this purpose.

31. Questions have also been raised that the power subsector reform based on competition may encourage the generation companies to increase generation from the old and highly fuel inefficient power plants with

[15] These DSM measures have been managed by load management, peak load shaving, peak load pricing, and seasonal tariff pricing initiatives under the regulatory regime.

low fixed costs. In a regulatory regime, rate of return-based regulation encourages the early retirement of old plants and the addition of new plants with higher fuel efficiency. It must, however, be remembered that the most commonly accepted criticism against rate of return-based regulation was that it provided incentives to create excess capacity at the expense of the consumer. The competitive regime corrects this major failing, and the continued use of inefficient plants may be an inevitable trade-off for the improvement. However, the problem could be mitigated by (i) removing subsidies on all fuels to allow prices to increase and thus penalize inefficient power generation; and (ii) adoption of stringent emission standards and enforcing them. If such inefficient units could produce energy within the strictly laid down and enforced emission norms, such generation could be considered acceptable.

32. Conversely, competitive power markets enable a more extensive use of the excess capacity available from captive power plants and cogeneration plants without the need for protracted contract negotiations with unwilling regulated utilities. Utilities regulated on the basis of rate of return tended to aggrandize their owned capacities and to spurn capacities owned by others. They tended to buy or import power only when it is inevitable. In the United States the Public Utility Regulatory Policy Act of 1978 was necessary to modify such behavior by utilities, obliging them to buy power from small producers if it was offered at or below the avoided cost of generation of the utility. In a competitive setup, captive power plants and cogeneration plants will face no entry barriers and can quote their prices for a given time interval and take their chances for dispatch. They could also seek long-term contracts with potential buyers using nondiscriminatory access to the transmission and distribution wires services. In the colder DMCs, such as the PRC, Mongolia, and the Central Asian republics, the waste heat from thermal power plants is used for district heating. In the warmer DMCs, industries requiring low pressure steam or hot water could set up power plants, sell electricity to the power pool, and use the spent steam or hot water for their process requirements. Similarly, power plants could sell spent steam or waste heat for purposes of district cooling using the services of energy service companies. Such developments are enabled and made easier in a competitive power subsector.

Promoting the use of renewable energy

A. The need for a level playing field

1. In respect of indigenously produced fossil fuels for domestic use, the rent (the difference between the economic cost of production and the market price) has to be recovered by the state appropriately through royalty, taxes, or production sharing. In many developing member countries of the Asian Development Bank, the petroleum subsector is taxed heavily and is a net contributor of revenue to the state. Such taxes need to be rationalized, taking care to ensure (i) that the overall present level of contribution of tax revenue does not decline; (ii) that the relative prices of oil, natural gas, and coal based on their inherent comparative advantage are not distorted; and (iii) that there is no bias against energy trade (imports or exports). Further, pollution taxes (or levies and charges) matching damage costs in respect of such pollutants as sulfur oxides, nitrous oxides, particulate matter, and toxic effluents, as well as emission-trading arrangements should continue so that the nonpolluting renewable energy options enjoy their comparative advantage of environmental friendliness.

2. In addition, there is a case for providing some financial support to renewable energy technologies because of their positive externalities, both locally and globally. At the global level, subsidies could come in appropriate forms from the Global Environment Facility, clean development mechanism, and other grant sources. At the national level, support could come from the state's general tax revenues or from surcharges levied on all fossil fuel options without distorting the relative prices of fossil fuels. In the United Kingdom, for example, a nonfossil fuel obligation program is followed, under which a small surcharge collected on all electricity consumption is applied to support the winners of competitive bids to supply electricity from renewable sources. Similar schemes exist in Europe, Japan, and United States, which have active public programs for developing renewable energy options.

B. Key barriers to renewables and possible solutions

3. Some of the key barriers to the financing of renewable energy projects are as follows:

(i) Because of the research and development efforts required to make available suitable technologies, renewable energy projects have very high front-end capital cost per kilowatt of installed capacity even though the variable costs for operation and maintenance are low. In

order to make the consumer price of such energy affordable, the debts need to have much longer maturity than is usually available in most capital markets.

(ii) Unlike conventional energy projects, renewable energy projects have very high project-development costs when compared with the actual project cost. This increases the penalty when developed projects cannot be implemented or are inordinately delayed for any reason.

(iii) The level of transaction costs such as due diligence for financing appear to be disproportionately high when compared with the project base cost.

(iv) It is difficult to forecast the cash flows of renewable energy projects. Energy output from renewable energy projects is linked to the availability of natural resources under specific parameters, such as water flow, wind speed, or solar radiation, which cannot be accurately predicted over the life of the project. Further, power purchase guarantees cannot be enforced on the numerous buyers, making it difficult to use nonrecourse project financing.

(v) Renewable energy project asset values are viewed with suspicion by the financing agencies, because they have limited marketability, compared with the assets of conventional energy projects.

4. Some solutions to these problems are emerging. For purposes of project preparation, evaluation, due diligence, and financing, transaction costs are lowered by standardizing modules and grouping a large number of standard modules in a financing package. Small, nongrid options such as micro hydropower, wind power, solar photovoltaic systems, or their hybrids with battery or diesel backup are mostly sold to individual consumers. In such cases the new approaches include (i) leasing the systems to end users rather than selling them, which overcomes the problem of high front-end cost and has been used, with some success, in India; (ii) financing vendor credit programs, and providing targeted credits to local development financing institutions to provide consumer credits as a part of renewable energy projects; (iii) dealing directly with renewable energy service companies, rather than end users; the companies install and maintain renewable energy systems and collect monthly charges for the use of the facility (somewhat like a capacity cost/kilowatt/month; such a mini-utility approach makes it easier to finance the company compared with assisting end users, and has been successfully employed in the Dominican Republic);

and (iv) incorporating such renewable systems as a part of home construction, the overall costs of such homes being eligible for mortgage or recourse financing. This last approach has been successfully used in South Africa.

5. In respect of small isolated grid systems, using renewable energy systems such as mini hydropower, biomass cogeneration, biogas, wind, solar, and diesel hybrid systems that are owned and operated by consumer-cooperatives, private entrepreneurs, or by renewable energy services companies allows for project appraisal and financing by local development finance institutions. Indonesia has used this approach with some success. Large-scale, grid-connected renewables such as wind power farms, solar thermal power, or captive power plants of sugar mills (using bagasse as fuel) have reasonable economies of scale and can be financed as long as project cash flows can be guaranteed. Such firm cash flows have been enabled, e.g., in India, by obliging the utilities (i) to buy the generated power at prices close to the average cost of the utility generation (somewhat like the legislation in the United States); (ii) to wheel the power to any customer of the renewable energy seller; and (iii) to act as an electricity bank to receive power as and when it is generated by renewable energy sources and sell it to the direct buyers in a steady fashion contracted by the renewable energy supplier. The last step could be resisted by the utility when the supply from such sources is large compared with its own generation.

6. The cost of capital can be lowered by lengthening the maturity of debts, allocating grant funds, and concessional funds (from the Global Environment Facility, clean development mechanism, and bilateral sources of assistance). Funds from the soft windows of multilateral development banks and the complementary financing scheme could prove useful. Such funds, however, may be channeled through appropriate local development finance institutions or other long-term credit-providing institutions to avoid getting involved in direct lending.

7. Finally, restructuring the power subsector by establishing competition and consumer choice could be a boon to well-run renewable energy suppliers (known as "green" power suppliers), as experience in several areas of Austria, Germany, Netherlands, Scandinavia, United Kingdom, and United States indicates that a large number of consumers contract for green power supplies through energy merchants, despite their higher price. This practice results in higher dispatch of the green power units compared with what had been possible in the past. The public awareness campaigns conducted by governments and, more importantly, by green-oriented nongovernment organizations have been largely responsible for such a consumer response. In areas where consumer choice is not yet available for all consumers, mechanisms such as nonfossil fuel obligation, public benefits wire charges, and renewable energy portfolio standards are used to enable better dispatch from green sources.

Regional cooperation and trade in energy

A. Overview

1. Complementarities in markets and resources have led neighboring countries to seek mutual solutions to meet their respective energy needs. For example, the People's Republic of China (PRC) has invested in Kazakhstan's oil production and is committed to developing railway and pipeline infrastructure for transporting oil to Xinjiang Autonomous Uygur Region. Uzbekistan is exporting natural gas through a pipeline to Kazakhstan and the Kyrgyz Republic. Kazakhstan is exporting coal to Uzbekistan and the Kyrgyz Republic. The Kyrgyz Republic is exporting electricity to Uzbekistan and Kazakhstan. Bilateral cooperation exists between Bhutan, India, and Nepal for electricity trade and the implementation of hydropower projects. The Lao People's Democratic Republic (Lao PDR) exports power to Thailand. Such regional energy trade in the Asian and Pacific region has considerable potential to expand.

2. As a cooperative multilateral institution, the Asian Development Bank (ADB) is uniquely placed to support regional cooperation activities aimed at removing transboundary constraints and creating transnational opportunities for economies in this region. The regional programs have involved the participation of several governments in planning and developing infrastructure and policies to benefit all participants. In the energy sector, the most significant of these programs have been in the Greater Mekong subregion, the Central Asian republics, and the South Asia Growth Quadrangle.

3. In the Greater Mekong subregion, a 210-megawatt (MW) hydropower project in the Lao PDR was completed in 1998 and, with its output being exported to Thailand, is making a significant contribution to the gross domestic product and foreign exchange earnings of the Lao PDR. Similarly, another 60-MW hydropower project for power export to Thailand, also located in the Lao PDR, was completed in early 2000.

4. Potential for regional energy trade also exists in the South Asia Growth Quadrangle, where Bhutan and Nepal have large surplus hydropower potential and border Bangladesh and India, which have large power requirements. Further, Bangladesh has considerable natural gas reserves that can be economically exploited to serve the large markets in neighboring India.

5. In Central Asia, Tajikistan and the Kyrgyz Republic with surplus hydropower potential, Uzbekistan with large natural gas reserves, and Kazakhstan with large proven coal deposits, complement each others' energy resource requirements. Tajikistan and the Kyrgyz Republic, with rivers fed by Himalayan glaciers, export surplus hydropower in summer to Uzbekistan and Kazakhstan, and import power during winter from the fossil fuel-based power plants in Uzbekistan and Kazakhstan. The power grid in these countries is interconnected by a 500-kilovolt (kV) transmission system, and its integrated operation gives rise to other benefits, such as reduced reserve margin (and consequently, lower capacity addition need) and lower overall system operating costs.

B. Key barriers

6. Despite the many benefits of intraregional energy trade, it can be constrained by a number of factors including the following.

(i) National policies generally favor self-sufficiency and import substitution at the expense of trade and rationalization of energy use. Taking Central Asia as an example, each country tends to encourage energy exports and discourage energy imports. These policies inhibit the rationalization of energy use, limit market size, and raise the real resource cost of energy for all the countries.

(ii) Physical infrastructure—such as new transmission pipelines and power generation and transmission lines, as well as improved railway capacity and storage facilities—are needed to expand energy trade. The high capital cost of these infrastructure projects and the long investment recovery period present considerable risks to the private sector. To mitigate the risk, most private infrastructure projects are financed through a combination of private and public funds. Consistency and transparency in government policies have become crucial in attracting and retaining private financing for infrastructure development.

(iii) While the neighboring countries are willing to assume a greater share of the ownership for future activities to promote regional cooperation, the limited financial resources available to participating governments often impede the process.

C. Outlook

7. Some specific energy projects that involve regional cooperation have been identified or proposed by the governments concerned for the Asian Development Bank's (ADB) consideration in the next three years. Technical assistance has been initiated to develop such projects. The major investment projects are as follows:

(i) Implementation of a natural gas transmission pipeline in Bangladesh that can eventually link to the larger market in India.

(ii) The feasibility assessments have been completed for the proposed Nam Ngum 3 Hydropower Project in the Lao PDR and the Nam Ngum to Udon Thani 500 kV transmission line in Thailand. The Se Kong-Se San River Basin Study (both in Cambodia and Viet Nam) has identified additional possibilities for hydropower developments.

(iii) In Central Asia, a project for rehabilitation and strengthening of the interconnecting power transmission grid is being prepared. Investment in this area will provide the basis for expanding electricity production and trade, as well as increasing the stability of the power system in the region. Another proposed project is for completion and renovation of the gas pipeline from Uzbekistan to the Kyrgyz Republic and Kazakhstan.

(iv) A gas transmission pipeline from Indonesia to Singapore is proposed for financing by international aid agencies and capital markets using the ADB guarantee under the Asian Currency Crisis Support Facility.

8. Experience has shown that regional cooperation is beneficial but slow to take effect. To ensure smooth and speedy implementation, issues that need to be addressed early in the development of cooperative projects include the legal framework, technical and commercial standards, environmental and social considerations, and risk-reward allocation.