ENERGY, ENVIRONMENT AND SUSTAINABLE DEVELOPMENT III

[ENERGY INFRASTRUCTURE POLICIES AND ISSUES]

ENERGY RESOURCES DEVELOPMENT SERIES
NO. 36

UNITED NATIONS

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PREFACE

The *Energy Resources Development Series* is a biennial publication of the Economic and Social Commission for Asia and the Pacific (ESCAP) which addresses a selected theme of current interest to analysts, policy makers and planners in the energy sector.

This publication, No. 36 in the series, takes up the theme of energy, environment and sustainable development for the third consecutive time. It is largely based on material presented at the Ad Hoc Expert Group Meeting on Energy Infrastructure and Energy Pricing Policies, held in Bangkok from 28 to 30 May 1997. Sustainable energy development and management are in many ways contingent upon the right pricing signals to the users. On the other hand, for investment purposes also, particularly for private sector participation in energy infrastructure, appropriate energy pricing is a prerequisite at a time when private sector funding is seen as a necessity to address the energy infrastructure bottleneck in social and economic development.

Most of the operational activities of ESCAP in the area of energy development and management rely on extrabudgetary sources of funding, multilateral funding from agencies such as the United Nations Development Programme and bilateral funding from sources such as the governments of Australia, China, France, Japan and the Netherlands. However, this publication and the senior expert group meeting which was the source of the material for it were part of the ESCAP regular programme of work for 1996-1997. It is the hope of the ESCAP secretariat that the publication will find a receptive and appreciative audience among its readers, relating, as it does, to the fine-tuning of infrastructure and pricing policies on energy development to the often elusive goal of sustainable development.

ABBREVIATIONS

ADB	Asian Development Bank
AIT	Asian Institute of Technology
APERC	Asia-Pacific Energy Research Centre
API	American Petroleum Institute
BOE	barrels of oil equivalent
CNG	compressed natural gas
DSM	demand-side management
ECDC	economic cooperation among developing countries
FAO	Food and Agriculture Organization of the United Nations
FDI	foreign direct investment
GDP	gross domestic product
GEF	Global Environment Facility
GNP	gross national product
GW	gigawatt
IPP	independent power producer
IRP	integrated resource planning
LPG	liquefied petroleum gas
LRMC	long-run marginal cost
MMTO	million metric tons of oil
MNCs	multinational corporations
NGO	non-governmental organization
NIE	newly industrializing economy
OECD	Organisation for Economic Cooperation and Development
OEG	oil equivalent gas
OPEC	Organization of Petroleum Exporting Countries
PACE-E	Programme for Asian Cooperation on Energy and the Environment
PSUs	public sector units
REDP	Regional Energy Development Programme
RFP	request for proposal
SAARC	South Asian Association for Regional Cooperation
SEB	State Electricity Board
T and D	transmission and distribution
TCDC	technical cooperation among developing countries
TCF	trillion cubit feet
TERI	Tata Energy Research Institute
TOE	tons of oil equivalent
TFEC	total final energy consumption
TPES	total primary energy supply
UNDP	United Nations Development Programme
UNIDO	United Nations Industrial Development Organization
WASP	Wien Automatic System Planning Package

INTRODUCTION

This year ESCAP has attempted to promote energy infrastructure services by providing a forum for energy experts to discuss relevant policy issues and identify options for decision makers. To that effect, the Ad Hoc Expert Group Meeting on Energy Infrastructure and Energy Pricing Policies (Bangkok, 28-30 May 1997) sketched some broad-brush scenarios for policy development in the light of the latest development in this field.

Asian economies, particularly the developing economies, are faced with the enormous problem of an energy infrastructure bottleneck, which is one of the major constraints on their sustained economic growth. This issue is even more critical today than before as these economies are increasingly opening up their energy industry to private sector participation. While this change has opened up an opportunity for access to private funding, managing the change properly has become more complex owing to often conflicting economic development and social objectives. The role of government and public utilities has also been changing from owner to rugulator and facilitator. Towards this process, one critical but sensitive area that needs reform is pricing policy. Other issues that have an influence on the energy infrastructure include environmental policy.

In the area of energy development and management, while there appears to be no immediate supply problem, the infrastructure bottleneck can only be addressed with a sound pricing and non-pricing policy in place. Energy infrastructure policy should include not only facilities for commercial energy resources, such as coal, oil, gas, hydro and nuclear, but also renewable energy resources that constitute the bulk of the energy supplies to rural areas. A number of economies in the Asian and Pacific region are experiencing higher energy demand growth than their infrastructure capacities can support. Many developing countries, moreover, still have large sections of their population which do not yet have access to commercial energy and some form of subsidy is still in place. Therefore, to meet the growing energy demand in a sustainable way, it is important to look carefully at various options available. Following the 1992 Earth Summit, a number of developing countries have taken positive steps in incorporating the environmental dimension in their energy policies and planning. These steps have been taken despite the awareness that additional costs will have to be incurred by consumers of energy because of the desirability, and indeed the necessity, to introduce, at an early stage, steps to protect the environment.

The Expert Group Meeting was organized to explore possible options for sound energy infrastructure development and pricing policies in response to global and regional environmental concerns and development needs. It was an appropriate forum to reflect on the ability to adjust and adapt an infrastructure policy to changing circumstances, or perhaps even to overcome problems. The conclusions and recommendations of the Meeting, as contained in chapter I, the report of the Ad Hoc Expert Group Meeting, capture very well the collective opinion of the experts on the energy infrastructure policy and issues in the Asian and Pacific region.

Other chapters of the book have been structured sequentially to assess the overall outlook and issues (chapter II), policy issues and management (structural changes in specific energy sub-sectors power, gas and renewable energy) (chapter III), energy infrastructure pricing policies and issues (chapter IV), and views of participants (chapter V).

PART ONE

REPORT OF THE AD HOC EXPERT GROUP MEETING ON ENERGY INFRASTRUCTURE AND ENERGY PRICING POLICIES, BANGKOK, 28-30 MAY 1997

A. ORGANIZATION OF THE MEETING

1. Attendance

The Ad Hoc Expert Group Meeting on Energy Infrastructure and Energy Pricing Policies was convened at Bangkok from 28 to 30 May 1997. It was attended by experts, including consultants and resource persons, from Bangladesh, China, India, the Islamic Republic of Iran, Malaysia, Nepal, Pakistan, the Republic of Korea, Sri Lanka and Thailand. An observer from the Petroleum Authority of Thailand also attended. Experts from the Asia-Pacific Energy Research Centre (APERC), Asian Institute of Technology (AIT), Economic Insight Inc. (EII), New Energy and Industrial Technology Development Organization (NEDO) and Tata Energy Research Institute (TERI) also participated.

2. Opening of the Meeting

In his opening statement, the Chief of the ESCAP Environment and Natural Resources Management Division noted that Asian economies, particularly the developing economies, were faced with the enormous problem of an energy infrastructure bottleneck, which was one of the major constraints on their sustained economic growth. Unless the energy infrastructure issue was managed fairly quickly and adequately, energy supply constraints might hinder further economic development. That issue was even more critical today than before as those economies were increasingly opening up their energy industry to private sector participation. While that change had opened up an opportunity to have access to private funding, managing the change properly had become more complex owing to often conflicting economic development and social objectives. The role of governments and public utilities had also been changing from owner to regulator and facilitator. Towards that process, he emphasized that the critical but sensitive area that needed reform was pricing policy. Other issues that had an influence on the energy infrastructure included environmental policy.

Almost all countries had problems with energy pricing; subsidies and cross-subsidies were often the norm rather than the exception. In that context, although some sort of assistance or discounts were needed for a section of people who otherwise might not be able to afford high energy costs, subsidies often benefited relatively better-off people than the target group. He suggested that one way might be to invest in projects for or to assist the target group in income-generation activities to build their capacity to pay.

3. Election of officers

The Meeting unanimously elected A.N.M. Rizwan (Bangladesh) Chairman, Amorn Phundhu-fung (Thailand) and Zhou Fengqi (China) Vice-chairmen, and Francis Xavier Jacob (Malaysia) Rapporteur.

4. Adoption of the agenda

The Meeting adopted the following agenda:

1. Opening of the Meeting.
2. Election of officers.
3. Adoption of the agenda.
4. Energy infrastructure outlook and issues.
5. Energy infrastructure pricing policies and issues.
6. Infrastructure policy options: institutional, pricing, the environment and fuel options.
7. Adoption of the report.

B. PROCEEDINGS OF THE MEETING

1. Energy infrastructure outlook and issues

(Item 4 of the agenda)

The Meeting had before it the secretariat document ENR/EGM/EIPP/1, entitled "Energy supply and demand trends in Asia and the Pacific" and document ENR/EGM/EIPP/2 covering the following topics: (a) policy issues and management of structural changes in the power sector; (b) structural changes in the gas sector; and (c) marketing renewable energy technology.

The purpose of the first paper was to highlight the latest energy supply and demand trends in the region. A brief analysis was also made of salient issues in the energy sector. The paper served as the background document, as the overall energy supply and demand trend had a direct linkage with energy infrastructure policies and issues. The focus of the second paper was on recent policy changes in the energy sector towards structural reform; the analysis covered relevant issues in the power and gas sectors as well as marketing renewable energy technology.

In the section on the power sector, the paper reviewed the power demand situation in the Asian and Pacific region and that was followed by an analysis of the structural changes that were taking place in the sector. Finally, the paper presented opportunities and challenges that the power sector was likely to face. In highlighting major policy aspects of structural adjustments, the paper concluded that the role of governments and/or utilities would remain critical, though the future role was likely to evolve from the current role of owner, planner, developer and service provider to perhaps that of regulator and facilitator. The paper saw increasing participation of the private sector, but pricing and regulatory reforms would be needed, or would need to be modified, by the receiving countries and utilities. Also in the pricing policy, efforts would be needed to minimize subsidies and cross-subsidies to make the utilities financially viable and, as far as possible, to internalize environmental costs for the benefit of the society. The paper suggested that each country should have its own strategy for private power according to the local situation. Wherever feasible, energy resource development, management, trade and exchange should be encouraged on a subregional basis for optimum utilization and mutual benefits to participating countries. The paper also gave a picture of future power needs in the region, and associated financing issues and environmental concern, which would have a consequence on fuel options for power generation. It was suggested that, in order to learn from each other's experience in managing the changes, regional and subregional cooperation was desirable.

With regard to the aspect of structural changes in the gas sector, the presentation covered the development of possible pipeline infrastructure in various subregions of Asia. It was argued that if the facilities were built on a subregional basis to serve more countries or markets from a joint network, the cost could be substantially reduced and projects become economically more attractive. For the promotion of further cooperation and manpower development, the possibility of establishing a training centre was raised.

In renewable energy technology promotion, the need for market development was emphasized for the sustainability of renewable energy projects. Renewable technologies, including solar PV, must gain markets if their large potential benefits were to be realized. As an example, the success of PV dissemination programmes was cited and was largely due to concentration on market development. The paper then suggested that barriers in marketing the technology should be effectively addressed to encourage market mechanisms to work.

Discussion

The point was raised as to whether or not it was advisable to allow private sector participation in transmission system development and management. It was felt that, in principle, there should be no limitation on private sector participation. One of the approaches that some countries were taking was unbundling the power sector into separate generation, transmission and distribution entities. In such a model the private sector might participate in any of the entities but governments might still like to keep control as a regulatory body. In that aspect, the Meeting felt that the financial viability of distribution agencies, including local power agencies such as state electricity boards in India, was critical for sustained private sector participation.

On another point, the choice of power wheeling or direct sales was discussed. The Meeting noted that power wheeling might be a preferred option for power transfer from one point to the other through a carrier (transmission system), which should be paid for its services. On the other hand, direct sales to customers in the vicinity of the generation, for example, from co-generation plants in an industrial area, might be better. In that respect, the representatives of the Electricity Generating Authority of Thailand shared its experience in having both models in operation in Thailand.

The Meeting noted that natural gas utilization in the region was likely to grow faster than other sources of energy. However, the current pricing system of gas put it as a more expensive option than coal. It was argued that the pegging of the gas price with furnace oil might need to be reviewed. On a point on the minimum off-take from a gas purchase agreement, it was felt that that might vary on the basis of how the risks were shared.

Highlights of the papers presented by the consultant from India, the resource person from the Tata Energy Research Institute (TERI) and experts from the Asian Institute of Technology (AIT), the Asia-Pacific Energy Research Centre (APERC) and EII are noted below.

Professor P.N. Agarwala, a consultant from India, presented his paper reviewing the status, policies and issues in energy infrastructure in the South Asian subregion. His review revealed that South Asia had serious problems of energy shortage owing to inadequate infrastructure. Acute problems of operational efficiency, high transmission and distribution losses, sub-optimal pricing and pilferage were common in many South Asian utilities. The paper suggested that distribution and generation/ transmission needed deregulation, allowing the development of professional management. The paper also suggested that energy infrastructure could be improved by retrofitting and modernizing. On the supply side, in the medium to long term, substitution of oil by coal, hydro and renewable sources was likely, but large investment would be needed with private/ foreign participation to help technological updating and revamping demand-side management. In the medium-term and long-term scenarios, it was stated that subregional cooperation was expected to play a greater role in the energy sector. The removal of environmental hurdles by streamlining clearance procedures was considered essential.

Rajnish Goswami, a resource person from TERI, presented his paper, which touched upon two aspects: India's macroeconomic outlook and, in that context, the energy demand and supply trends in India. Its energy sector was dominated by coal, with reserves expected to last for more than 200 years. However, oil and gas use in the economy had been increasing at a high rate. He concluded his presentation by highlighting the driving forces that would influence energy sector evolution in future, including the shifting role of the state from producer to regulator, deregulation, the need for finance, tackling subsidies, regional cooperation and meeting the environmental challenge.

On a question raised concerning the status of independent power producer (IPP) projects in India, clarification was given that the ENRON project had overcome the legal problems that it was facing and it was back on track after some delays. Regarding the private sector participation model, it was reported that several states in India were experimenting with different approaches within the overall framework of power sector reforms, with the assistance of the Asian Development Bank and the World Bank. It was also noted that a consensus had been reached at the political level by the Chief Ministers of all states in India on the reform and restructuring of the state electricity boards.

Professor Thierry Lefevre of AIT presented his experience in Asia on energy-environment planning followed by his idea of project activities that he thought would be useful for countries and the region in planning and implementing energy infrastructure facilities. The presentation focused on the long-term implications of the restructuring of the power sector in the Asian region and, in particular, on the social and environmental consequences of that process. On the environmental side, the following points were highlighted: (a) electricity pricing; (b) the future of modern renewable energy technologies; (c) power technologies and fuel choices; (d) development of newer clean technologies for power production; (e) promotion of energy efficiency; and (f) effects of short-term ownership on long-term environmental impacts. On the social side, the following implications were underlined: (i) access to electricity by the poor in the framework of liberalization on electricity tariffs and its eventual social consequences; (ii) the consequence of switching to cheaper energies (traditional, mainly wood, charcoal etc.) with its environmental implications (urban air pollution and deforestation); and (iii) the future of rural electrification programmes and their consequences on the use of new and renewable technologies and eventually on the economic and social development of rural areas.

Following the presentation of the possible main impacts of the restructuring of the power sector, Professor Lefevre presented two regional projects which could be developed in the framework of future ESCAP activities for which financial resources should be raised. Those projects were (a) the environmental and social implications of power sector restructuring in Asia; and (b) the development of a methodology for the monetary valuation of environmental damage caused by air pollution from power generation in developing countries and its application.

Some concern was expressed that, with increased private sector participation, demand-side management (DSM) measures might not be pursued by the IPPs. However, the other view was that, in an unbundled environment, perhaps energy service companies might come in to provide DSM services. The representative of the Department of Energy Development and Promotion of Thailand described its experience in the DSM programme initiated in Thailand; the programme had to be introduced through a government regulation. Another view was expressed that perhaps technological improvements would take care of some efficiency concerns. It was, however, noted that regulatory measures and incentives were also needed to promote efficient utilization of energy.

A paper on recent moves around IPPs in Japan was presented by Taizo Hayashi of APERC, based in Japan. The recent introduction of IPPs in Japan was characterized as one of the series of initiatives aimed at re-engineering the electric power industry. In that respect, it was necessary to understand it properly in the programme of economic structural reform. He held the view that, to remain cost-competitive in global mega-competition, IPP-related private companies were expected to go abroad for business opportunities, especially in the Asian region. On the other hand, however, it might be desirable to establish some kind of assistance from, or cooperation with, the public sector in terms of financial assistance or consolidating investment environment as well as similar efforts for recipient developing countries.

Ronald D. Ripple of EII, United States of America, gave a presentation on his research work concerning the status, prospects and issues in private power in Asia. His findings were that the current share of IPPs in Asia amounted to about 2 per cent over the region, with most individual countries limited to under 10 per cent IPP share of the total capacity. By 2005, the regionwide role was expected to rise to about 20 per cent, with nearly all economies which currently had active IPPs increasing to over 25 per cent. IPP participation through 2005 in 11 Asian economies would amount to over 200 GW, of an expected total expansion of 550 GW.

Mr Ripple further noted that "deregulation" was not really applicable to most circumstances in Asia. In fact, what would be needed was the establishment of a regulatory regime that would provide oversight as the asset ownership moved from public to private hands. He noted that agreements under way would provide the basis for an international natural gas grid in South-East Asia.

In reply to a question that private sector participation generally led to higher electricity prices, he stated that, since the current price was already at a low level with subsidies in place, initial private power projects might lead to a price jump to compensate for the various risks involved. On another point on privatization to start from distribution followed by IPP generation, it was felt that foreign participation was doubtful given the uncertainties involved. On the question of multiple transmission companies in a country, it was felt that for larger countries such as China and India, it might be possible, provided that a common regulatory structure was in place. However, there was a risk of buy-out by large IPPs leading to a possible monopoly.

2. Energy infrastructure pricing policies and issues

(Item 5 of the agenda)

Professor Shankar P. Sharma, a consultant to the secretariat, presented his paper on the topic. The paper focused on pricing policies and issues of energy infrastructure in response to development needs and global and regional environmental concerns. The analysis covered policies, market pricing, and regulatory pricing, including subsidies and cross-subsidies. Mobilizing financial resources to meet the growing investment need had become the major concern in most of the developing countries. The demand for energy, including electricity, was growing rapidly. The magnitude of financial resources required to meet the projected demand would be enormous. Distorted energy pricing policy was the main impediment to the private sector's participation in energy infrastructure development. The retail price of energy had been kept low in many developing countries. Energy output prices were subsidized explicitly (opportunity cost of capital was not taken into consideration) or implicitly (mainly foreign exchange risks were not taken into consideration). The prices of energy between countries and between sectors were different. The implications of energy pricing on private sector investments were discussed and some suggestions made to rectify various issues. Pricing policy would have to be changed in those countries if they wanted to increase the private sector participation in the energy sector. The private sector could participate in energy development only when the energy prices would be adequate to cover all costs of energy generation.

Romeo Pacudan of AIT shared the findings of his research on the options and implications of internalizing the environmental costs of power projects in pricing. In order to mitigate the environmental damage associated with the generation of power, there had been some attempts to strengthen policies and regulations be reflecting the related environmental costs in monetary terms. However, it appeared that the attempts so far had not produced sufficient results to warrant their effectiveness for the inclusion of such a concept into regulations, as seen in some cases in the United States of America. In the Asian and Pacific region, incorporating environmental costs in the decision-making process had still a long way to go. In the meantime, the governments of the region could strengthen their existing environmental policies and could perhaps adopt other market-based policies in order possibly to achieve environmental goals at least cost. Further, in the light of the dire need of private capital in power supply expansion in many countries, environmental policies must meet both environmental and investment goals. To meet those objectives, the principles of consistency, transparency, clarity, cost-effectiveness and timeliness should guide the development of environmental practice in the planning, development and operation of electricity infrastructure.

R.M. Shrestha of AIT presented findings of a research study undertaken by AIT entitled "Issues in avoided cost pricing of IPP power: a sensitivity analysis". The presentation covered various approaches for pricing IPP power: individual negotiation, competitive bidding and standard offer by utility, or a combination of all those. He then shared the results of the sensitivity analysis, which showed effects of variations in discount rate, level of IPP power, power purchase contract duration and load growth. The presentation was followed by discussions and clarification on the avoided cost approach, which might represent only average cost and should serve as an upper bound for a negotiated IPP price. There was also a discussion on the limitation of Wien Automatic System Planning (WASP) model application in a hydro-dominated system.

Country presentations

The country presentations covered both agenda items 4 and 5, covering status, policies and issues of infrastructure, including pricing policies. Highlights of the major points are presented in the following paragraphs.

The participating experts from Bangladesh, China, India, the Islamic Republic of Iran, Malaysia, Pakistan, the Republic of Korea, Sri Lanka and Thailand presented their respective country reports. In their papers and presentations, the experts described and analysed the main characteristics of the current national energy demand and supply situation. The participants also presented alternative economic and energy sector development scenario forecasts, and introduced the main elements characterizing current or recommended future national policies and strategies for energy sector and energy infrastructure development, aimed at meeting the expected growth in energy demand in the near and intermediate term. The country reports invariably confirmed the strong correlation between economic development and energy consumption. In many countries, energy sector development had therefore been identified as a priority area, as the stable, sufficient and affordable supply of commercial energy remained an essential precondition for economic development.

In some countries, institutional reforms and reorganizations were under way, including some legislative initiatives aimed at facilitating and attracting private sector investment in the development of the power sector infrastructure. In some Asian countries, IPPs already played an important role in electricity generation, while in other countries, the entire electricity generation, transmission and distribution system remained under the management and ownership of government establishments. Several participants mentioned the difficulty of attracting private investment into the financially much less attractive areas, such as transmission and distribution.

In several of the participating countries, energy development and energy pricing policies were currently under review or reformulation. In several countries, electricity pricing was being reviewed with a view possibly to reducing overall levels of subsidization. Pricing policies, government regulatory mechanisms and non-energy policy priorities varied among countries, as well as among different fuel types. In all countries, electricity tariffs were established and periodically reviewed by the competent state regulatory bodies and approved by government. Pricing of petroleum products was often relatively more liberal, but prices were largely influenced by energy consumption taxes. As far as petroleum products were concerned, price regulation and cross-subsidization (generally in favour of kerosene and diesel) were expected to be maintained, as those were often considered a useful tool for the achievement of non-energy development policy objectives, such as social goals, or as support to certain economic sectors (that is, agriculture, small-scale industries, and public transport).

Some of the country reports also included reference to integrated resource planning (IRP) and DSM as important tools possibly to curb the expected future growth in energy and electricity consumption. Some experts mentioned the need for governments to support utilities financially to absorb some costs and eventual (temporary) losses which might result from DSM implementation. Some countries, such as the Republic of Korea and Thailand, had introduced legislation which earmarked a certain percentage of petroleum consumption tax revenue as a funding source for national energy conservation funds.

In the discussion session that followed all presentations by the secretariat, resource persons, consultants, representatives of other organizations and countries, several points were raised for clarification or further elaboration. The secretariat, as well as a number of experts, shared their views on those points. Some of the major areas of discussion are noted below.

Discussion focused on exchanging country experiences in the area of negotiating power purchase agreements. In some countries, initial contracts with private power producers were obliged to include legal clauses which were felt to be unfair as they allowed investors to transfer most, if not all, incalculable investment risks to the host government. Participants expressed their concern on the "force majeure" clause, which IPP investment partners often sought to pass on to governments. Among the other issues discussed were subregional gas pipeline projects in South Asia which would require government approval from participating countries. The potential economic benefits of the development of subregional cooperation were noted. Participants also discussed in more detail the social aspects of energy pricing, price and income elasticities of energy consumption and consumer responses to pricing policies and energy price adjustments. Participants from China, Malaysia and Thailand provided supplementary information on the involvement of private investors in coal mining, oil refineries and hydropower projects.

3. Infrastructure policy options: institutional, pricing, the environment and fuel options

(Item 6 of the agenda)

The agenda item was introduced by the secretariat, which emphasized that, after the contributions of all the expert participants, there was a need to list issues and options so that, eventually, recommendations could be made on how to address the problems identified. The secretariat then summarized policy options on energy infrastructure based on the deliberations on agenda items 4 and 5. A very lively discussion followed, in which especially pricing policy and subsidy issues were deliberated upon, since those were considered to be at the centre of infrastructure investment and financing viability.

The Meeting noted that, while in many regional countries there were constitutional guarantees for the population to benefit from energy resources through a "right to access", in practice, at what could be considered commercial rates for electricity and some energy products, large segments of the less advantaged members of the population would be excluded from such access. Thus, governments often subsidized such access through lower preferential tariffs for some segments of the population. Such a practice would render electricity utility companies financially weak, since tariffs on the average would often fall short of the commercial rates needed to cover operational and investment requirements. At the same time, it was argued that investment requirements were increasing at a rate unlikely to be met by public capital resources alone in those growing economies where the elasticity for electricity demand was larger than unity, meaning that the demand for high-grade energy would outstrip economic growth percentages and that, additionally, some suppressed demand would still exist because of comparatively high tariffs, even at subsidized rates.

A part of the solution to the capital shortage problem was believed to lie in international private capital, through IPPs that would enable infrastructure investment to proceed by tapping lower-cost international capital markets, provided that contractual relations in terms of power purchase agreements and fuel supply agreements evolved in such a way that commercial returns became possible for such investors, who could often take advantage of the most efficient technology and processess to supply power into the grid at competitive costs. It was emphasized by the participants that, although such a procedure might lead to an estimated share of IPPs in the generation capacity in the Asian and Pacific countries in the range of 10 to 20 per cent of the total market, the problem of linking the suppliers with the customers would still have to be controlled by the government to fulfil constitutional obligations. Independent regulatory commissions might fulfil such a function as was evolving, for instance, in Bangladesh and India. The basic problem, however, might still remain that, as long as economic growth did not result in sufficiently rapid poverty reduction, some customers would still need subsidies. Cross-subsidization among customers might work in some cases. However, such cross-subsidies would need to be sharply targeted and monitored.

Direct sales by IPPs to some industrial customers might work to render IPPs viable, as shown in Andhra Pradesh in India. In other cases, although such offers were given by some governments, potential foreign investors showed a preference for selling to a national transmission/distribution company because of the implicit government guarantee of off-take in the latter case.

Examples of contract negotiations, lasting from two years (Andhra Pradesh in India) to 45 days (Bangladesh), highlighted the practical problems in finalizing such deals. The learning process through more long-term negotiations was thought to be worthwhile, while at the same time competition introduced via a bidding process at a later stage could take advantage of such knowledge gained.

Questions concerning hydropower as IPP were answered by Malaysia, emphasizing the uniqueness of the Bakun scheme involving both generation and transmission, directly negotiated with a private investor.

It was emphasized that, although transmission might be a natural monopoly, it could still be successfully offered for private sector participation. Tariff-setting within a national grid, as it evolved through interconnected transmission links, might be less of a problem for the "transmission fee". Experience in Oregon in the United States, where surcharges on such transmission fees served the revenue needs of the government to meet social and environmental objectives, demonstrated the feasibility of such an option.

4. Conclusions and recommendations

Based on the above deliberations, the Meeting came to the following conclusions and made the following recommendations:

(a) Inadequate energy infrastructure in many developing countries was a bottleneck in social and economic development, in terms of both quantity and quality of energy services. Greater attention needed to be given to developing and strengthening the energy infrastructure, not only through adding additional facilities but also through retrofitting and better management of existing facilities in order to meet the future demand;

(b) Financing remained a critical issue in energy infrastructure developments. Countries that were short of capital funds were often unable to attract private investment for various reasons: (i) perceived political risk; (ii) lack of transparent rules and regulations; (iii) lack of depth in the local financial market; (iv) financial risk; (v) poor creditworthiness of utilities: inefficiency in operation and maintenance, revenue collection far below the desirable limit, and unremunerative tariffs;

(c) The role of governments and utilities would remain critical, though the nature of the role was expected to change from energy developer and service provider to planner, regulator and facilitator;

(d) Energy for social services (for example, rural electrification, energy supplies to the poor) would remain a challenge to government policy, as that aspect was unlikely to be covered by the private sector;

(e) Energy pricing was an important but complex issue that needed to be carefully reviewed and formulated or adjusted to meet the economic and social objectives of countries based on the situation and need of individual countries. Market distortions through subsidies should be gradually reduced and eventually phased out. As far as practicable, environmental costs should be taken into account;

(f) In most countries, policies in one form or the other existed to encourage and attract private sector investment in providing energy services. Transparency of the policies, including risk-sharing, needed to be ensured. A partnership approach should be taken. Any constraints on private sector participation in energy development and management should be addressed by, among other things, restructuring and reform;

(g) Optimization of resource development, management and utilization through regional, subregional cooperation on economic merits and development and exchange/trade of energy should be encouraged;

(h) Human resources development, through sharing and exchange of experience, technical cooperation among developing countries and training, was an important element in adopting and managing structural changes in the energy sector;

(i) All-out efforts should be made to encourage energy conservation and end-use energy efficiency through measures such as demand-side management. While developing countries needed to use more energy for further socio-economic development, system losses should be reduced and wasteful uses eliminated;

(j) Environmental concern would influence future energy mix and technology options. While fossil fuel would continue to be the dominant fuel for large-scale applications, particularly in power generation, environmentally benign energy such as hydro (with proper environmental measures) and other renewable energy (solar, wind, biomass, etc.) would increasingly be preferred. Clean-coal technology and renewable energy technology would play a larger role in fuel mix in the next century.

5. Adoption of the report

(Item 7 of the agenda)

The Meeting adopted its report on 30 May 1997.

PART TWO

ENERGY INFRASTRUCTURE OUTLOOK AND ISSUES

I. ENERGY SUPPLY AND DEMAND TRENDS IN ASIA AND THE PACIFIC*

INTRODUCTION

The purpose of the present paper is to highlight the latest energy supply and demand trend in the region, followed by a brief analysis of salient issues in the energy sector. While discussing energy infrastructure, it is important to look at the energy supply and demand situation as it has a direct linkage with the energy policies and issues.

A. ENERGY RESOURCES AND SUPPLIES

Table I.1 shows the energy reserve situation in the world as well as in the Asian and Pacific region as of the end of 1995. It may be noted here that the relative composition of reserves in Asia and the Australasia subregion was very similar to that of the world; the reserve production ratio[1] of coal was the highest (158) followed by natural gas (45.8) and oil (17.0).

Table I.2 shows the energy production history in the Asian and Pacific region.

B. REGIONAL ENERGY DEMAND SCENE AND TRENDS

Analysis of the aggregate energy scene does not capture the individual situation at the country level. Nevertheless, it captures the general trend of energy demand, which influences the energy market and pricing as many of the countries are energy-importing

* ESCAP secretariat.

1 The reserve/production ratio takes into account only the current production figure in its calculation. Moreover, it is based on a price assumption that may change in the future. Nevertheless, it is a fairly good indicator showing a probable scenario under certain basic assumptions.

Table I.1 World proven reserves of fossil fuels, end 1995

	Oil		*Natural gas*		*Coal*	
	Amount (billions of tons)	*Reserves/ production ratio (in years)*	*Amount (trillions of cubic feet)*	*Reserves/ production ratio (in years)*	*Amount (billions of tons)*	*Reserves/ production ratio (in years)*
World	138.3	42.8	4 933.6	64.7	1 031.6	228
Organisation for Economic Cooperation and Development	14.0	14.7	491.2	14.4	424.4	248
Organization of Petroleum Exporting Countries	105.8	79.5	..	..	..	..
Asia and Australasia (including China but excluding the Middle East)	6.1	17.0	328.6	45.8	311.5	158
China	3.3	22.0	59.0	94.9	114.5	88
Middle East	89.2	92.3	1 597.2	> 100		
Islamic Republic of Iran	12.0	65.9	741.6	> 100	..	..

Source: *BP Statistical Review of World Energy 1996*, June 1996.

Notes: Proven reserves are generally taken to be those quantities which geological and engineering information indicates with reasonable certainty can be recovered in the future from known reservoirs under existing economic and operating conditions.

Reserves/production ratio: If the reserves remaining at the end of any year are divided by the production in that year, the result is the length of time that those remaining reserves would last if production were to continue at the then current level.

Reserves tabulated under various groups of economies are not mutually exclusive as there are overlaps among some groups.

Table I.2 Production of commercial primary energy in the ESCAP region, excluding the Central Asian republics
(Millions of tons of oil equivalent)

	1970	1973	1975	1980	1985	1990	1993	1994	Average annual growth rates (percentage) 1980/ 1970	1990/ 1980	1990/ 1970	1994/ 1993
Solids	302.0	337.4	372.1	460.4	664.3	847.8	936.7	995.2	4.3	6.3	5.3	6.2
	(48.3)	(39.6)	(41.5)	(52.6)	(54.6)	(51.4)	(52.5)	(52.6)				
Liquids	283.5	457.7	452.2	318.1	395.8	503.5	529.7	542.8	1.2	4.7	2.9	2.5
	(45.3)	(53.7)	(49.8)	(36.3)	(32.6)	(30.8)	(29.7)	(28.7)				
Gas	23.8	39.2	50.2	65.3	109.9	169.4	186.4	216.1	10.6	10.0	10.3	15.9
	(3.8)	(4.6)	(5.6)	(7.5)	(9.0)	(10.4)	(10.4)	(11.4)				
Electricity	16.3	17.7	22.4	31.9	45.8	114.0	132.1	139.2	6.9	13.6	10.2	5.4
	(2.6)	(2.1)	(2.5)	(3.6)	(3.8)	(7.0)	(7.4)	(7.4)				
Total	625.7	852.1	896.9	875.6	1 215.8	1 634.7	1 785.0	1 893.3	3.4	6.4	4.9	6.1
	(100)	(100)	(100)	(100)	(100)	(100)	(100)	(100)				

Source: United Nations, *Energy Statistics Yearbook*, various issues.

Note: The figures in parentheses show the share as the percentage of the total.

countries and only a few of them are energy exporters. The region as a whole remained a net energy importer for a long time and the gap between energy consumption and production has generally been rising. As of 1994, the commercial energy consumption was 2,069.7 MTOE compared with a production of 1,893.3 MTOE.

1. Aggregate commercial energy demand

The latest trend of consumption of all forms of commercial primary energy in the ESCAP region and aggregate world trends indicate that regional primary energy consumption has been increasing at an average annual rate of 5.2 per cent over the last two decades; the world average growth rates were only 2.9 and 2.6 per cent during the same period. The regional (excluding the Central Asian republics) total commercial energy consumption in 1994 reached 2,069.7 MTOE, up from 1,937 MTOE in 1993, registering the highest annual growth of 6.9 per cent so far in the current decade. Whereas the consumption in the industrialized economies of the region during the period 1970-1990 increased by about 3.2 per cent a year, that of the developing economies increased at an average annual rate of 6.3 per cent. Despite this impressive growth in developing economies, the current energy consumption level in developing countries remained quite low compared with the industrialized countries. The per capita energy consumption in 1994 in developing economies (excluding the Central Asian republics) was only 502 kgoe compared with the world average of 1,395 kgoe and that of the ESCAP developed economies 3,719 kgoe.

Tables I.3 and I.4 show the historic energy demand situation and demand pattern in the region, while table I.5 shows energy demand patterns in developing economies.

2. Dominance of fossil fuel in demand structure

In 1994, over 93.3 per cent of the total commercial energy demand in the region was met by fossil fuel, namely, solids (mainly coal), oil and (natural) gas. Historically, solid fuels have had the largest share of consumption in the region; except in a few years in the 1970s when the share slipped, it maintained a share of around 50 per cent in total commercial energy consumption. The share of liquid fuels declined significantly, from a high of 48.5 per cent in 1973 to 32.8 per cent in 1988. Since then the growth in the liquid fuel share has been showing signs of regaining a part of its lost share; it increased gradually to 33.7 per cent in 1994.

Table I.3 Consumption of commercial primary energy in the ESCAP region and the world
(Millions of tons of oil equivalent and kilograms of oil equivalent per capita)

	1970	1973	1975	1980	1985	1990	1993	1994	Average annual growth rates (percentage) 1980/1970	1990/1980	1990/1970	1994/1993
World	4 433.5 (1 212)	5 115.6 (1 322)	5 121.7 (1 267)	5 891.5 (1 339)	6 449.1 (1 326)	7 605.2 (1 432)	7 702.3 (1 385)	7 880.6 (1 395)	2.9	2.6	2.7	2.3
ESCAP region	624.7 (330)	793.3 (373)	848.7 (378)	1 038.1 (430)	1 296.8 (478)	1 723.2 (576)	1 937.0 (615)	2 069.7 (649)	5.2	5.2	5.2	6.9
Developed economies of the ESCAP region	265.3 (2 224)	334.5 (2 675)	329.9 (2 569)	363.2 (2 700)	402.9 (2 899)	496.8 (3 455)	520.8 (3 576)	543.6 (3 719)	3.2	3.2	3.2	4.4
Developing economies of the ESCAP region[a]	359.4 (191)	458.8 (229)	518.8 (245)	674.9 (295)	894.0 (347)	1 226.4 (431)	1 416.2 (472)	1 526.2 (502)	6.5	6.2	6.3	7.8
Central Asian and Turkey							209.60 (3 276)	196.10 (3 017)				(6.4)

Source: United Nations, *Energy Statistics Yearbook,* various issues.

Note: The figures in parentheses show the per capita energy consumption.

[a] Excluding the Central Asian republics and Turkey.

Table I.4 Consumption pattern of commercial primary energy in the ESCAP region, excluding the Central Asian republics
(Millions of tons of oil equivalent)

	1970	1973	1975	1980	1985	1990	1993	1994	Average annual growth rates (percentage) 1980/1970	1990/1980	1990/1970	1994/1993
Solids	319.0 (51.1)	360.1 (45.4)	392.0 (46.2)	487.9 (47.0)	688.3 (53.1)	859.8 (49.9)	951.3 (49.1)	1 014.0 (49.0)	4.3	5.8	5.1	6.6
Liquids	268.7 (43.0)	385.1 (48.5)	393.6 (46.4)	452.4 (43.6)	456.3 (35.2)	577.1 (33.5)	663.6 (34.3)	696.6 (33.7)	5.4	2.5	3.9	5.0
Gas	21.3 (3.4)	30.4 (3.8)	41.4 (4.9)	66.0 (6.4)	106.6 (8.2)	172.3 (10.0)	189.9 (9.8)	219.5 (10.6)	12.0	10.1	11.0	15.6
Electricity	15.7 (2.5)	17.8 (2.2)	21.7 (2.6)	31.8 (3.1)	45.7 (3.5)	114.0 (6.6)	132.2 (6.8)	139.6 (6.7)	7.4	13.6	10.4	5.6
Total	624.7 (100)	793.3 (100)	848.7 (100)	1 038.1 (100)	1 296.8 (100)	1 723.2 (100)	1 937.0 (100)	2 069.7 (100)	5.2	5.2	5.2	6.9

Source: United Nations, *Energy Statistics Yearbook,* various issues.

Note: The figures in parentheses show the share as the percentage of the total.

Table I.5 Consumption pattern of commercial primary energy in developing countries of the ESCAP region, excluding the Central Asian republics
(Millions of tons of oil equivalent)

	1970	1973	1975	1980	1985	1990	1992	1993	Average annual growth rates (percentage) 1980/1970	1990/1980	1990/1970	1993/1992
Solids	239.9 (66.8)	285.9 (62.3)	316.9 (61.1)	404.4 (59.9)	581.3 (65.0)	740.3 (60.4)	796.6 (59.4)	834.0 (59.0)	5.4	6.2	5.8	4.7
Liquids	96.4 (26.8)	142.4 (31.0)	163.5 (31.5)	222.2 (32.9)	240.1 (26.9)	335.7 (27.4)	394.1 (29.4)	416.5 (29.5)	8.7	4.2	6.4	5.7
Gas	17.4 (4.6)	22.0 (4.8)	28.9 (5.6)	34.3 (5.1)	51.2 (5.7)	103.5 (8.4)	101.7 (7.6)	110.6 (7.8)	7.6	11.7	9.6	8.8
Electricity	6.6 (1.8)	8.5 (1.9)	9.5 (1.8)	14.0 (2.1)	21.3 (2.4)	46.9 (3.8)	48.7 (3.6)	52.6 (3.7)	7.8	12.8	10.3	7.9
Total	359.4 (100)	458.8 (100)	518.8 (100)	674.9 (100)	894.0 (100)	1 226.4 (100)	1 341.1 (100)	1 413.8 (100)	6.5	6.2	6.3	5.4

Source: United Nations, *Energy Statistics Yearbook*, various issues.

Note: The figures in parentheses show the share as a percentage of the total.

Central Asian republics figures in 1993: Total, 163,414, Solids, 51,243, Liquids, 41,193, Gas, 66,161, and Electricity, 4,817 thousand toe.

3. Influence of a few economies on the regional demand structure

Although solids appear to be the dominant fuel (58.1 per cent as of 1994) for the developing economies, when China, India and the Central Asian republics are excluded the regional share of solids drops to 22 per cent and that of liquids rises to 51 per cent. Gaseous fuel has established a strong presence in the regional energy mix by steadily increasing its share from only 3.4 per cent in 1970 to 10.6 per cent in 1994. Its growth rate has been particularly impressive (10-12 per cent) during the last two decades.

4. Share of primary electricity in the energy demand

The regional share of primary electricity in the total commercial energy demand was 6.7 per cent in 1994; its growth rate over the last year was only 5.6 per cent. The electricity demand situation has been discussed in a separate paper.

5. Energy demand projection

The result of ESCAP work on the revised (1996) projection of the likely energy demand of countries in the Asian and Pacific region reveals the following. In the business-as-usual scenario, the annual growth rate of commercial energy consumption in developing economies of the region is projected to remain close to the level of the past trend of the 1970s and 1980s, at 6.3 per cent for the period 1993-2000, then decline to 5.2 per cent during the period 2000-2010 and further to 4.6 per cent during the following decade. The revised projection, which takes into account the latest economic growth in a number of economies which is better than expected, shows higher energy demand than had been forecast earlier. In the energy conservation and efficiency scenario, the annual growth rate is expected to be 5.7 per cent for the period 1993-2000, 4.9 per cent for the period 2000-2010 and 4.4 per cent for the period 2010-2020. These growth rates are somewhat higher than the global fossil fuel energy projections of 4.2 per cent for the period 1990-2020 for developing countries.[2] However, it is considered reasonable given the fact that the Asian and Pacific region is the most dynamic growth region of the world. The improved economic outlook for the latter part of the 1990s owing to prospective higher growth to be attained by the industrialized economies, greater global trade liberalization now in progress, and the successful economic reforms being undertaken by a number of countries justify the higher energy demand projection.

[2] Energy and sustainable development: issues concerning energy development, with particular emphasis on developing countries report of the Secretary-General for the first session of the Committee on New and Renewable Sources of Energy and on Energy for Development, New York, 1994 (E/C.13/1994/2).

Table I.6 Primary commercial energy consumption and scenarios S1 and S2 to the years 2000, 2010 and 2020
(Thousands of tons of oil equivalent and percentage)

Subregions of Asia and the Pacific	*Consumption*		*Projections*						*Average annual growth rate (percentage)*					
	1983	*1993*	*2000:S2*	*2000:S1*	*2010:S2*	*2010:S1*	*2020:S2*	*2020:S1*	*1993-2000:S2*	*1993-2000:S1*	*2000-2010:S2*	*2000-2010:S1*	*2010-2020:S2*	*2010-2020:S1*
	(1)	(2)	(3)	(4)	(6)	(7)	(8)	(9)	(10)	(11)	(12)	(13)	(14)	(15)
East and North-East Asia	522 802	898 045	1 344 000	1 397 300	2 142 000	2 258 000	3 172 000	3 369 000	5.9	6.5	4.8	4.9	4.0	4.1
South-East Asia	88 132	175 145	288 900	302 700	505 000	553 000	838 000	961 000	7.4	8.1	5.7	6.2	5.2	5.7
South and West Asia[a]	173 806	385 780	572 500	594 600	961 000	1 021 000	1 594 000	1 734 000	5.8	6.4	5.3	5.6	5.2	5.4
Central Asia	0	163 417	188 700	201 000	254 000	297 000	341 000	440 000	2.1	3.0	3.0	4.0	3.0	4.0
Pacific	2 809	2 705	3 110	3 220	4 000	4 300	5 000	6 000	2.0	2.5	2.5	2.9	2.3	3.4
Total Asia and the Pacific														
Developing economies	787 549	1 625 092	2 397 210	2 498 820	3 866 000	4 133 300	5 950 000	6 510 000	5.7	6.3	4.9	5.2	4.4	4.6
Industrialized economies	395 000	565 000	647 000	669 000	739 100	806 000	824 000	945 000	2.0	2.4	1.3	1.9	1.1	1.6
Grand total Asia and the Pacific	1 182 549	2 190 092	3 044 210	3 167 820	4 605 100	4 939 300	6 774 000	7 455 000	4.8	5.4	4.2	4.5	3.9	4.2

Source: ESCAP secretariat, based on United Nations, *Energy Statistics Yearbook,* World Bank, *World Tables* and International Energy Agency, World Energy Outlook, 1996.

[a] Including the Islamic Republic of Iran and Turkey only from West Asia.

Scenarios: S1: Business-as-usual scenario assuming that the past trend will continue.

S2: Energy conservation and efficiency scenario.

Table I.6 gives the energy demand projection of the region with a breakdown on a subregional basis.

6. Rural energy supply

More than half of the population in many countries of the Asian and Pacific region is still dependent on traditional sources of energy, such as firewood, and animal and agricultural wastes. Even in partially industrialized countries such as India, Indonesia, Pakistan and Thailand, more than 20 to 30 per cent of the total energy requirements are still met by these fuels. Rural energy demand can be met from the supply of both new and renewable sources of energy and commercial fuels. An appropriate energy mix is needed for different locations, taking into consideration the substitutability and complementarity of different sources of energy. For example, crop residues, animal dung and biogas can be used as substitutes for fuelwood; and the use of producer gas for internal combustion engines and solar and wind power may complement fossil fuels and electricity in water-lifting operations.

C. MAJOR ENERGY POLICY CONCERNS

Policies governing energy resources development and management are closely related to the national economic and social development policies. Being recognized as a critical input into the development process, adequate, affordable and reliable supply of energy has always been the policy concern of the governments. Although since the mid-1980s the international price of oil remained low and stable, other factors, including the sustainability and environmental pollution concerns of major commercial sources of energy, have made the choice of fuel an even more difficult policy issue. The provision of adequate energy supplies to rural areas remains a major issue in most countries in the region. Another important policy issue that is also complex and sensitive is the domestic energy pricing policy. Particularly when the energy sector is going through a significant restructuring phase, from a largely government monopoly public sector to a more competitive private sector, the pricing policy is becoming ever more critical. For many developing economies, where the social and political objectives often do not allow the full cost (including environmental cost) of energy to be reflected, subsidies cannot be eliminated totally. Although the recent development in private sector participation in energy supply industry is seen as a welcome relief to the financing concern of some countries, it may take quite some time for others to see a greater private sector role in mobilizing necessary funds for energy projects. As noted above, environmental concern is one of the criteria that also affect the fuel policy as well as the siting problem. All these factors are having a combined effect on energy infrastructure policies and issues.

Major energy issues

In line with the above policy concerns, how to meet energy demand growth in the region, particularly in developing economies, remains at the core of the energy issues. The issue is therefore that of the sustainable development and management of energy resources with minimum adverse impact on the environment. Although the per capita energy consumption in developing economies of the region is very low, which indicates that more energy needs to be used to fuel the economic growth, in many cases energy is used inefficiently for various reasons. There is a huge potential for energy efficiency improvements, through better use of production and end-use equipment and appliances. By applying the concept of demand-side management in energy, including electrical energy, at the consumer end, a part of the demand can be met with little or no investment. Although this will not be a substitute for development, it may help defer some capacity addition for a later date. Financing energy infrastructure, along with the associated pricing issue, is another, but related, major issue. All these issues will continue to affect energy policy now and in the foreseeable future.

D. RESULTS OF THE ENERGY POLICY SURVEY

In response to a request by the secretariat, several countries or areas provided their input into the secretariat survey carried out in the first half of 1996. Most of the inputs highlighted their national policies and issues in the energy sector. Some of the salient policies and issues of common interest are summarized in the following paragraphs.

1. Energy policies and issues

The main objective of energy policy in most countries was to ensure adequate, reliable and affordable energy supply to stimulate economic growth and a decent life-style. From the submissions, it is quite clear that almost all countries have an energy policy that takes into account sustainable development as a key characteristic. Regarding the fuel policy, each country is giving high priority to the development of its domestic energy resources, such as hydro, coal, oil and natural gas, with sound environmental and social safeguards. In some of the reporting countries (Myanmar, Nepal, Tajikistan), hydropower has been highlighted as a vital but yet under-exploited resource. Resource-poor countries, such as Thailand, have embarked on meeting some of their energy needs from resource-rich neighbouring countries (Lao People's Democratic Republic, Myanmar) through subregional cooperation. In determining the fuel policy, issues of supply security, minimization of dependency on imported fuels, self-reliance, and the development of renewable energy resources have been considered. In some countries (Myanmar, Thailand) emphasis has been placed on electrification for economic development. Inter-fuel substitution (gas or LNG for oil) has been given priority in some countries (Philippines, Thailand). Efficient use of energy, in both supply and end-use, has been highlighted as a major policy objective in some of the countries. While most countries have a policy in place towards energy efficiency, the Central Asian republics are gradually introducing energy conservation measures as a part of their reform policy.

Among the major policy issues, pricing policy has been cited by many countries as important. The reasons given include encouraging efficient use of energy, introducing competitive neutrality, and encouraging private sector participation. Most have argued for an efficient energy pricing policy to have a cost-plus tariff. Some have suggested price decontrol so that the price is driven by the market. Market reform is in progress in Australia to increase the competition in and efficiency of energy infrastructure and industry. It has been noted that in Australia, the inefficiency cost of the electricity sector alone is estimated at around $A2.3 billion a year. It is apparent from the survey that subsidies and cross-subsidies (from one system to the other or among customer groups) are still practised in many countries. Energy policy in most countries calls for the removal of subsidies. The integration of environmental concerns has been well recognized in the energy policy and planning of countries of the region.

With regard to privatization policy, it appears that all countries have some sort of policy encouraging private sector investment. Most countries have either promulgated or modified electricity acts or regulations to make way for private sector participation.

For the Pacific island countries, the energy policy emphasis has been on building the national capability to monitor the supply and pricing of petroleum products and negotiation skill in competitive and transparent supply contracts with petroleum companies. Some renewable energy technologies (wood stoves, coconut oil as motor oil, biogas, solar PV, solar hot water and hydropower) have been tried through demonstration projects, with some success in hydropower and solar. Lack of institutional capacity to plan, implement, manage and maintain was blamed for not being successful in other technologies. Therefore, human resources development has been given high priority in energy sector assistance. In the electricity sector, the objective has been to improve the technical and financial performance of utilities.

2. Energy demand trends

Except for Australia (a developed member country of ESCAP) and the Central Asian republics (economies in transition), energy demand in general has been forecast to grow at a high rate of 5 to 7 per cent beyond the year 2000 (2025 for the Philippines, 2006 for Thailand). This contrasts with the projected declining growth rate of 1.7 per cent for Australia to the year 2009/10 from 2.3 per cent in 1993/94 over 1992/93. The former growth rates compare well with the secretariat's projection for the region given in the present report.

E. ENVIRONMENTAL AND SOCIAL IMPACTS OF ENERGY

During the following era, the United Nations Conference on Environment and Development, an important achievement has been a greater awareness of environmental problems in the region. While this is certainly a positive development, some related implications need to be looked at closely so that energy development and environment are not seen as adversaries. Rather, these two aspects are to be integrated so as to find a way towards sustainable energy development. Unfortunately, in many countries environmental concern has become an issue which often divides the proponents and opponents of development projects, including power plants, transmission and distribution facilities of electricity, gas and oil pipelines. Sometimes projects are being shelved because the goals and technical and/or legal requirements of the owner or developer of projects, by both public and private enterprises, are not well understood by the intervenor groups. At the same time, project developers are not accustomed to drawing on the experience in these groups to solve problems towards the realization of common goals and interests. Clearly both groups need to acquire the skills that would allow them to develop strategies towards achieving common goals. Therefore, to address this issue it is essential to engage both groups in a dialogue. The Commission, at its fifty-third session, held in April 1997, supported the participatory approach in resolving the issues with the active involvement of all stake-holders in the project design and implementation.

1. Environmental impacts of increasing coal use

One of the concerns in the area of the environment has been the adverse affects of fossil fuel use in meeting the phenomenal energy demand growth. In this respect, the environmental implications of coal use, particularly in power generation, need to be carefully assessed so that adequate measures can be taken to minimize its impact. Fortunately, clean-coal technology is available to mitigate most of the pollutants, such as oxides of sulphur and nitrogen, particulates. Innovative ways are being evolved to use waste generated from the use of coal for useful purposes. However, there is a cost that has to be incurred to reduce the pollution level to a desirable limit. An environmental standard is therefore a prerequisite for the implementation of the measures. Similarly, the costs involved should be internalized in the pricing or tariff policy. The only problem that still cannot be addressed economically with the present technology is CO_2 emissions. One way is to improve the efficiency of fuel use per unit output.

2. Social impacts of energy projects

Although the need for comprehensive environmental assessments is now widely accepted in the region, thorough social impacts assessments of new projects are not always adequately addressed in pre-development regulatory reviews. Even where substantial experience with such assessments exists, the specific targeting of impacts on low-income groups (who commonly bear a disproportionate share of the social and environmental costs) is a new and largely unexplored idea.

The socio-economic and environmental costs of energy project development are often disproportionately borne by groups which receive little direct benefit from the development itself. Commonly, environmental and social costs are imposed on poor rural residents who must relocate and often lose their traditional livelihood. In so far as major hydroelectric projects inundate large land areas, the wildlife habitat, fragile ecosystems and riverine fisheries may be destroyed or permanently damaged. Rural people often depend on these resources to maintain their subsistence lifestyle.

II. INFRASTRUCTURE DEVELOPMENT STATUS, ISSUES AND OPTIONS IN SOUTH ASIA*

INTRODUCTION

1. Scope

Many of the developing Asian countries are transiting to higher levels of economic growth in the wake of liberalization and market-oriented policies and hold promise of sustained growth in the foreseeable future, necessitating requisite energy infrastructure development. However, lack of a coherent and integrated national energy infrastructure policy in the developing countries has made the realization of optimal energy efficiency extremely difficult. Reorientation of economic policies in the era of globalization and a competitive framework demand that energy infrastructure be strengthened, and made more dependable and consumer-oriented. There has been a shift to conventional energy sources particularly because of easy availability, fuel efficiency and convenience and lesser dependence on hydro, coal and non-conventional sources. The developing South Asian economies are increasingly dependent on large crude oil imports. China is likely to emerge as an importer by the turn of the century, and oil deposits in Indonesia and Malaysia are depleting even though they will have large surpluses of natural gas. Adequate gas supplies suffer from lack of downstream infrastructure and there is need to supplement the domestic supplies in Bangladesh, India and Pakistan through building pipelines from Myanmar and Bangladesh to India and from the Islamic Republic of Iran, Kazakhstan and the Gulf to Pakistan and India. Thermal and gas-based generating plants with a reasonably short gestation period are needed to improve energy infrastructure in the short term through better maintenance, retrofitting, modernization and preventive measures, proper spares and inventory control. Efficient energy infrastructure management holds the key to sustained agro-industrial growth in many of the developing countries, which suffer from heavy transmission and distribution losses, sub-optimal pricing and are facing severe financial constraints, as illustrated by the experience of India and other SAARC countries.

The purpose of the paper is to highlight energy infrastructure development – status, issues and options, current situation and emerging trends, supply and demand gaps, fuel and environmental policies, subregional cooperation, policy options and the governments' role – in the Asian developing countries.

2. Overview: Current situation and evolving trends in energy infrastructure development (status, policies and issues) in developing countries

Developing countries in the South Asian region are currently facing very acute energy infrastructure constraints. The gap between the demand and the supply of power is ever widening, leading to a slowdown in agro-industrial growth and exports with frequent brown-outs, load shedding and voltage fluctuation. In addition, there is considerable suppressed (or pent-up) demand, with long waiting lists extending over several years. Energy infrastructure in the developing countries faces acute problems of operational efficiency and management, heavy transmission and distribution losses, ecology concerns, financial resource scarcity owing to sub-optimal pricing and absence of an integrated energy policy framework. A large sector of the population, (over 70-75 per cent) live in rural areas in Bangladesh, Cambodia, India, Lao People's Democratic Republic, Myanmar, Nepal, Pakistan, Sri Lanka, and Thailand and continue to be largely dependent on biomass-based fuels, and large regions suffer from the scarcity of traditional fuels owing to deforestation. Rural areas in Bangladesh, India, Nepal and Pakistan account for 40 per cent or more of total energy use from traditional sources: fuelwood, biomass, biogas, solar and wind sources of rural energy.

Restructuring and professionalization of electric power utilities, state-run oil and gas corporations etc. in the South Asian region are urgently needed, and have to be carried out in a time-bound schedule to reduce the time and cost overruns. The creation of regulatory commissions at centre, state and provincial levels in the region, to set the tariffs for different segments of end-users – agriculture, industrial, transport and domestic – has become inescapable, and

* P.N. Agarwala, Consultant to the Meeting.

must be manned by professionals, to improve maintenance, increase efficiency, reduce losses, and to bring down the subsidies on power and cross-subsidization of kerosene and diesel.

The vision of the closing years of this century and the twenty-first century has to take into account this emerging scenario, but also to evaluate the choices that exist at present in the developing countries and the quantifiable benefits for the future, directly impinging on their transformation to more developed economies. The current energy scenario in the region is well below the level of energy efficiency attained in several parts of the world. Sustainable agro-industrial growth depends on an adequate and dependable supply of power at cost-competitive prices, in a fiercely competitive international framework. Energy conservation and operational efficiency improvements have not taken off for lack of implementation, as the experience of India illustrates. Prices charged to consumers are often in conflict with the pricing objectives of average costs, and there are no set norms of energy efficiency pertaining to pricing decisions. In the absence of regulatory bodies for energy pricing, the authorities are not able to take rational decisions. For example, the bill for setting up such bodies is still to be enacted in the Indian Parliament. Pricing has to be vested in the hands of professionals functioning in a transparent manner and taking into account the environmental costs in the region.

The industrial sector in the region has become acutely conscious of the need for improved energy efficiency and conservation to meet the international competition. Demand for oil and gas (including LNG) is likely to grow fast in the developing countries, with their young and growing populations, in the short and medium terms, and will necessitate increasing crude oil and gas imports over the years.

Significant changes in the region are needed in the regulatory, regimented and administered price policy decisions to provide greater public accountability. Renewable energy can provide the basis for sustainable development on account of its inexhaustible nature and environment-friendly features in Bangladesh, China, India, Indonesia, Malaysia (Sabah and Sarawak), Myanmar, Nepal, Pakistan, Philippines and Sri Lanka in the long term.

China and Indonesia have very large coal deposits. India has geological reserves of around 202 billion tons, recoverable resources of 75 billion tons, and produces over 285 million tons annually, but 85 per cent of the coal is of low calorific value with high ash content, mostly used by power plants. Bangladesh, Bhutan, Nepal, Pakistan and Sri Lanka are largely deficient in coal. There is need to develop clean-coal technologies, and washeries, and to site power plants near pitheads in the region.

In South Asia there has been substitution of coal and oil by electricity and gas in steam locomotives, replacing diesel traction, and diesel pumps are being increasingly replaced by electricity in the industry and transport sectors. Electricity demand has been growing at 9 to 10 per cent annually in several of the developing countries. With their distinct usage advantages and convenience, fuel efficiency and environment friendliness over coal, oil and natural gas will continue to displace other fuels in the energy sector in developing Asian countries in the next decade or two.

Short- and Medium-term measures. The focus in the developing countries is to target and achieve maximum returns from existing assets in the energy sector, reducing technical losses in production, transportation and distribution of power, initiating action to reduce energy intensity, and maximizing satisfaction of energy demand. Medium- to long-term measures focus on substitution of petroleum products by coal, lignite and natural gas, as the region is heavily dependent on imported oil and gas supplies. The longer-term measures include use of renewable energy resources – biomass, biogas, solar, wind, geothermal, in which the region abounds – and hydro on a large scale. Bhutan and Nepal have very large hydro potential, besides Himachal Pradesh and the north-eastern region of India, and geothermal in the Philippines.

Following the Indian experience, a cleaner policy for setting up power plants is being evolved, calling for competitive global bidding under the new liberalized environment. Other developing countries are adopting this cause to achieve cost-competitiveness.

As the investments required in the energy infrastructure in the developing countries are expected to cost around a trillion dollars in the next 10 to 15 years, several countries in the region are looking for foreign direct investment, long-term credit from multilateral sources, joint ventures and production-sharing arrangements. The Indian experience illustrates the initiative for inviting foreign participation in deep water and frontier area exploration/programmes envisaged through joint ventures with state-run oil and gas corporations and international companies having innovative technologies and financial capabilities to meet the heavy long-term investments needed in high-risk/high-reward ventures. Bangladesh and Pakistan are also inviting multinational companies in the energy sector development.

The development of infrastructure in many of the developing countries in the region had been hitherto exclusively in the government domain, but the massive investments required and the organizational framework needed have necessitated the induction of private and foreign participation. Energy conservation can yield sizeable savings through plant modernization and revamping, technological updates, energy audits and studies and pumpset rectification schemes. Basic energy infrastructure facilities need to be fully geared in the region.

A. FUTURE OUTLOOK AND ISSUES

1. Supply-demand scenario

In the energy-starved growing economies in the region, emphasis on demand-side management is essential. Various steps are already being taken by developing countries towards DSM, namely, shifting the system load from peak to off-peak hours, including staggering of the weekly holidays and working hours of industrial and commercial establishments, staggering of the agricultural load etc. Incentives in terms of concessional tariffs for rescheduling loads have been introduced by installing time-of-the-day (TOD) metering. In some of the developing countries of the South Asian region, the development and manufacture of reliable and accurate TOD meters at competitive prices are essential for the large-scale adoption of differential tariffs. Energy conservation measures in the agro-industrial sectors through energy audits, awareness campaigns, the training of personnel, the conduct of research studies, and efforts towards the use of high-efficiency pumpsets are being introduced in the region. Strict control over in-house consumption on auxiliaries, and incentives for the use of energy conservation technologies and products are the basic measures being adopted by many of the developing countries in the region.

There are very considerable gaps in energy demand/supply in the region even at the base-level scenario – business as usual – and these are more pronounced at moderate and high rates of growth. The supply gap is bigger for hydroelectric projects in the region owing to their longer gestation period and other environmental factors. Vigorous monitoring effects at various levels are needed in the region to achieve the predetermined targets. Also contributing to adequate supply constraints in several developing countries are the delays in the commissioning of new thermal plants which are kept shut down for long periods for the completion of remaining activities after synchronization. The gap is intensified by heavy power transmission and distribution losses in the region owing to weak and inadequate subtransmission systems, large rural electrification projects in the South Asian region, improper load management, lower power factor of operations, poor quality of equipment maintenance and widespread pilferage/theft of power.

Pilferage of electricity in the South Asian region is very common in urban areas and is largely due to defective and tampered energy meters, unauthorized tapping and overloaded transmission and distribution (T and D) system. The high demand-supply gap can be partly bridged by involvement of the private sector in the T and D system, as it can provide more funds and organizational wherewithal through systems improvement, installation of capacitors, rigorous field inspections, monitoring and installation of foolproof energy meters, and efficient commercial practices.

There is considerable suppressed (or pent-up) demand, with long waiting lists of consumers for new connections and enhanced loads in many developing countries. To overcome this yawning gap, massive investments will be needed in the region to augment the generating capacities and ensure optimal utilization of existing capacities. Large investments from private and foreign investors will only come through if the utilities in developing countries become commercially and financially viable. The public sector alone may not be able to raise sufficient resources in the South Asian Association for Regional Cooperation (SAARC) region and in Cambodia, the Lao People's Democratic Republic and Myanmar. The performance of thermal power stations, as illustrated by the Indian experience, needs efficient management, the introduction of modern operational techniques, timely maintenance and adequate spares and proper inventory control, improving coal supplies with lesser ash content through washeries and the adoption of clean-coal technologies to achieve consistency of quality.

The energy requirements of the developing countries over the next 5 to 10 years will pose formidable challenges in terms of ensuring adequate energy supplies, investible resources and organizational framework. In India, there is currently a marked absence of commercial orientation in the State Electricity Boards and state-run oil and gas corporations. To narrow the supply-demand gap, priority in the developing countries must be accorded to systems improvement schemes (having quick returns) and to ongoing projects by reducing time and cost overruns. There is a need for financial restructuring and professionalization of management in the region and adopting modern techniques of benchmarking and re-engineering. The Indian experience shows that there is a 15 to 25 per cent shortfall in supply during normal and peak demand periods.

According to *World Energy Outlook*, East and South Asia, China and India will grow faster than the world average. The OECD forecast for developed countries is around 2.5 to 3 per cent annual growth, while many of the developing countries in the region have been witnessing 6 to 8 and 10 per cent growth rates in recent years. The populations in Japan and Western Europe are ageing and their growth rates declining, and their economies are nearing saturation point with greater stress on energy conservation in the wake of the two oil shocks of 1974 and 1979. The population in Canada and the United States of America is growing at modest rates owing to immigration and the prolific growth rate among certain groups. Developing countries of the region have young and growing populations in their quest to reach international standards.

The thermal efficiency of coal-based thermal plants in India is only 28 per cent, whereas the IIP guidelines stipulate 33 per cent efficiency, against the world norm of 38 per cent. The energy infrastructural restraints in developing countries are hamstringing the energy scenario and demand-supply gap under all assumptions – business-as-usual, low/moderate and high growth. The baseline scenario postulates around 5 per cent GDP growth. The low-moderate scenario visualizes around 6 per cent GDP growth rate, while the high-growth scenario foresees a 7 to 8 per cent annual GDP growth rate. A serious problem with utilities in many of the developing countries is the lack of professional work, team spirit, and political and bureaucratic interference. The reorientation of economic policies in the region necessitates infrastructure being made more reliable and cost-competitive in the globalized marketplace.

The degree of subregional cooperation and environmental policies in the region is becoming increasingly manifest with the agreements concluded between Bangladesh, Bhutan, India and Nepal for enhanced economic cooperation and recently (May 1997), at the SAARC summit at Male, with India, Pakistan and Sri Lanka, resolving to usher in a free trade area in South Asia by 2001. India has also become a dialogue partner with ASEAN and is seeking entry into APEC; it has also recently helped foster Regional Cooperation in the Indian Ocean Rim. Trade exchanges and relations with China are improving.

2. Current and emerging issues

Emerging trends in energy consumption reflect energy demand rising to the extent that it is constrained by supply shortages. The Indian experience illustrates that the industrial sector accounts for 60 per cent of commercial energy use, and the balance is accounted for by the agriculture, transport and domestic sectors.

Supply of electricity to the agriculture sector in the developing countries of the region entails high transmission and distribution losses, leading to higher generation requirements for each unit usefully consumed. The transport sector in the region has increasingly turned to diesel fuel in the South Asian region.

The power industry in the region has been unable to fulfil the primary obligation of ensuring adequate power supply, and the quality has also been poor and inconsistent. Hydro development in the region has lagged. The experience of India testifies that the hydro sector currently accounts for less than 25 per cent, whereas its share was over 50 to 60 per cent in the 1950s and 1960s. The enormous hydro potential of Bhutan, Nepal, Himachal Pradesh and north-east India is still to be tapped, and could also meet part of the needs of Bangladesh.

In the coming years the use of commercial sources of energy, coal, oil, natural gas and hydropower and nuclear energy are likely to increase considerably in the South Asian region. In the baseline alternative, coal production in India will increase by 5 to 6 per cent, 6 to 6.5 per cent in the low/moderate scenario and 7 per cent and above with the high-growth alternative; oil consumption will grow at 6.5 to 7 per cent in the baseline alternative, 7 to 7.5 per cent in the moderate-growth alternative, and 8 per cent and above in the high-growth rate alternative; gas consumption will grow at 7.5 to 8 per cent in the baseline alternative, 8 to 8.5 per cent in the moderate-growth alternative and 9 per cent or more in the high-growth alternative.

Nuclear power in the baseline alternative is to grow at around 2.5 per cent, rising to 3 per cent in the moderate-growth scenario and 3.5 to 4 per cent in the high-growth scenario. Non-conventional sources in the baseline alternative are likely to grow at 2.5 per cent, rising to 3.5 per cent in the moderate-growth alternative and 4.5 per cent in the high-growth alternative.

Currently, hydrocarbons contribute over 60 per cent of the global commercial energy requirements and this scenario is likely to continue in the twenty-first century. The rapid economic growth globally is manifested to a great extent in the Asian and Pacific region because of the fast economic growth taking place in many of the developing countries – China, India, Indonesia, Malaysia and Thailand. About 21 per cent of the crude oil is now being imported, and this is likely to go up to 30 per cent by 2010. The Asian and Pacific region consumes about 25 per cent of the world's primary energy requirement and is not self-sufficient in hydrocarbon requirements. The region is likely to exhibit, on the average, an annual energy demand growth rate of 3.7 per cent to 2010. Estimated proven reserves for oil and gas in Asia and the Australasian region in 1995 were 6.1 billion tons of oil and 328.6 tcf gas respectively. China will continue to contribute 40 per cent of the region's production of 150 MMTO annually, with production stabilizing by 2000. Indonesia and Malaysia will witness a steady annual fall in production over the next 15 years and may become net importers of oil by 2003, but with very large reserves of natural gas remaining.

The long-term demand forecast beyond 2001-2002 and 2011-2012 in the region is only an indicative forecast, which would facilitate the identification of resources of power for advance planning.

The lack of adequate infrastructure under the baseline scenario of business-as-usual will slow the agro-industrial growth of the developing countries considerably. The case of India illustrates that industrial production in 1997 has decelerated significantly and export growth has also plummeted. In the medium and high-growth scenario, lack of infrastructure will perceptibly hamstring the sustained growth prospects of the developing countries.

Higher energy demand growth than capacity will retard the economic development in the developing countries. There is very considerable suppressed and pent-up demand in the region in various sectors – industry, transport, commercial, agriculture and domestic – with the rapid urbanization and growth of 13 megacities in Asia and the Pacific. The base case does not fully reflect the potential demand and the medium- and long-term advance planning has to reckon with the pent-up demand projections of growing populations.

3. Fuel policy

Strategic advance planning and resource mobilization are required in developing countries, together with integrated energy policies. Increased private and foreign participation, transnational investment, restructuring of the existing power sector, redrawing of the administrative framework, deregulation and a regulatory framework are required in the region to formulate a fuel policy to meet future requirements.

The role of traditional fuels in the energy mix in the region is decreasing and is being increasingly replaced by more efficient commercial fuels. The developing countries can develop a large number of mini and micro hydel power plants which would be ideal peak load stations, with no threats to the biosphere, in addition to exploiting the large hydro potential and achieving a balanced thermal-hydro mix in the South Asian region. As the costs of generation, as well as operation and maintenance, are much lower in the case of hydro projects, and considering their inherent ability for quick starting and stopping, thereby being most suited to meeting the peak demand and enhancing system reliability, the pace of hydropower development in the region needs to be accelerated in the medium- and long-term perspective.

Investment levels of between 4 and 4.5 per cent of GDP of developing countries are required to meet the energy demand gap and the effective implementation of the fuel policy for the medium and high-growth alternatives. Resource constraints have traditionally provided the impetus for technological changes in the region, resulting in generating incomes which fuel higher levels of consumption, as reflected in the Indian experience. The overall requirements of funds for the ninth Plan (1997-2002) for India are given in annex I to the present paper.

4. Research and development

There is need to harness supercritical and ultra-supercritical pulverized boiler technology, pressurized fluidized bed combustion and integrated gasification combined technologies in the developing countries to achieve cost-competitiveness and optimal resource utilization. Smaller power plants could be set-up in 18-24 months, as mega power projects of 500 to 1,000 MW have a longer gestation period, with savings in pre-operative expenses. Smaller plans can be sited close to load centres to avoid transmission/ distribution losses.

5. Environmental policy

The environment management regime in the region brings the entire gamut of commercial energy production within the purview of obligatory remedial standards. Environmental costs are not currently internalized in most of the developing countries. Energy production and consumption lead to certain emissions from the production and burning of fuels that have a greenhouse effect. There is need for natural resources accounting which can help identify optimal depletion paths by estimating depleting premia associated with energy forms/technologies. Environment costs would also have to be built into hydro project costs. There is need for greater stress on renewable decentralized energy forms and the use of recycling of waste as the developing countries face severe ecological imbalances and demographic pressure. The populations in the region are young and growing. The environmental impacts associated with natural gas, some well-chosen hydro and nuclear power are smaller than those associated with coal and oil. The import of electricity by Bangladesh and India from Bhutan and Nepal could make a substantial contribution to lowering the growth of greenhouse gas emission and air pollution.

B. POLICY OPTIONS AVAILABLE TO ADDRESS THE ABOVE ISSUES

In the baseline alternative (business-as-usual), the policy options are essentially of a short-term nature. Integrated energy infrastructure policies need to be clearly formulated and implemented by developing countries to achieve optimal utilization of the existing capacities in the region. The setting up of a regulatory mechanism at central, state and provincial levels by developing countries to lay down tariffs on a rational basis for different segments of users and for the professionalization and toning up of the utilities and state-run coal, oil and gas corporations, brooks absolutely no delay. This will help the renovation and modernization of power plants and help raise the production of commercial fuels in the region. There is an urgent need to induct private sector participation in transmission and distribution to bring down the heavy losses and pilferage so widespread in the South Asian region, as exemplified by the Indian experience. Captive power plants need to be encouraged through incentives.

In the low-growth and medium-term alternatives, the creation of new capacities will entail heavy investments and resource mobilization in the region. Private investments will be required in increasing amounts as public finances in many of the developing countries are already overstretched to the limits. Private sector participation can help achieve optimal operational efficiency and induct new technologies for realizing cost-competitiveness and avoidance of time and cost overruns and achieve demand-supply equilibrium.

A longer-term alternative of sustained high growth in the developing countries in the twenty-first century will call for very massive foreign and domestic investments in energy infrastructure, renewable energy resources, improved technologies, conservation and eco-friendly use with stress on the hydro, non-conventional energy, coal and gas sectors as the region's hydrocarbon resources are not sufficient to sustain the demand, and are likely to plateau and show depletion levels in China, India, Indonesia, Malaysia and Pakistan over the next 7 to 10 years.

C. THE PRIVATE SECTOR AS A PARTNER: PROS AND CONS

In many of the developing countries, the power, oil and gas sectors have been thrown open to private and foreign participation in the wake of the liberalization policies, paucity of adequate resources with the utilities and public sector corporations to bridge the widening gap between the rapidly growing energy demand and supply in the region. A two-part tariff system for power projects set-up by independent power producers to cover the fixed costs and variable energy costs in pricing is being formulated and implemented by several developing countries.

In the developing countries there is an imperative need for guidelines for a detailed policy framework for retrofitting and renovation/ modernization to be clearly laid down and implemented.

Captive co-generation plants are being encouraged in the region. Distribution infrastructure – cross-country pipelines, ports, terminals, tankages and the build-up of strategic reserves will need to be operationalized in the medium-term, and additional refining capacities built, by the expansion or setting up of new grass-roots refineries in the developing countries to meet the demands.

The optimal development of non-conventional energy resources – wind, solar, geothermal, mini hydel, biogas – will need to be accelerated in the region for long-term perspectives and sustainable growth. The region has sizeable resources to be tapped.

As most of the utilities in many of the developing countries are not financially viable, private investment is not flowing at the required level. The necessary preparations had not been made for according the required clearances for various purchase price agreements and environmental aspects, and the protracted negotiations and procedures leading to long delays need to be avoided.

There is an imperative need for open tenders, competitive bidding, and transparency in awarding contracts and in the conduct of negotiations. Power generation could be leased by the utilities in the region to the private sector to improve maintenance, renovation and repowering. There is need to encourage more players and stiff competition to keep costs down. The administrative set-up of the utilities and public sector corporations in the energy sector needs to be put in the hands of technocrats and professional managers rather than bureaucrats, who are steeped in archaic rules and are procedure-oriented, and to depoliticize the functioning of the energy infrastructure sector in the region, as borne out by the experience of the South Asian region.

D. THE ROLE OF GOVERNMENT: CHANGING FROM PLANNER TO REGULATOR

The experience of the past three to four decades in the South Asian region clearly brings out the governments' need to increasingly shed their role of planner in the energy infrastructure area. Government rules and procedures lack proper time-bound implementation schedules, leading to massive cost and time overruns. The role of governmental in the region has tended to breed inefficiency and inordinate delays in operations owing to lack of accountability, performance audit and commitment to high professional standards of excellence.

Now that the economies in many of the developing countries have to compete in the fiercely competitive international framework, the energy costs have to be kept down to competitive levels, for optimal utilization of physical, human and financial resources.

The present scenario of virtual power famine in large parts of the region clearly illustrates that the governments of the developing countries have to move away from their earlier role of planner to a regulatory mechanism to protect consumer interests.

There is need to develop professional competence through predetermined target-setting, close monitoring, performance appraisal, evaluation, performance audit, benchmarking, re-engineering and the induction of technocrats in the government sector for optimal utilization of available resources for the common good in the region.

1. Regional cooperation

International cooperation and the pooling of resources can be effectively utilized for developing the technologies and systems for achieving optimal growth in the developing countries.

The SAARC countries should develop integrated power generation and distribution plans to achieve greater generation capacities, efficiency and better voltage profiles, in the wake of the recent Male Summit declaration. Bangladesh, Bhutan, India, Nepal and Pakistan could go in for power trading to achieve better peak demand and load management. They could also plan intercountry projects to maximize utilization of natural resources, topography and economies of scale. India has expressed interest in buying 3,000 MW of electricity from Pakistan and also supplies from Bhutan and Nepal.

There have been institutional bottlenecks between India and Pakistan in the past which need to be overcome to foster the spirit of subregional cooperation and also in the Asian and Pacific region. The recent SAARC meeting at Male holds out promise of increased techno-economic cooperation to usher in a free trade area in the region in the next five years.

2. Conclusions and recommendations

Upgraded power capacities are needed to augment supplies in the near term to meet the demand-supply gap in many of the developing countries. Environmental hurdles have to be surmounted. Time-bound clearances, and streamlining of bureaucratic rules and procedures are basic if the region's economies are to realize the growth targets.

To augment energy production, infrastructure and refining capacities in the developing countries, there is an imperative need to encourage large private and foreign investments. More players are needed to spur competition as currently there are few players in the region and these comprise chiefly state-run corporations in the energy sector.

Many of the utilities in developing countries are financially non-viable and their restructuring is essential. With deregulation, there will be more players – domestic and foreign – in transmission and distribution, and generation will increase as there are customers who are ready to pay more for quality supplies.

The setting up of a regulatory framework in developing countries is necessary for retrofitting, renovation, modernization, overseeing and monitoring, with three sets of players: generators, transmitters and distributors. Norms have to be laid down and generators have to have environmental norms. There is need for more build, operate and transfer projects in the energy infrastructure sectors. At present, there is no audit for non-performance and more public accountability is required in the region to achieve high standards of efficiency and optimal utilization of resources.

There is need for transparency and competitive bidding to keep costs to the lowest levels in a globalized competitive framework. Contracts to be awarded must adhere to close scrutiny and accountability. More players and joint ventures and collaboration are needed in both upstream and downstream oil/gas operations, and the organizations engaged in these sectors have to have greater customer orientation. Regulation should be sector-specific to ensure that customers are not fleeced and receive a fair deal.

The government's role in the developing countries has to be more regulatory, to ensure public interest and common good, and not that of a planner or promoter as in the past. Governments must ensure that high ethical standards are followed. The same rules should apply to government and the private sector, and a level playing field is required for all players. Phasing out and abolishing the administered pricing system is vitally needed. The Indian experience is illustrative of the massive oil pool deficit of nearly $5 billion dollars as kerosene, diesel and LPG are heavily cross-subsidized. Subsidies in the transport and domestic/agriculture sectors need to be pruned for sustainable development in the region and to achieve cost-competitiveness.

There is need for more technological thrust in the non-conventional energy sectors and more operational decentralization is required in the region. There is an urgent need to review policy hurdles in many of the developing countries.

There is no threat of exploitation by multinationals, and national interests can be protected by governments in the region by cutting down time and cost overruns and streamlining rules, procedures and clearances. Multinationals have evolved a voluntary code of conduct under OECD auspices. There has been no major nationalization of multinationals in developing countries following the oil shocks of 1974 and 1979. Many of the developing and erstwhile centrally planned economies are wooing multinationals for their investments, technological updating, management and organizational systems and their worldwide marketing networks. Multinationals have developed a long-term perspective and are trying to identify increasingly with host country sensibilities.

In the developing countries, there is need for professionalized management practices with more accountability, to ensure adoption of technological advances for improving existing and future assets in the energy infrastructure sectors, and raising productivity; and building up a work culture and team spirit. Improved energy efficiency of plants and installations together with conservation and demand-side management can help to realize the near-, medium- and long-term development plans on a sustainable basis in the region.

ANNEXES

I. FUNDS FOR RURAL ELECTRIFICATION (IN INDIA)

	Million rupees
Village electrification (30,000 villages)	18 500
Pumpsets energization	60 000
Integrated system improvement	15 000
Intensive load development	31 300
Kutir Jyoti (37 lakh households)	3 700
Electrification of Harijan Bastis/Hamlets (1 lakh)	20 000
Small power generation	5 000
Rural electric cooperatives	154 000
Subtotal	307 500
Special programmes	50 000
100 per cent electrified villages	
Technology upgrading	
System improvement projects	
R and D	
Renewable and non-conventional energy sources	
Training	
Total	**357 500**

II. OVERALL REQUIREMENT OF FUNDS THE NINTH PLAN (INDIA) (1997-2001)

	Million rupees
Generation (including nuclear projects)	1 172 050
Transmission and distribution	1 139 700
Renovation and modernization scheme	100 450
Manpower planning and training	1 500
Research and development	20 000
Rural electrification	204 000
Energy conservation	3 970
Total power sector	**2 641 670**

III. ENVIRONMENTAL AND SOCIAL IMPLICATIONS OF ELECTRIC POWER SECTOR RESTRUCTURING*

Programme statement

BACKGROUND

Over the past several years, pressure has been increasing throughout the world for fundamental changes to the structure of the electric power sector. Once regarded as a natural monopoly and critical "national security" sector best suited for state ownership, the power sector has been undergoing a transformation under which the new watchwords have become privatization, deregulation and unbundling.

Chile and the United Kingdom of Great Britain and Northern Ireland are perhaps the two countries which have undergone the furthest, breaking up state-owned vertically integrated monopolies, unbundling generation, transmission and distribution services into separate companies, and introducing competition between generating companies.

In the United States of America, utilities have long been privately owned but vertically integrated regional monopolies nonetheless. The United States began its power sector restructuring process not by breaking up its utilities, but rather by mandating that utilities purchase power from non-utility generators at their avoided costs through the Public Utility Regulatory Policies Act of 1978. The United States restructuring process was pushed ahead significantly in 1994 when the State of California began hearings into a complete regulatory overhaul of the State's electricity system, with the prospect of introducing full retail-level competition by 2002.

These trends towards privatization and increased competition are not confined merely to industrialized countries. Spurred on by the World Bank and the International Monetary Fund, many developing countries are in the process of fundamental economic reform entailing significantly increased private sector participation in previously state-run facilities, including electric power.

Restructuring of the electric power sector can take different forms, varying in terms of both degree of private sector participation and of unbundling (splitting vertically integrated monopolies into separate generation, transmission, and distribution entities). In some countries, the government-owned monopoly structure has been fundamentally maintained, but private independent power producers (IPPs) have been invited to construct new power plants and sell their power to the state monopoly. This has been the basic approach of many South-East Asian countries, including Malaysia, the Philippines and Thailand. Other countries have taken a more radical approach, choosing to dismantle the state monopoly and move toward complete privatization and unbundling. Argentina and Chile may be the primary exponents of this model.

A. RATIONALE

Regardless of the model used, the fundamental objective of electric power sector restructuring has been the same in all countries: to improve the efficiency of electricity provision, utility financial performance, and service. The potential gains through such restructuring can be enormous, particularly in countries where, through subsidies from taxpayers, state utilities currently sell power at below-market rates, thereby distorting the economy, encouraging overconsumption, and depleting state coffers.

However, power sector reform can also have other unintended consequences not always envisioned by the promoters of reform. Though these side effects can be both positive and negative, there is a danger that the momentum for restructuring, often ideologically driven by a "free-market" agenda, may in particular overlook some of the reform's negative side effects. Environmental considerations and social equity issues are two areas in which side effects of power sector reform may be particularly significant.

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B. PROGRAMME SCOPE

As part of its work programme for 1996-1997, the UNEP Collaborating Centre for Energy and Environment and the Center for Energy-Environment Research and Development (CEERD) are undertaking a programme to study the environmental and social implications (both positive and negative) of electric power sector restructuring and to develop methods to improve the outcomes, particularly in developing countries. The programme will consist of the following broad tasks:

- Review of available experiences and approaches to power sector restructuring
- Assessment of environmental and social implications of restructuring
- Analysis of regulatory structures and incentive mechanisms to enhance environmental and social outcomes
- Implementation of specific country studies carried out in collaboration with countries in varying stages of restructuring
- Dissemination of results and lessons of country studies to enhance regional information base and cooperation

Some of the specific issues to be considered are discussed below.

Environmental considerations

- One of the primary issues driving power sector reform is that of electricity pricing. In developed countries, the common argument is that electricity is overpriced owing to existing utility and regulatory inefficiencies, thus stifling economic growth. In this case, reform is meant to lower electricity prices; but lower prices inevitably encourage increased consumption, thus increasing environmental damage. On the other hand, in developing countries electricity is often subsidized and thus underpriced; and one of the main goals of reform is to raise prices to world market rates. In this case, reform should help reduce consumption and thereby reduce environmental impacts.
- The development of modern renewable energy technologies has been largely induced by regulatory mandates to utilities to purchase power from renewable energy suppliers. Though often flawed and controversial, these mandates have served to significantly enhance technology development and reduce the technologies' costs. However, in spite of great strides, most renewable energy technologies are not yet cost-competitive against conventional fossil fuel-based generation. As regulatory mandate gives way to open price-based competition, there is danger that further development of not-yet-competitive renewable technologies may be hampered.
- The decision to build certain types of power plants (coal, natural gas, hydro, nuclear etc.) is usually based on a variety of factors. Under the traditional utility structure, utilities and regulators have often considered, in addition to project economics, things such as fuel diversity, environmental impact, indigenous fuel availability, technology development objectives, and political objectives. This has led to both positive well-balanced results and negative politically dominated results. Under a privatized competitive structure, the potential for political manipulation should be lessened, but balanced long-term perspectives may suffer as well. For example, with current low prices for natural gas, an overdependence on natural gas could emerge based on short-term profit opportunities; and development of higher capital cost alternatives, including hydro, renewables and nuclear, could be hampered.
- Independent power producers relying on international capital markets for financing tend to be highly risk-averse, especially in developing countries. With perceived high risks stemming from political instability or domestic fiscal/monetary instability, IPPs strive to minimize technical risks to the greatest extent possible, often by using well-established proven technologies rather than newer cleaner technologies. Incentive structures may be required to reduce technological risk-aversion in developing country privatized power markets.

- In the last 10 years in developed countries, utilities have played a major role in promoting energy efficiency. In the United States, this has been largely influenced by regulatory changes making investments in conservation more attractive than investments in generation. Current power sector restructuring efforts have caused many utilities to lose interest in energy efficiency, however, as they move back towards being straight commodity providers of electricity at the lowest price possible. Third-party energy service companies are emerging to fill the energy efficiency role, but the sheer size limitations of such companies make, it unclear whether they can implement energy savings on the scale of the utilities. Maintaining momentum for improvements in energy efficiency will be a key challenge in the restructured electricity sector.

- IPP contracts such as BOT arrangements involve IPPs building and operating power plants for a fixed period of time, after which the plants are transferred to the utility. In such cases, the IPP involvement is time-limited, possibly causing IPPs to have less of a long-term stake in managing the environmental impacts of their activities compared with domestic utilities.

Social considerations

- Electricity is often subsidized for residential customers, particularly in developing countries. In countries where per capita GDP may be in the range of a few hundred to a few thousand dollars per year, electricity charged at world market rates may be unaffordable for a large percentage of the population. As electricity provides a broad range of useful social services, making it unaffordable would have wide-ranging social ramifications.

- In connection with the above point, if electricity become unaffordable for many residential customers, they will be likely to switch to other energy sources to meet their needs. Depending on what residences normally use electricity for, rationing electricity use could increase the use of traditional fuels such as wood or charcoal. This could lead to increased environmental problems such as urban air pollution or deforestation.

- Many developing countries are engaged in rural electrification programmes designed to bring electricity to areas where it is not currently available. The implications of power sector restructuring for rural electrification are not clear. As many of these rural programmes do not earn a sufficient return to be commercially viable, privatization and competition may serve to eliminate much rural electrification. On the other hand, elimination of subsidies and forcing rural customers to pay full market rates may make some electrification programmes more viable or may help market adoption of renewables by highlighting the advantages of stand-alone wind or photovoltaic systems in remote areas.

- If rural electrification programmes are reduced or eliminated, this would severely curtail the economic and social development of rural areas. One possible consequence of this may be increased migration of rural populations to urban areas, further exacerbating the problems of urban overcrowding and attendant social ills from which many cities already suffer.

C. ACTIVITIES

In the light of the considerations outlined above, a systematic programme is necessary to analyse the issues and develop means of improving the environmental and social outcomes of electric power sector restructuring. As "developing countries" encompass a wide range of circumstances and modes of power sector reform, the programme will emphasize detailed case studies of certain selected countries with different economic development levels and electricity sector structures. Through these studies, to be done in active collaboration with in-country institutions, the goal is both to assist the specific countries in their restructuring efforts and to draw broader lessons which can be applied to other countries facing similar circumstances.

Each country study will emphasize the following main steps:

1. Assess current environmental protection standards, practices and laws in the country.

2. Understand the current structure of the electric power sector and the types of reforms proposed.

3. Analyse the likely implications for the environments and for social equity as private sector participation in the provision of electricity increases.

4. Evaluate strategies to minimize the negative environmental and social impacts of power sector restructuring.

5. Assess the institutional capacity of countries to implement these strategies and identify capacity-building needs.

The alternative regulatory strategies will include not only the traditional command-and-control type mechanisms, but will also emphasize economic instruments to achieve the desired aims as cost-effectively as possible. The key will be to provide proper economic signals to all actors in the newly restructured electric power industry to link financial performance with the achievement of environmental and social goals.

ANNEXES

I. PROJECT PROPOSAL 1: ENVIRONMENTAL AND SOCIAL IMPLICATIONS OF POWER SECTOR RESTRUCTURING IN ASIA

I. PROPOSAL SUMMARY

1. Name of project proponent

Center for Energy-Environment Research and Development-Asian Institute of Technology (CEERD-AIT)

2. Type of institution

The Asian Institute of Technology (AIT) is an autonomous, non-profit, international post-graduate technological institution. CEERD-AIT is a unit under the Asian Institute of Technology which serves as a training and research support unit of the energy economics and planning field of study under the energy programme of AIT.

3. Project objective

To assess the environmental and social implications of power sector restructuring in Asia and analyse incentive mechanisms for reducing negative environmental impacts.

4. Project description

The project will consist of the following broad tasks:

1. Review experiences and approaches to power sector restructuring in the region.
2. Assess the environmental and social implications of the restructuring efforts.
3. Analyse regulatory structures and incentive mechanisms to enhance environmental and social outcomes.
4. Implement country study: case of Thailand.

The country study, on the other hand, will emphasize the following main steps:

1. Assess current environmental protection standards, practices and laws in the country.
2. Understand the current structure of the electric power sector and the types of reforms proposed.
3. Analyse the likely implications for the environment and for social equity as private sector participation in the provision of electricity increases.
4. Evaluate strategies to minimize negative environmental and social impacts of power sector restructuring.
5. Assess the institutional capacity of the country to implement these strategies and identify capacity-building needs.

5. Proposed duration of the project

One year

6. Project cost

Total cost of project US$ 352 002

7. Potential collaborating or participating organizations

UNEP Collaborating Centre for Energy and Environment (UCCEE), Roskilde, Denmark

UCCEE will provide a specialist on energy and environmental analysis with experience in assessment of environmental and social implications of sector reform programmes including the application of specific regulatory and policy instruments. The UCCEE will also contribute information and experience from power sector reform programmes in other regions.

Electricity Generating Authority of Thailand (EGAT), Nonthaburi Province, Thailand

EGAT will provide data and information required by the project, assist EPCCT-AIT in gathering information if this is not available in EGAT, and coordinate contact with private power developers in Thailand. The opinion of EGAT on the preliminary analysis and recommendations will also be sought before preparing the final report.

National Energy Policy Office (NEPO), Bangkok, Thailand

NEPO is expected to assist in collecting data and information for the project. The opinion of NEPO will be sought before preparing the final analysis and recommendations.

II. NARRATIVE DESCRIPTION OF THE PROJECT

1. Objective and scope of the project

The objective of the project is to assess the environmental and social implications of power sector restructuring in Asia and analyse incentive mechanisms for reducing negative environmental impacts.

The project will consist of the following broad tasks:

1. Review experiences and approaches to power sector restructuring in the region.
2. Assess environmental and social implications of the restructuring efforts.
3. Analyse regulatory structures and incentive mechanisms to enhance environmental and social outcomes.
4. Implement country study: case of Thailand.

As the countries in the region encompass different circumstances and modes of power sector reform, the project will emphasize a detailed case study that will be done in close collaboration with the in-country institutions. The immediate goal is to assist the specific country in its restructuring efforts and to draw broader lessons which can be applied to other countries. The country study will be the main avenue through which the objectives of the study will be achieved. The project will initially focus on Thailand.

In recent years, Thailand has been one of the fastest growing economies in the region. Its more than 8 per cent growth in real GDP in the 1990s has been matched with close to 13 per cent growth in electricity consumption. This trend is expected to continue in the future, though probably at slightly lower rate. The Government, through the Electricity Generating Authority of Thailand (EGAT), plans to add more than 2,000 MW of generating capacity annually over the next 15 years and more than 40 per cent of these capacity additions will be for private power undertaking. Recently, EGAT has raised the IPP capacity opened for first bidding to 5,800 MW from 4,200 MW. In addition, EGAT has been actively making progress in its bid to privatize utility operations. For example, it has created a subsidiary (EGCO) that is 50 per cent owned by the public to operate two of its large combined cycle power plants. Activities are also under way for the full privatization of the utility itself.

The country study will emphasize the following main steps:

1. Assess current environmental protection standards, practices and laws in the country.
2. Understand the current structure of the electric power sector and the types of reforms proposed.
3. Analyse the likely implications for the environment and for social equity as private sector participation in the provision of electricity increases.
4. Evaluate strategies to minimize the negative environmental and social impacts of power sector restructuring.
5. Assess the institutional capacity of the country to implement these strategies and identify capacity-building needs.

The first step will involve closer examination of existing pollution standards and the environmental impact assessment (EIA) process in Thailand. Pollution standards will be compared between new and existing power plants and will be summarized to include not only air emissions but also any standards relating to water and land impacts. Thailand's EIA process will be compared to existing World Bank guidelines to provide an indication of the completeness of the Thai EIA process.

The goal of this task is to obtain a general indication of the baseline conditions present in current Thai environmental regulations. These regulations will be analysed to determine whether the regulatory conditions contain any inherent biases which tend to favour one technology or fuel over another.

The first step will also assess EGAT guidelines regarding environmental considerations in the IPP contracting process. In this task, the existing EGAT guidelines will be studied in terms of how they affect decisions regarding the choice of fuel, technology, plant location, and management practice. In addition to providing further valuable information, this task should also assist EGAT power contracting decision makers in determining how effectively current practices are affecting IPP projects in the desired direction.

The second step will review the structure of the electricity sector in Thailand. This will identify the main actors in the sector and the existing government regulations. The focus of this step, however, is on the ongoing and planned reforms in the sector and the ongoing privatization of EGAT.

An understanding of the restructuring and privatization process will facilitate the accomplishment of the third step. Here the environmental and social equity issues arising from restructuring and privatization will be identified and their impact analysed.

With regards to the fourth step, two regulatory tools are usually, if not always, part of an environmental protection plan: emission standards and environmental impact assessment requirements. Indeed, they are important components. Yet there exist significant limitations in the effectiveness of these measures to optimally achieve environmental goals. For example, emission standards specify only the minimum level of pollution controls to be installed; they provide no incentive for power plant builders to go beyond the mandated minimum controls to make the plants even cleaner. Similarly, environmental impact assessments are fundamentally limited in that they provide no incentive to the developer to go beyond the minimum environmental standard specified by law. In many cases, guidelines for impact assessment are sufficiently loose that projects with significant environmental impacts are nevertheless constructed with few substantive modifications. Therefore, emission standards and environmental impact assessments, while necessary, often fail to achieve environmental protection in an efficient manner.

A third necessary tool is represented by economic incentive mechanisms which successfully align financial performance of the private power developer with societal environmental goals. Such incentives encourage developers to go beyond the minimum requirements set by the standards and environmental impact assessment and improve profitability in the process. Thus, the alternative strategies will include not only the traditional command-and-control type mechanisms, but will emphasize economic instruments to achieve desired aims as cost-effectively as possible. The key will be to provide proper economic signals to all actors in the restructured power industry to link financial performance with achievement of environmental and social goals.

The fourth step will, therefore, involve a review of economic incentive mechanisms for environmental protection which may be applicable to Thailand's IPP situation. The most appropriate mechanisms for further study will be identified through analysis of the current contracting process of EGAT and discussions with appropriate parties in Thailand.

The fourth step also includes a study of the experience of other countries to determine what approaches have been successful in obtaining cost-effective environmental protection in IPP projects in developing countries. Again, the goal will be to go beyond simply environmental impact assessment and standards, and to look for more creative solutions based on economic incentives within the contracting process.

Lastly, the economic instruments of greatest interest will be analysed to determine the impact of these mechanisms on project implementability, environmental impacts, power cost, and plant dispatch.

The goal of the fifth step is the proper application of the instruments identified under the fourth step. This can only come from a precise knowledge of their use and effects. Thus, the fifth step will involve strengthening the capacity of the institutions to use the most effective instruments. For this purpose, training seminars and workshops will be organized for the relevant institutions.

2. Project output

A project report will be developed to cover the results of the tasks outlined. The report will include:

- A summary of the experiences and approaches to power sector restructuring in Asia
- An assessment of the environmental and social implications of power sector restructuring
- A summary of existing Thai environmental regulations for power plants, pollution standards, and environmental impact assessments

- An analysis of the power sector restructuring process and its likely social and environmental implications
- An evaluation of strategies to reduce negative environmental impacts, focusing on economic incentive mechanisms

The project should benefit EGAT and Thailand in several ways. First, it will provide EGAT with options to cost-effectively reduce the environmental impacts of its planned private power projects and privatization. For Thailand as a whole, the concepts outlined here can provide a basis for both economically and environmentally sustainable development over the coming years. These concepts can easily apply to other areas of environmental protection outside the power sector.

An important goal of this project upon its completion is the dissemination of information gathered and conclusions drawn. The results of the project will of course be presented to the Government of Thailand through the management of the participating institutions. In addition, as mentioned earlier, to successfully implement the recommendations of the project, particularly in relation to adapting regulatory strategies and using economic instruments, a seminar for this purpose will be organized. The results, moreover, can also be presented in a regional workshop organized in collaboration with international organizations. Similarly, the results can be presented in other international conferences and seminars in and outside Thailand. Thus, the project should serve as the starting point for similar work in the area of environmental protection in the region.

3. Qualifications of the project proponent and proposed participants

The proposed project will be principally undertaken by the Center for Energy-Environment Research and Development of the Asian Institute of Technology (CEERD-AIT), the project proponent.

The Asian Institute of Technology (AIT) is an autonomous, non-profit, international post-graduate technological institution located in Bangkok. Its mission is to take a leadership role in the promotion of technological change and its management for sustainable development in the Asian and Pacific region through high-level education, research, and outreach activities which integrate technology, planning, and management. AIT has four schools, namely, the School of Environment, Resources, and Development (SERD); the School of Advanced Technology; the School of Civil Engineering; and the School of Management. Each school specializes in various fields of study. The Energy Programme under SERD consists of three fields of study: energy economics and planning, electric power system management, and energy technology.

The Center for Energy-Environment Research and Development is under the Energy Programme of the Asian Institute of Technology. CEERD-AIT serves two purposes: on the one hand, as a training and research support unit of the energy economics and planning field of study of the Energy Programme, and, on the other hand, as an implementing agency for research and training projects in energy-related issues in order to strengthen the capacity of national governments and energy producers in energy planning and policy formulation.

CEERD-AIT has the experience, expertise and the tools to carry out the proposed project. The activities that have been carried out by CEERD since its establishment in 1986 cover the whole spectrum of energy planning. The activities include research studies and regional and international training workshops and seminars. Recently, or in the last two years, for example, regional workshops and training seminars were organized in relation to energy-environment planning. CEERD has undertaken several sponsored studies and research projects. Since 1993, for example, it has been involved in developing an Asian version of an energy-environment model (EFOM-ENV) which will be used to study the relationships between energy systems and the environment in developing countries of the region. The team members also undertake and publish studies and research projects on their individual capacity. The team has also developed and has access to the methodological tools (energy planning-related models) for implementing its projects.

All CEERD projects have been done in close and active collaboration of many international and national organizations in and outside Asia. (The long list of all these national and international agencies can be seen in the brochure of the organization.) Its close contact with these organizations will therefore facilitate implementing the proposed project on a specific country and regionwide basis.

The original concept for the project was developed by the United Nations Environment Programme Collaborating Centre on Energy and Environment (UCCEE). UCCEE, established in 1990 and hosted by the Riso National Laboratory, Denmark, has the overall aim of promoting the incorporation of environmental considerations in energy planning worldwide, particularly in developing countries. UCCEE works catalytically, encouraging, promoting and supporting research by local research institutions, coordinating projects and disseminating information, as well as carrying out a full in-house research programme in close collaboration with other colleagues at Riso National Laboratory and internationally. UCCEE, moreover, has extensive experience in capacity-building activities.

CEERD-AIT will work closely with UCCEE on this project. UCCEE, which has committed itself to shouldering a significant portion of the funding requirements, will provide a specialist on energy and environmental analysis with experience in assessment of environmental and social implications of sector reform programmes, including the application of specific regulatory and policy instruments. UCCEE will also contribute with information and experience from power sector reform programmes in other regions.

For conducting the country study for Thailand, CEERD-AIT will rely on the close and active collaboration of the National Energy Policy Office (NEPO) and the Electricity Generating Authority of Thailand (EGAT). NEPO serves as secretariat to the National Energy Policy Council, Thailand's highest energy policy-making body, which is headed by the Prime Minister. The decisions made by the Council are based on the analysis, evaluation and recommendations of NEPO on energy issues. NEPO, for instance, coordinated with the country's government-owned electric utilities (that is, including the Metropolitan Electricity Authority and the Provincial Electricity Authority, which are in charge of distribution) in preparing the blueprint for the privatization plan of the power sector in Thailand.

EGAT, on the other hand, is the state-owned utility charged with the generation and transmission of electricity. Until recently, EGAT has monopolized the generation of electricity. Since the amendment of the EGAT Act in 1992, however, EGAT has seriously pursued privatization and opening up generation to independent power producers. EGAT solicits and directly approves private power proposals. IPP adherence to the country's environmental standards is critically factoured in EGAT's evaluation. CEERD-AIT will, in particular, work closely with the Environmental Department of EGAT, which is concerned with evaluating the environmental impacts of power plant projects.

4. Timetable of activities

A proposed timetable of activities is given in table III.1.

The project will consist of two phases. Phase I may be called the overview phase, which will accomplish the objectives of the project from a regional point of view. It will involve review of the region's experiences in power sector restructuring, particularly with regard to IPP contracting and privatization of electric utilities, identification and assessment of likely environmental and social implications of these reforms, and analysis of regulatory and economic instruments which will reduce the negative impacts of the reforms. Obviously, Phase I will involve a lot of desk research. UCCEE has indicated that it can accommodate two months of guest research work for CEERD staff at their offices in Riso National Laboratory (Denmark). This should be covered under Phase I.

The second phase of the project will be the country study. Unlike the first phase, Phase II will involve a lot of field research: primary data gathering to obtain the latest statistics and information, discussions with EGAT and NEPO officials and those of other relevant Government institutions, and inspection of one or two IPP power plant project sites. This will probably take one third of the time alloted for phase II. The same amount of time would be spent on analysing the social and environmental implications of the Thailand power sector restructuring and evaluating the most appropriate economic instruments to reduce identified negative environmental and social impacts. The remaining period will involve consolidating analysis and recommendations, discussing these with NEPO and EGAT officials, preparing the final report, and training of EGAT and NEPO staff.

Table III.1 Project 1: Timetable of activities

	Month 1	*Month 2*	*Month 3*	*Month 4*	*Month 5*	*Month 6*	*Month 7*	*Month 8*	*Month 9*	*Month 10*	*Month 11*	*Month 12*
Overview												
1. Review of Asian experiences in power sector restructuring												
2. Assessment of environmental and social implications of restructuring												
3. Analysis of regulatory and economic instruments to enhance environmental and social outcomes of restructuring Thailand Country Study												
4. Assessment of environmental regulations												
a. Review of existing environmental laws, standards, and EIA process												
b. Assessment of EGAT environmental guidelines												
5. Study of power sector structure, regulations, and reforms												
a. Review existing power sector structure and regulations												
b. Study ongoing and planned sector reforms and privatization of EGAT												
6. Analysis of environmental and social implications of reforms												
7. Evaluation of strategies to minimize negative impacts of reforms												
8. Consolidation of analysis and recommendations												
9. Preparation of draft report												
10. Presentation to EGAT and NEPO officials												
11. Writing up the final report												
12. Seminar for EGAT and NEPO staff												

II. PROJECT PROPOSAL 2: DEVELOPMENT OF A METHODOLOGY FOR THE MONETARY VALUATION OF ENVIRONMENTAL DAMAGE CAUSED BY AIR POLLUTION FROM POWER GENERATION IN DEVELOPING COUNTRIES AND ITS APPLICATION

I. SUMMARY OF THE PROJECT

1. Project proponent

Energy Planning Central Consultant Team

Energy Programme

School of Environment Resources and Development

Asian Institute of Technology, Bangkok

Type of institution:

Non-profit international post-graduate technological institution

2. Project objectives

The goals of this project are:

- To develop an analytical methodology for undertaking the monetary valuation of environmental damage of air pollution from fossil fuel power generation; the methodology will have to be applicable for the conditions of developing countries
- To apply this method to the case of power plants in Thailand
- This methodology is to be disseminated to other Asian developing countries thorough a regional workshop and publication of the results of the project

3. Project descriptions

The project will be carried out in two phases (and can be extended):

Phase I – Development of the methodology; in particular this phase aims to:

- Highlight the importance of the internalization of environmental costs in integrated electric utility planning
- Identify methodological difficulties facing developing countries while carrying out the monetary evaluation of environmental damage
- Discuss strengths and weaknesses as well as the applicability of two methods, i.e. damage cost method and abatement cost method
- Set up a process of applying the abatement cost method, including basic assumptions, data requirements, modelling, validation of results
- Set up a process of applying the damage cost method, including basic assumptions, data requirements, modelling, validation of results
- Set up guidelines when one method is given priority over the other

Phase II – Application of the methodology recommended above to the case of power plants in Thailand, which consists of the following issues:

- To collect data about the power sector in Thailand, including technical data, operational and economic data; data about emission reduction technologies implemented in Thailand
- To apply the abatement cost method to estimate the incremental costs of reducing major pollutants (SO_2 NO_x and particulate matters)
- To apply the damage cost method to estimate the cost of health damage due to air pollution from one selected power plant (e.g. lignite power plant at Mae Moh)
- To compare the results obtained by both methods
- To draw conclusions about the applicability of the two methods in the context of developing countries

These two phases will be followed by dissemination of the findings:

Preparation of the final report

A regional workshop to discuss and disseminate the results of the projects

4. Proposed duration of the project

1 year

5. Project sites

Bangkok – Thailand

Chiangmai – Thailand

Lampang Province – Thailand

Denmark

6. Project cost

Total cost: US$ 408,691

7. Potential collaborating or participating organizations/individuals

Electricity Generating Authority of Thailand (EGAT)

EGAT will assist the AIT project team in obtaining the best understanding of the generating system in Thailand through data collection and field visits. The assessment of EGAT about the system performance and future development plan of the system is a vital input for the project.

National Energy Policy Office (NEPO) of Thailand

NEPO will participate in coordinating with other Thai institutions for data collection, in recommendations of the policy options derived from the results of the project in the energy planning procedure of Thailand.

College of Public Health/Chulalongkorn University

The College of Public Health of Chulalongkorn University will assist the AIT project team in obtaining the best understanding of the impact of air pollution on the public health quantitatively. It also will assist the AIT project team in analysing the relationship between air pollution concentration and health impact in the Thailand case study.

Thailand Environment Institute (TEI)

TEI will participate in applying the methodology in the case of Thailand, including participation in data collection, model testing.

UNEP Collaborating Centre for Energy and Environment (UCCEE)

UCCEE will cooperate with AIT in methodology development, particularly in drawing the experiences from similar studies done in industrialized countries, and incorporating the specific conditions of developing countries.

II. NARRATIVE DESCRIPTION OF THE PROJECT

1. Background

Production of electricity in Asian developing countries is increasingly rapidly exceeding the average growth rate of 10 per cent per annum. Fossil fuels are still the main source for electricity generation in these countries (e.g. China, the Philippines and Thailand). Air pollution from power plants burning fossil fuels causes damage to the environment. A significant part of these damage costs are not accounted for in the new capacity selection process and therefore may distort the allocation of resources. To account for this damage, their monetary values must be quantified. This exercise is known as quantification of environmental externalities. Asian developing countries are in need of the methodology allowing for carrying out this kind of exercise, the result of which will provide input for the internalization of externalities in power sector planning. This proposed project aims at providing an analytical framework for the quantification of environmental externalities of power production by proposing a suitable methodology and demonstrating its applicability in a country case study.

2. Project description

To achieve the goal specified above, the project will have two main tasks: (i) the first aims at setting up methodology; and (ii) the second applies the proposed method to the country case study (for example, case of Thailand). Therefore the activities of the projects include:

- Gathering of literature, analysis of the state of the art of the issue of environmental monetization with focus on the damage caused by the electric power sector. This aims at achieving the key analytical elements, which will contribute to the proposed methodology

- Analysing the energy-environment policies in Asian developing countries, the state of the art of the issue of internalization of externalities in these countries. This aims at identification of the need for and the potential uses of the proposed methodology and also the specific conditions of these countries
- Setting up the procedure for application of the abatement cost approach, with emphasis on: basic assumptions, data requirements, models to be used, and validation of results
- Setting up the procedure for application of the damage cost approach, with emphasis on: basic assumptions, data requirements, models to be used, and result validation
- Recommendations for the use of each of the approaches with regard to data availability, required accuracy, and potential uses of the results of the quantification problem
- Meeting with various organizations in Thailand to collect data, gather information for the application of methodology
- Applying, first, the abatement cost method to calculate the marginal abatement cost of reduction of SO_2, NO_x and particulate matters within the power sector; making the necessary sensitivity analyses
- Examining the possible dependency of the marginal emission reduction costs on various factors, such as technologies employed, basic scenarios and existing environmental regulations
- Examining various uses of the resultant set of marginal abatement cost curves of these three pollutants
- Applying the damage cost method to calculate the damage cost of a lignite fuel cycle in Mae Moh power plant, Thailand
- Examining the dependency of the result on the technologies, location, existing environmental legislation and other factors
- Comparing the damage cost with the marginal abatement cost to derive a possible conclusion about the closeness of the results of the two methods
- Recommendation of the method to be used and associated values of environmental externalities of the Thailand power sector
- Finally, the results of the project will be disseminated with the organization of a national/regional workshop

3. Qualification of project proponent and proposed participants

The Asian Institute of Technology is an autonomous, non-profit, international post-graduate technological institution located in Bangkok. AIT's mission is to take a leadership role in the promotion of technological change and its management for sustainable development in the Asian and Pacific region through high-level education, research and outreach activities which integrate technology, planning, and management. AIT has four schools, namely, the School of Environment, Resources, and Development (SERD); the School of Advanced Technology; and the School of Civil Engineering; and School of Management. Each school specializes in various fields of study. The Energy Programme under SERD consists of three fields of study: energy economics and planning, electric power system management, and energy technology. The topic of the proposed project falls under the energy economics and planning field of study, in which the energy planning central consultant team is specialized.

The Center for Energy-Environment Research and Development (CEERD-AIT) is within the School of Environment Resources and Development (SERD) of the Asian Institute of Technology. CEERD-AIT serves two purposes: on the one hand, as a training and research support unit in the energy-environment economics and planning field of study, and, on the other hand, as an implementing agency for research and training projects in energy-environment-related issues in order to strengthen the capacity of national governments and energy producers in the formulation of energy policies for sustainable development.

The Electricity Generating Authority of Thailand (EGAT) is the state-owned utility responsible for electricity generation in Thailand. EGAT supervises all the activities of this sector, including the operation and maintenance of power plants, system expansion, transmission and distribution electricity to MEA and PEA, and power purchase from IPPs, and from abroad.

The National Energy Policy Office (NEPO), a collaborating institution, which will participate in this project, serves as the secretariat to the National Energy Policy Council. The latter is the highest level organization involved in the energy-related policy decisions in Thailand and it is headed by the Prime Minister. NEPO is responsible for (i) preparation of the National Energy Policy and the National Energy Management and Development Plan for the National Energy Council; (ii) monitoring and evaluating the implementation of the National Energy Policy and the National Energy Management and Development Plan; and (iii) collecting data, monitoring and analysing the changing situation and trends in energy development in Thailand.

The Thailand Environment Institute (TEI) is a non-profit institution. Its main objectives are to: conduct and implement long-term policy research on natural resources and the environment which can lead to the formulation of national energy-environmental strategies; promote the leading role of business in reducing pollution in Thailand; analyse and disseminate reliable data and information to interested parties and the public; cooperate with national and international institutions in promoting environmental awareness at both the national and global levels.

The Public Health College, Chulalongkorn University, is a specialized academic institution in the field of public health. It has conducted several studies investigating the impacts of air pollution on the human health. With its expertise and experience, the College will play an important role in this project.

CEERD-AIT is capable of conducting research on sophisticated methodological issues thanks to its strong and centralized research staff equipped with various methodological tools and computer models for research in energy-environmental studies. CEERD has long-time experience in conducting multi-institutional research activities, and most of all CEERD is renowned for its active involvement in energy-economic-environmental studies in Asian developing countries during the past several years. These activities include the Regional Energy Development Programme (REDP), which formulated and disseminated methodology for energy demand forecasting in relationship with economic development scenarios; and the Programme for Asian Cooperation on Energy and Environment (PACE-E), which provided the methodology for incorporating the environmental considerations in energy planning. After these two regional programmes, the development of methodology for the monetary quantification of environmental externalities and their implications, which answers the needs of countries in this region becomes imperative.

For the Thailand case study, the role of EGAT, NEPO and TEI is indispensable both in terms of providing country information and implementing policy options of the finding of the project. The country-specific data and information, analysis of the trends in economic-energy development, national environmental regulations are the important inputs for the country case study, which requires the close collaboration of local agencies.

The issue of environmental externalities of electricity generation has been investigated most comprehensively in the United States and also in the European Union. However, in developing countries, studies are few. In addition, the method, which is suitable for developed countries, to be applied to the context of developing countries requires additional treatment owing to different socio-economic, environmental, demographic and other conditions. This proposed project will add to the comprehensiveness of methodological issues of environmental externalities quantification in the developing country context.

This intended project is part of the joint activities between CEERD-AIT and the UNEP Collaborating Centre for Energy and Environment (UCCEE) Riso, Denmark. UCCEE, established in 1990, has the overall aim of promoting the incorporation of environmental considerations in energy planning worldwide, particularly in developing countries. UCCEE works catalytically, promoting and supporting research by local research institutions, coordinating projects and disseminating information, as well as carrying out a full in-house research programme in close collaboration with other colleagues at the Riso National Laboratory and internationally. UCCEE, moreover, has extensive experience in capacity-building activities.

CEERD-AIT will work closely with UCCEE on this project. UCCEE, which has committed itself to shouldering a significant portion of the funding requirements, will provide a specialist in energy environmental externalities analysis with experience in both abatement cost and damage function cost methods. UCCEE will also contribute with information and experience from the ExternE programme – the project on externalities of energy conducted in the European Union.

4. Project outputs and dissemination

Since the objectives of this project are to design a suitable methodology applicable for the estimation of the environmental externalities of electric sector in developing countries, the expected outputs will be solid guidelines, which clearly show: (i) in what conditions, for what purpose, one valuation method (the abatement cost method or the damage cost method) should be given priority over the other; (ii) the procedures, analytical models to employ the selected method to obtain the desired quantitative values; and (iii) finally, how to interpret the estimated values.

In addition, one part of the project output will be the estimated environmental externalities of power generation in the country case study, e.g. Thailand. These estimated values could be used by the utility, regulators and academic cycles as well. Two means of dissemination are envisaged: through the publication of the research report, and through a national/regional workshop.

5. Project timetable

The tentative timetable for the first phase of the project, which has been presented so far, is as follows (see also table III.2).

Activity No.	*Period of time*	*Activity*
1	6 weeks	Methodological review, identification of developing country specific circumstances and difficulties in undertaking environmental externalities valuation
2	12 weeks	Methodological review, identification of basic assumptions, estimation procedures, result interpretation and validity of the damage cost method. This step include the verification of necessary models and software
3	12 weeks	Methodological review, identification of basic assumptions, estimation procedures, result interpretation and validity of the abatement cost method. This step include the verification of necessary models and software
4	12 weeks	Special address of the developing country context, make the necessary adaptation, adjustments of the two methods to be applied to developing countries. This step may include modification of models and software
5	9 weeks	Combination of results of previous steps, design final methodology
6	12 weeks	Data collection of the Thailand case study
7	24 weeks	Application of abatement cost method in Thailand case study
8	24 weeks	Application of damage cost method in Thailand case study
9	8 weeks	Preparation of the report of Thailand case study
10	8 weeks	Revision of general methodology with reference to the result of the Thailand case study
11	12 weeks	Final report preparation
12	1 week	Regional workshop

Table III.2 Project 2: Timetable of activities

No.	*Activities*	*Month 1*	*Month 2*	*Month 3*	*Month 4*	*Month 5*	*Month 6*	*Month 7*	*Month 8*	*Month 9*	*Month 10*	*Month 11*	*Month 12*
1.	Methodological review, identification of circumstances and difficulties in developing countries												
2.	Identification of basic assumptions, estimation procedures, validity of damage cost method, study of models to be used												
3.	Identification of basic assumptions, estimation procedures, validity of abatement cost method, study of models to be used												
4.	Necessary adaptation, adjustments of the two method for application to developing countries												
5.	Design of the final methodology												
6.	Data collection of the Thailand case study												
7.	Application of abatement cost method in the Thailand case study												
8.	Application of damage cost method in the Thailand case study												
9.	Preparation of the report of the Thailand case study												
10.	Revision of general methodology with reference to the result of the Thailand case study												
11.	Final report preparation												
12.	Regional workshop												

PART THREE

ENERGY INFRASTRUCTURE POLICIES AND ISSUES

IV. POLICY ISSUES AND MANAGEMENT OF STRUCTURAL CHANGES IN THE POWER SECTOR*

INTRODUCTION

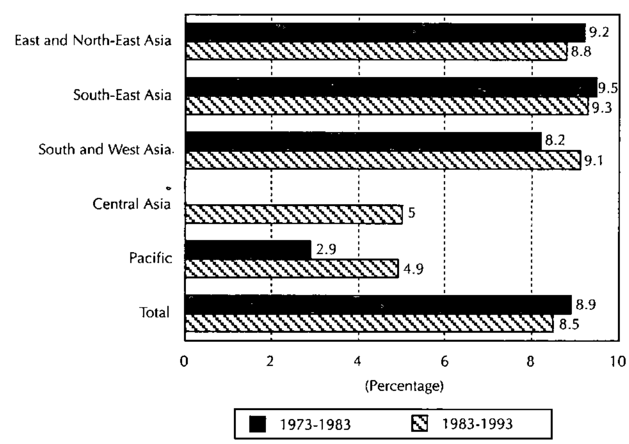
The purpose of this paper is to review the status and potential of electric power infrastructure in the Asian and Pacific region and put into perspective the structural changes that are evolving in the power sector in the region. An attempt has been made to look at opportunities and challenges that are being brought along with the changing power market structure and the power industry. Some issues have been raised that need to be addressed for allowing the integration of private sector projects into the overall development and management of the power sector.

The current situation of the power sector in the Asian and Pacific region, particularly in developing economies, is characterized by inadequate infrastructure, lack of financial resources but high demand growth for electricity. Another added constraint has been the environmental concern that has a consequence on fuel options for power generation. In the supply side, and even to a certain degree in the distribution or transmission system of the power sector, structural changes have been taking place from a monopoly to a competitive market. Deregulations or re-regulations are being made in many countries to make way for these changes. In the process, while some countries have done well, others are still struggling to get on board. Managing these changes effectively is the order of the day. There is scope for learning from the experience of each other in managing the changes.

A. PHENOMENAL ELECTRICITY DEMAND

To meet sustained high economic growth, the demand for electricity in developing economies of the ESCAP region has been growing at a remarkably high rate and this growth is expected to continue in the future. Electricity demand and production in the Asian and Pacific region have been increasing at a much higher rate than total energy consumption. Whereas in the 1980s overall energy consumption increased at an average annual rate of 5.2 per cent in the Asian and Pacific region as a whole, electricity production increased at a much higher rate during the same period. In developing economies, the situation presented even more of a contrast, with significantly higher growth in electricity generation (over 8.5 per cent as a group) opposed to a little over 6 per cent growth in total commercial energy consumption. Figure IV.1 shows the past trend in the region broken down to subregions of Asia and the Pacific.

Figure IV.1 Average annual electricity generation growth rate



Source: United Nations, *Energy Statistics Yearbook.*

The high growth rates of both energy and electricity consumption are due to the region's rapid economic growth coupled with its high population growth. With much demand as yet unmet, and consequent per capita energy and electricity consumption (figures IV.2 and IV.3) being at a very low level, as compared with industrialized economies, the high growth in electricity demand is expected to continue. As of 1994, the per capita electricity consumption in developing economies of the region was only 692 kWh, compared with 7,961 kWh of the industrialized economies of the region. Table IV.1 gives the situation of electrification in selected economies of the region. It is surprising, but a fact, that there are a quite a number of countries in which the access of the population to electricity is quite low.

* ESCAP secretariat, updated version of the paper presented at the Asia Power Conference, Singapore, 24-27 February 1997.

Table IV.1 Population access to electricity, selected Asian economies – 1990

(Percentage)

Bangladesh	12
Cambodia	33
China	66
Fiji	45
Hong Kong	100
India	80
Indonesia	24
Lao People's Democratic Republic	12
Malaysia	82
Maldives	77
Myanmar	6
Nepal	9
Pakistan	37
Philippines	61
Republic of Korea	100
Singapore	100
Sri Lanka	29
Thailand	71

Source: Asian Development Bank, *Electric Utilities Data Book for the Asian and Pacific Region* (Manila, 1993).

Figure IV.2 Electricity consumption, 1994
(kWh per capita)

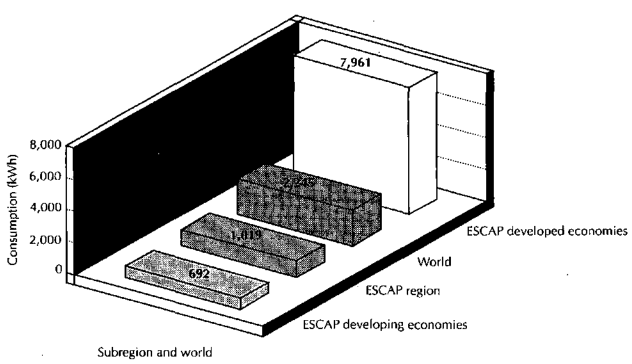
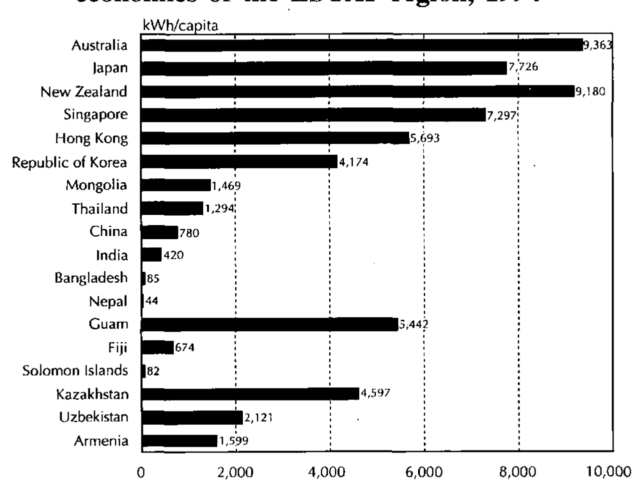


Figure IV.3 Per capita generation in selected economies of the ESCAP region, 1994



Source: United Nations, *1994 Energy Statistics Yearbook.*

B. FUTURE POWER NEEDS

Electricity, as a high-grade and clean form of energy, has many advantages in comparison with other forms of energy. Therefore, electricity production and consumption will continue to increase at a faster rate than overall energy demand. Over the years the electric power industry has become increasingly complex and capital-intensive. Many utilities in developing economies have seen phenomenal growth in capacity addition in the recent past. According to an ESCAP study[1], the projected installed capacity of developing economies of the Asian and Pacific region in 2000 was estimated to reach 735,478 MW (this figure has since been revised upward to 789,478 MW). The revised forecast of the likely electricity demand up to the year 2020 in the region, disaggregated to the subregional level, is shown in table IV.2 and figure IV.4. The table also gives possible shares of different types of fuel in the power generation.

C. ENORMOUS NEED FOR FUNDING

On the basis of an analysis in the above study, the ESCAP secretariat made an estimation that US$ 576-674 billion would be required for the supply of an incremental electrical power capacity of 327-385 GW in developing economies of the ESCAP region between 1990 and 2000. The corresponding Asian Development Bank (ADB) estimate of investment is US$ 500 billion for its member countries. The three largest contributors to the ESCAP estimate are China (US$ 143-181 billion for 102,000-129,000 MW), India (US$ 83-92 billion for 55,000-61,000 MW) and the Republic of Korea (US$ 42-46 billion for 22,000-24,000 MW). These three countries account for nearly 50 per cent of the total investment requirement. The estimate, which includes associated transmission and distribution infrastructure, is indicative and likely to vary from country to country and the type of power plants, environmental requirements and the plant siting. ADB estimates that the desirable limit for investment need in the transmission and distribution system is 40-45 per cent of the total investment in the power sector. As shown in table IV.2, with the installed capacity to grow at an average annual rate of 7.5 per cent during the period 2000-2010 and at 5.5 per cent thereafter up to 2020, the total installed capacity is expected to reach over 1,600 GW in 2010 and further to almost 2,800 GW in 2020 in developing economies

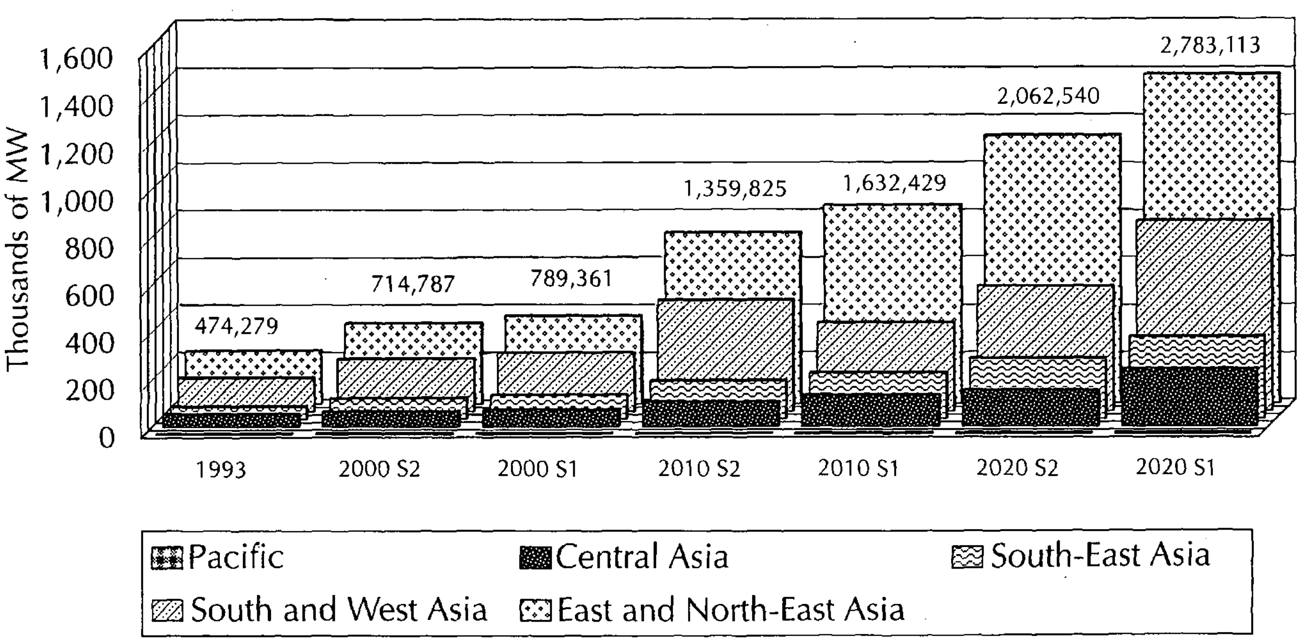
[1] ESCAP, *Infrastructure Development as Key to Economic Growth and Regional Economic Cooperation* (ST/ESCAP/1364).

Table IV.2 Asian and Pacific developing economies: future electricity generating capacity breakdown
(High-growth scenario)

Energy source	*1993 (Percentage)*	*Actual*	*Forecast/estimate 2000 (Percentage)*	*Capacity (MW)*	*2010 (Percentage)*	*Capacity (MW)*	*2020 (Percentage)*	*Capacity (MW)*
Primary	26.3	124 727	26.2	206 813	27.0	440 756	33.0	918 427
Hydro	23.7	112 397	23.5	185 500	23.0	375 459	23.0	640 116
Nuclear	2.4	11 382	2.4	18 945	3.0	48 973	5.0	139 156
NRSE[a]	0.2	948	0.3	2 368	1.0	16 324	5.0	139 156
Secondary[b]	73.7	349 522	73.8	582 548	73.0	1 191 673	67.0	1 864 686
All sources	100.0	474 249	100.0	789 361	100.0	1 632 429	100.0	2 783 113
Average growth rates			**7.5**		**7.5**		**5.5**	

Source: ESCAP estimates based on World Bank, *World Tables* and United Nations, *Energy Statistics Yearbooks.*
[a] Generating capacity which utilizes new and renewable sources of energy.
[b] Mostly steam power; the diesel and gas turbines contribution is in the range of 5-6 per cent.

Figure IV.4 Projection of installed capacity growth in the Asian and Pacific region
(developing economies)



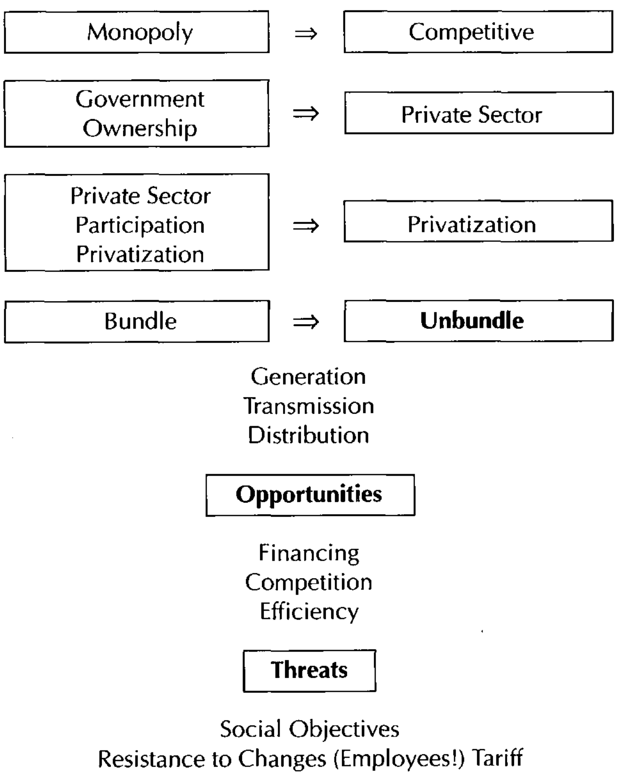
Sources: World Bank, *World Tables* and United Nations, *Energy Statistics Yearbook.*

of the region. Hence the investment need is huge but the traditional funding sources are limited, with only a fraction of the requirement likely to be met by them.

D. EVOLUTION OF THE POWER INFRASTRUCTURE

A recent major policy change noticed in the energy sector, particularly in the electricity sector, is in the investment and ownership pattern: private sector participation is increasingly seen as a source of funding in developing countries. With the rapid social, political and economic changes in the region, many governments are now increasingly opening up their state-owned economic sectors to private sector participation. This trend has been quite visible in the power sector in recent years, particularly during the 1990s. Whereas in the past, most, if not all, utility power sector investments had been based on public sector loans with state guarantees, more and more governments of developing countries, including those from Asia, are now turning to the private sector for the development of new electric power generating capacity. Figure IV.5 shows the evolution of the power infrastructure investment and ownership pattern over the years and the likely future trend.

Figure IV.5 Evolution of structural changes in the power industry



E. PRIVATE POWER

Private sector funding, being often non-recourse, may have positive impacts on the balance of payments. While many sectors, such as communications and construction (infrastructure) have been opened to private sector participation in a number of countries, the recent development of IPPs in a number of countries has made headway in the capital investment market for the power sector.

While the above development has attracted a great deal of interest, implementation has proved to be complex and difficult and as a consequence only a few countries have succeeded in getting independent power generation projects under way so far. Although there is a mixed feeling from the investors' point of view regarding their successes or failures in the financial closing or implementation of projects, it is obvious that the potential market is too big to be ignored. The trend is therefore that the concept of IPPs or, for that matter, private sector participation in the power infrastructure business, is here to stay. Therefore, understanding the difficulties encountered by investors and governments is essential if the private power business is to reach its potential in meeting the needs of populations of developing Asia and allow for continued, sustained development. A few of the major problems in most of the developing countries need to be resolved. These include a rational and transparent policy on private power, a pricing policy consistent with the market, and a fuel and environment policy. The other important area that needs to be addressed simultaneously is how to achieve social objectives within the free market environment.

Countries in which significant private sector investments have taken place include Malaysia and the Philippines. On the other hand, there are some countries (e.g. India and Pakistan), where major efforts towards private sector participation are under way but not much progress has been achieved.

F. FUEL OPTIONS AND THE ENVIRONMENTAL IMPACT OF THE POWER INDUSTRY

As one of the largest commercial energy-consuming sectors, the electric power industry has environmental and health impacts, particularly in relation to the production of electricity, which has emerged as one of the significant issues in the development and management of the power system. In addition to the environmental impacts of mining,

Box IV.1 Current power infrastructure situation in Malaysia

Malaysia, an energy-producing and exporting country, has been following the four-fuel policy for many years as a part of its diversification policy away from dependency on oil alone: coal, oil, hydro and gas. Now it is in the process of adding a fifth fuel, new and renewable sources of energy. During the past few years the Government has been encouraging private sector participation in the energy sector, including the electricity and gas subsectors.

Malaysia has been successful in launching a massive IPP programme in operation. As a result within a short period of time (1994-1996), a total of over 4,100 MW, or almost half of the generating capacity of the National Electricity Company (TNB) has been added by IPPs. The system maximum demand (1995) being at around 6,381 MW, there is currently a capacity-surplus situation of almost 50 per cent. However, with the demand growing at an average annual rate of 10-11 per cent, the excess capacity will be used up by the year 2000.

So far the IPP plants are operating with good performance records. As the experience with private sector dealing was new in the country, all the contracts were unsolicited and negotiated rather than through an open bidding process. Currently TNB is purchasing all the electricity generation of IPPs based on an agreed price under power purchase agreements (PPAs).

While the above scenario appears to be a success from the point of view of the private sector participation in power generation, from the TNB perspective it had been an unfair deal. TNB being the buyer of all power from the IPPs, the PPAs concluded between them are said to be more in favour of IPPs. As TNB is still the provider of T and D facilities, seller to customers and revenue collector, its profits have been declining as the tariff was not allowed to be adjusted corresponding to the cost increase. TNB also believes that with similar incentives given to IPPs, they could also be competitive in generation. On the other hand, the system losses in TNB are still considered relatively high and the Government wants it to reduce costs through reducing system losses. Another problem is the question of who supplies electricity to rural areas. The cost of supplies there being high and revenue collection being low, rural electrification is considered a social service. TNB has requested the Government to allow it to revise the tariff according to the reality.

Box IV.2 Current power infrastructure situation in India

India, an energy-producing but also an energy-importing country, has been trying hard to cope up with the high energy demand growth, a part of which has remained unmet for many years. That situation is generally due to the inadequate energy infrastructure capacity addition needed for the sustained economic development. Although India has large energy resources, such as coal and hydropower and some amount of oil and gas, production, transport, handling and distribution facilities of coal are inadequate and often based on age-old technologies. Its indigenous energy supplies (production) are not enough to meet the growing energy demand resulting in the importation of a huge amount of crude oil and oil products. Although India has abundant coal reserves, the transportation of coal from the mining area to the load centres is a major obstacle to its increased use. Moreover, most of the steam coal is of poor quality with high ash content. These supply constraints, together with lack of adequate financial resources, have had an impact on power generation.

As at the end of fiscal year 1995/96, the total installed generating capacity was 83,288 MW, with thermal power's share of 60,087 MW or over 73 per cent of the capacity[a]. Power demand, with a significant amount still unmet, has been growing at a high rate of about 7 per cent (eighth plan, 1992-1997) with an estimated shortfall of 7.1-11.2 per cent in energy demand and peak demand and 16.5-20.5 per cent of peak demand. However, the implementation of the policy generally lies with the State Electricity Boards. Although India has been successful in initiating an ambitious IPP programme, it ran into difficulties in putting together projects that needed commitment at the state level. Proposed IPP projects remain mostly unimplemented for lack of a coherent policy at the state level. In that respect, an Agenda of Chief Ministers has been proposed to agree on a policy that will keep politics out of the power sector.

Though the initial response of domestic and foreign investors was encouraging, the project development activities for several of the proposed projects that were initiated could not be concluded successfully and a number of them have encountered unforeseen hurdles.

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[a] *India's Electricity Sector – Widening Scope for Private Participation*, Government of India, Ministry of Power, 4th edition 1996.

transport, and handling or harvesting these primary energy sources, environmental pollution takes place in their conversion to as well as use of electricity. One of the reasons for environmental concern is the dominance of fossil fuel use in power generation. Energy sources used for electricity generation include coal, oil, natural gas, hydropower, nuclear and, to a lesser degree, other forms of new and renewable energy, such as geothermal, wind and solar energy. Tables IV.3 (A) and (B) show the breakdown of installed generating capacity and generation by type of fuel in the world and the ESCAP region.

The share of primary energy use in electric power generation has also been increasing steadily over the years. As of 1990, the share of primary energy used for electricity generation out of the total energy supply had reached a range of between 27 and 41 per cent in various subregions of Asia and the Pacific.[2] Many environmental pollutants can be controlled within acceptable limits but unfortunately at a high cost, which in some cases is prohibitive. Given the changing circumstances towards stringent environmental standards, the investment in the power sector is likely to be affected. However, the emission of green house gas (GHG) can be reduced only through increasing energy efficiency and using low-carbon or no-carbon fuel. Primary electricity (hydro, nuclear, geothermal and electricity generated from renewable energy sources) is ideal for that purpose but some of these sources have other environmental implications. Tables IV.4 and IV.5 give some of the environmental emission elements and their impacts by types of power generation on the environment. Depending on how the policy on environment evolves, hydropower and

[2] Asian Development Bank, *Energy Indicators of Developing Member Countries of the Asian Development Bank* (Manila, 1992).

Table IV.3 (A) Generating capacity breakdown of the power industry in the ESCAP region, 1994

Source of energy	*ESCAP region*		*Developed economies*		*Developing economies*		*World*	
	MW	*Percentage*	*MW*	*Percentage*	*MW*	*Percentage*	*MW*	*Percentage*
Primary	217 395	28.8	95 614	35.8	121 781	25.0	1 053 748	35.2
Hydro	162 869	21.6	54 430	20.4	108 439	22.3	698 315	23.3
Nuclear	52 459	7.0	40 531	15.2	11 928	2.4	345 626	11.6
NRSE[a]	2 067	0.3	653	0.2	1 414	0.3	9 807	0.3
Secondary[b]	536 783	71.2	171 478	64.2	365 305	75.0	1 937 464	64.8
Total	**754 178**	**100.0**	**267 092**	**100.0**	**487 086**	**100.0**	**2 991 212**	**100.0**

Source: *1994 Energy Statistics Yearbook* (United Nations publication, Sales No. E/F.96.XVII.8).

[a] Generating capacity which utilizes new and renewable sources of energy, including geothermal but excluding medium and large hydropower.

[b] Mostly steam power; diesel and gas turbines contribute around 4 per cent (5-6 per cent in developing countries).

Table IV.3 (B) Generation breakdown of the power industry in the ESCAP region, 1994

Source of energy	*ESCAP region*		*Developed economies*		*Developing economies*		*World*	
	GWh	*Percentage*	*GWh*	*Percentage*	*GWh*	*Percentage*	*GWh*	*Percentage*
Primary	867 605	26.2	388 096	33.3	479 509	22.4	4 664 751	36.8
Hydro	508 463	15.4	115 743	9.9	392 720	18.3	2 402 510	18.9
Nuclear	348 297	10.5	269 126	23.1	79 171	3.7	2 203 519	17.4
NRSE[a]	10 845	0.3	3 227	0.3	7 618	0.4	58 722	0.5
Secondary[b]	2 438 507	73.8	775 799	66.7	1 662 708	77.6	8 016 092	63.2
Total	**3 306 112**	**100.0**	**1 163 895**	**100.0**	**2 142 217**	**100.0**	**12 680 843**	**100.0**

Source: *1994 Energy Statistics Yearbook* (United Nations publication, Sales No. E/F.96.XVII.8).

[a] Generation utilizing new and renewable sources of energy, including geothermal but excluding medium and large hydropower.

[b] Mostly steam generation; diesel and gas turbines contribute less than 2 per cent (less than 3 per cent in developing countries).

perhaps nuclear energy are likely to play a bigger role in the future than today in supplying electricity. However, in the short and medium terms, fossil fuel, particularly coal and natural gas, would be increasingly used as fuels for power generation. The use of natural gas is constrained by the remoteness of the resources (often offshore) and its consequent infrastructure bottlenecks in transport and handling (pipeline network or LNG facilities). Coal, though considered a polluting resource, is likely to remain a dominant fuel for power generation for many years to come.

Table IV.4 Greenhouse gases

	Concentration (ppbv)	*Annual rate of increase (percentage)*
Carbondioxide	344 000	0.4
Methane	1 650	1.0
Nitrous oxide	304	0.25
Methyl chloroform	0.13	7.0
Ozone	Variable	–
CFC 11	0.23	5.0
CFC 12	0.4	5.0
Carbon tetrachloride	0.125	1.0
Carbon monoxide	Variable	

Source: United Nations, *Energy Policy Implications of the Climatic Effects of Fossil Fuel Use in the Asia-Pacific Region* (ST/ESCAP/1007).

Thus a growing concern of both the utility planners and IPPs is the degree of uncertainty in the national environmental policy. This has a direct consequence on the fuel options for power generation. Although the choice of fuels is influenced by the national fuel policy, depending on the target level of environmental standard on emissions, fuel substitutions are likely to take place. If more stringent environmental standards on emissions are stipulated, primary electricity is likely to play a bigger role in the future than today. During the past two decades or so, hydropower growth rates, in respect of both installed capacity and power generation, were trailing behind thermal generation, though in absolute terms the figures were substantial. As shown earlier in table IV.3 (B), in 1994 the share of thermal power generation in the Asian and Pacific region was 73.8 per cent, followed by hydropower, 15.4 per cent, nuclear, 10.5 per cent and others (geothermal and renewable energy resources), 0.3 per cent, compared with 63.2 per cent and about 19 per cent shares respectively of thermal power and hydropower generation respectively in the world. The share of nuclear power generation at the world level had been about 17.4 per cent.

Table IV.5. Illustrative environmental impacts of electricity supply

System component	*Key impacts*
Coal	❑ Groundwater contamination
	❑ Land disturbance, changes in land use and long-term ecosystem destruction
	❑ Emissions of SO_2, NO_x, particulates with air quality implications
	❑ Heavy metals leachable from ash and stag wastes
	❑ Global climatic change from CO_2 emissions
	❑ Lake acidification and loss of communities due to acid depositions
Oil and gas	❑ Marine and coastal pollution (from spills)
	❑ Damage to structures, soil changes, forest degradation, lake acidification from S and N emissions
	❑ Groundwater contamination
	❑ Greenhouse gas emissions impact, e.g. global climate change
Hydroelectric	❑ Land destruction, change in land use, modification of sedimentation
	❑ Ecosystem destruction and loss of species diversity
	❑ Changes in water quality and marine life
	❑ Population displacement
Nuclear	❑ Surface and groundwater pollution (mining)
	❑ Changes in land use and ecosystem destruction
	❑ Potential land and marine contamination with radionuclides (accident conditions)
Renewable sources of energy	❑ Atmospheric and water contamination
	❑ Changes in land use and ecosystem
	❑ Noise from wind turbine operations

Source: "Energy and electricity supply and demand", in *Senior Expert Symposium on Electricity and the Environment: Key Issue Papers* (Vienna International Atomic Energy Agency, 1991).

G. ISSUES IN MANAGING STRUCTURAL CHANGES

Reverting to the management of structural changes in the power structure, it is prudent to acknowledge that the private sector has an important role to play. As a matter of fact, a varying degree of success has already been achieved in a few countries of Asia. However, one should not be complacent; the market penetration has not been up to the level of expectation. A number of factors are responsible for this situation, such as the resistance to changes by utilities and their employees in particular, tariff policies and control, too little or too many regulations, funding constraints associated with credit ratings etc. In some cases, governments are also taking a cautious approach to giving away a vital infrastructure like electric power to the private sector. One of the issues that is often referred to is who bears the social responsibility for rural electrification, providing power to rural and urban poor. Another very relevant issue is the environmental externalities. Until such time as the public in general and all major players in the power sector achieve a greater degree of confidence in private power, it is likely that most of the developing economies will continue to keep significant control over the power sector. Even in countries where the IPPs are already very active, governments play a crucial role in creating a conducive atmosphere through proper regulation, including pricing and environmental standards.

With the rapid change in the power industry, the utilities are also reforming or adjusting to live with it. The power industry is being unbundled from its bundled or integrated system to components such as generation, transmission and distribution. While the generation and distribution components are already up for participation of the private sector or "threatened" to be taken over altogether from the utilities, it is expected that the present utilities will be transformed into facilitators in the future, perhaps ultimately keeping control over the transmission grid system to retain its role of coordinator and dispatcher. The often-talked-about term, the "grid code", is perhaps moving in that direction. The role of government as a regulator is likely to be maintained at all levels of privatization.

Finally, the environmental externalities need to be internalized into the power sector and preferably reflected in the pricing structure. It is to be noted that, no matter whether or not they are internalized, the society bears the consequences of environmental pollution or its degradation.

H. CHANGING DEVELOPMENT STRATEGIES

At a regional workshop held in 1994 and organized by the ESCAP secretariat, participants from 12 countries of Asia noted that while the opportunity for private sector participation in power generation was there, in promoting IPPs (private sector participations), measures should be taken to ensure that all parties stood to benefit from them[3]. Taking into consideration the specific country situation, each country would have to formulate its own policy according to its need. Countries will have to formulate their own strategies on how much regulated reform they would allow to meet their economic as well as social objectives. They will have to steer structural changes towards sustainable development.

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[3] Economic and Social Commission for Asia and the Pacific and United Nations Development Programme, *Private Sector Participation in Power Generation and Its Consequences on Environmental Quality (An Emerging Trend in Asia)* (ST/ESCAP/1515).

V. STRUCTURAL CHANGES IN THE GAS SECTOR*

INTRODUCTION

At the recent International Gas Conference held at Kish Free Zone Island, Islamic Republic of Iran in February 1997, the world gas outlook was reviewed. Three conclusions could be summarized from the discussions:

(a) Gas demand is expected to be technology-driven, influenced by the economics of combined cycle gas turbines for power generation, the demand for chemicals feedstock and, finally, the techno-economic breakthroughs achieved both in smaller scale LNG and in liquid middle-distillates derived from gas middle distillate processes using catalysts);

(b) While the demand shows a "supply gap" by about 2005, such demand is more likely to be from Asia than from Europe;

(c) LNG schemes on the drawing board at present are competing mainly for the Asian market and could be implemented early if power generation demands warrant it. However, because of the technological developments mentioned above, and the additional possibility of using "garbage oil" (treated and "cracked" waste oil and residues) in gas turbines (with similar efficiency as gas for power generation) the market will be quite competitive. It is the objective of this section of the paper to study the economics and politics of gas in Asia in the light of the expected competitive situation described above.

1. Economics of gas grid development

It is well known that in transport systems profitability depends on utilization rates of the capital assets. For instance, at a particular ship charter rate, carrying a cargo from A to B is normally expected to yield sufficient revenues to offer a "normal rate of return" on the capital asset (ship) to the owner. What if the operator can find a "back-haul" complementary cargo? His revenues would double, provided these were based on a set fee per ton carried between A to B. If the owner is the operator, his profitability would double.

How about a pipeline system? The same logic can be applied: financiers want guaranteed utilization and, since they are conservative, they would calculate their profitability at half utilization, assuming a linearly increasing demand and full capacity utilization only at the end of the contract period. This is illustrated in figure V.1 below, taken from notional calculations of an offshore pipeline in Brunei Darussalam some 25 years ago.

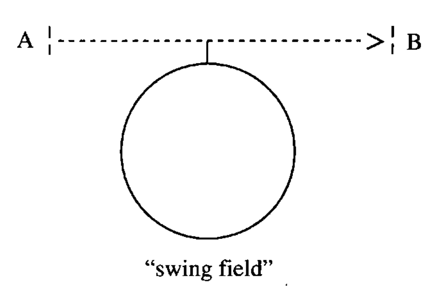
What now if a large field (or several small ones) can be connected to this trunkline from the start of operations? Provided only that customers can be found, the utilization rate can be increased and, in principle, revenues based on full utilization can be achieved at an early date. Since tariffs were set based on the "conservative" utilization assumption (guaranteed to bankers) of figure V.1, revenues to the pipeline (figure V.2) company could easily double, just as in the "back-haul" case of the shipping example. Moreover, utilization can be maintained longer (beyond the original contract period) using these additional

Figure V.1 Pipeline tariff and profitability A-B connection

A ¦---------------------------->¦ B

Tariff: US 50 ¢/mmbtu, giving "normal" return to pipeline investors, based on a 20-year contract, on the average half-loaded line (i.e. at half capacity after 10 years, full capacity after 20 years).

Figure V.2 Pipeline tariff and profitability A-B connection with an additional source/storage at C



Tariff: US 50 ¢/mmbtu (as before) however, now full utilization is possible from the start, using "swing field" both as an early source and as a last "storage" capacity.

* ESCAP secretariat, paper prepared for the Financial Times Gas Conference, Singapore, June 1997.

resources and using depleted fields for storage to "even out" demand – such as the case of the Groningen field in the Netherlands, for Norwegian and United Kingdom gas connected via the "Interconnector" to the European grid.

2. The politics of gas-grid interconnections

Politics is the art of the possible. Current assessment from a project proposal on a joint natural gas pipeline in South Asia presented at a workshop convened by UNDP Enhancing Regional Cooperation in South Asia through collaboration in Energy and the Environment and held Stockholm in July 1996 can be quoted as summarizing what it is hoped may be possible.

Notional figures given for independent and joint pipelines "assuming gas supplies from Qatar to Pakistan to India" as an example, are as follows:

Cost of independent pipeline, Qatar to Pakistan	US$	4-5 billion
Cost of independent pipeline, Qatar to India	US$	4-5 billion
Total cost of two independent pipelines (supplying both India and Pakistan)	US$	8-10 billion
Total cost of one joint pipeline (for same demand)	US$	6-8 billion
Cost-saving if the "art of the possible" is achieved, based on current progress of negotiations	US$	2 billion

The above savings illustrate the dramatic capital cost reductions that can be achieved once multilaterally negotiated political deals become possible for natural gas networks. Applying the same logic to one-to-one LNG versus multilateral pipeline deals, similar savings may well be achieved, on top of the "back-haul" economics of connecting several "sources and sinks" within the same gas network discussed above in the section on economics.

Although the incentive to negotiate such multilateral deals seems to be there, why do these take such a long time to negotiate? Some reasons are given in ESCAP (1994) reporting that such developments were discussed at ESCAP between experts from India, the Islamic Republic of Iran and Pakistan in June 1993. The reasons are still being discussed – though the idea to overcome technical, financial, and political obstacles through joint training and research activities was the original reason for proposing an Asian Gas Training and Research Centre (AGTRC).

3. The role of a gas centre: policy development, training and research for lower-cost solutions of energy supply and utilization through expanded gas grids in Asia

How do policies and regulations affect gas grid developments? How does training and research lead to a harmonization of policies? Following the report on international gas development in the International Gas Report (and, it is hoped, later on in the Asian Gas Report launched in Singapore in the first week of June 1997) it is apparent that a flurry of activities worldwide is taking place with more or less mature gas markets facing similar problems. Thus, there is a tremendous opportunity to learn from each other and thus avoid costly mistakes. This was the reason for the establishment of the United Nations Economic Commission for Europe Gas Centre in Geneva three years ago, for the benefit of the economies in transition in East-Central Europe and Central Asia. The results have been impressive, as also presented at Kish Island in February 1997 (see C. Simeoni and G.J. Kowalski, 1997).

The proposal for an Asian Gas Training and Research Centre presented at the same conference (see Torok, 1997) would extend such benefits to other Asian developing countries which have consulted before on related issues as members of the Natural Gas Working Group that has evolved through two UNDP/ESCAP intercountry energy and environment-related projects: the Regional Energy Development Programme (1982-1992) and the Programme for Asian Cooperation on Energy and Environment (1993-1997). It is time now to consolidate these efforts on a more permanent basis so that the political-economic and social benefits can be consolidated. In particular, legal developments could be addressed. If there are funds available, there could be a legal counsel at the Centre (as in the Energy Charter Secretariat in Brussels). The remit for legal research could be to review the legal regime (national-international law) in Asia; to identify obstacles to joint gas development projects; to develop a network of gas lawyers (Internet-linked forum) in Asia and develop legal forms facilitating intercountry gas development. The Centre would also be involved with legal, financial and technical training, drawing on commercially available resources and information exchange through, perhaps, a medium such as the Asia Gas Report, launched in Singapore.

4. Summary

An Asian Gas Training and Research Centre (AGTRC) could be established and incorporated in a host country as a non-profit corporation to facilitate legal, politico-economic, financial, and technical training and research needed for the establishment of multilateral gas infrastructure in Asia. Such a centre is also part of infrastructure in a broader sense: a facility to render "doing business" easier and at lower cost (and increased benefits) for both producers and consumers, in a clean and environmentally friendly international gas business.

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VI. MARKETING RENEWABLE ENERGY TECHNOLOGY*

Renewable energy sources display a remarkable potential for world energy supply. The potential for renewable energy to contribute to world energy supply in the twenty-first century is an important factor in the assessment of action to be taken for renewable energy development in the next few years.

Market development is crucial to the sustainability of renewable energy projects. Renewable technologies, including solar PV, must gain a market if their large potential benefits are to be realized. For example, it has been seen that the most successful PV dissemination programmes have concentrated on market development. Programmes which have begun indigenous production of PV modules before a large market has been established have not yet been as successful as those which have given their major emphasis to market development. Nevertheless, PV projects can progress from small, high-valued applications to successively larger markets, but this path is rocky when initial markets are thin and geographically fragmented. This is the situation encountered in most of the developing countries where the market of solar PV is limited by the lack of an effective marketing strategy.

The major drive for market development must be to develop incentive programmes to stimulate increased use of the technology. To be successful, the incentive programme must include a well-planned integration of technology push and market pull.

There are a number of impediments to the large-scale use of renewable energy around the world, but they all relate to market development. Therefore, understanding the constraints on marketing renewable technologies would greatly facilitate the renewable energy marketization process, to increase cost-effectiveness, and more importantly, contribute to the ability to develop a self-sustaining business structure.

1. Constraints on marketing renewable energy technologies

Results to date from renewable R and D and demonstration programmes worldwide indicate that there are market opportunities for most renewable energy technologies. However, like any new product entering a market, these technologies must be developed to customers' requirements, proved in the commercial environment and marketed effectively. This is particularly important for renewable energy technologies, in view of the diversity and complexity of the markets in which they must prove themselves to be competitive if they are to survive.

The markets in which renewable energy technologies are trying to establish themselves are complex, dominated by well-established technologies and influenced by the convenience of existing supply networks. There is also a persistent scepticism introduced by the prospect of using a new form of energy supply. Existing public policies are working against renewable sources of energy by heavily subsidizing conventional sources, especially in the rural areas. This creates the critical problem of how the potential of renewable energies can be realized in terms of a self-sustaining business sector. Owing to the current low prices and availability of fossil fuels, the high avoided cost conditions that led to the first wave of renewable electric generation no longer exist. Despite renewable technological achievements over the past decade, many renewable energy applications are currently too expensive to compete with fossil fuels, and for some applications, even if the cost of energy from renewable sources is reduced, institutional barriers would still prevent decision makers from responding to price signals. Under the current commercial environment, renewable energies find themselves being judged less on their long-term potential as contributors to diversification and more on short- to medium-term economic criteria in competition with well-established conventional sources. As many renewable technologies do not appear to meet accepted investment criteria, and therefore to stimulate wide-scale take-up, the public and private sectors (including the lender) begin to lose interest, especially for small-scale projects. If to the host of market-place problems are added the further socio-cultural and manpower constraints being encountered in the diffusion of renewable energy technologies, the challenge facing renewable marketing is indeed formidable.

* ESCAP secretariat.

2. Approaches to the issues

Renewable energies must appear as good investments and must match, or better, established technologies in terms of cost of delivered energy, reliability and convenience. To gain entry into the market in these circumstances there will need to be a substantial element of market pull in addition to the technology push provided by research, development and demonstration programmes.

To address the marketing issues, two approaches are suggested: commercialization and regional cooperation.

(a) Commercialization

Commercialization is a key factor in the wider diffusion of renewable technologies. Commercialization initiatives must be based on achieving sustainability through market forces. Towards this end, efforts should be devoted to commercialization through the marketing aspects of renewable technologies. Governments have to develop commercialization and marketing strategies for renewable energy in their countries. Commercialization efforts would require institutional strategies for harnessing public awareness, enhancement of local industry, appropriate market evaluation and marketability schemes together with facilitating regulation.

In the light of the experience gained from earlier programmes, the ESCAP secretariat has formulated a regional project on solar PV technology which aims to identify the socio-economic constraints as well as the impediments to realizing the commercial potential of PV technology, and to determine the ultimate approaches for their solution. A TCDC/ECDC programme will be developed and pursued in cooperation with the commercial sector utilizing the training aids, experience and equipment developed in the earlier work of ESCAP to provide regional countries with a sustainable capability to implement PV programmes and projects for environmentally sound integrated rural development rapidly. The projects would also address the main issues in solar PV diffusion. The main issues for consideration in a sample country case study are:

Institutional arrangements

The arrangements made for the installation, operation and maintenance of the project need to be considered. How public and private organizations are participating, how ongoing funding for operation of the project is obtained and what individuals or organizations actually are owners of the equipment used in the project are important to the project and its long-term success.

The development of solar PV systems requires good coordination between scientific, industrial and commercial activities through institutional arrangements. At the national level, such collaborative efforts involving research institutions, private equipment developers, and potential users, would promote solar PV technology simultaneously in the laboratory, factory and the field and would enhance the role of market forces in fostering solar PV development, as well as contribute to resolving the factual obstacles that affect the competitive position of solar PV in comparison with conventional sources. It would also upgrade the role of small- and medium-sized enterprises in the market penetration of solar PV technology, particularly in the developing countries.

Local participation

Involving local people in commercializing renewable technologies is critical to stimulating sustainable markets. Wherever possible, local entrepreneurs should be involved in adapting technologies to suit conditions, meet service needs, or reduce system costs – activities that not only produce local income and employment but also raise the odds of technology diffusion.

Most PV projects have been designed, specified, purchased and installed by overseas personnel with minimal participation by local persons. As a result, there remains a strong dependence on overseas assistance in the continuance of existing projects. Further, it has proved very difficult for local agencies to replicate successful projects. Motivation for much stronger local participation in all phases of project development and implementation is an issue for consideration.

For better market penetration, the solar campaign should give priority to the establishment and development of capacity at the local level for the manufacture, marketing, operation and maintenance, and management of equipment and spare parts related to solar energy.

Manpower development in remote areas

Inefficient outreach activities owing to inadequate manpower capabilities have been widely considered as one of the major reasons for the slow progress in the diffusion of new and renewable sources of energy. A longer-term sustainable development effort through training, capability-building and education at the grass-roots level needs to be encouraged to overcome these difficulties. Towards this end, efforts should be devoted to ensuring the training of adequate manpower through "training-or-trainers" training courses so as to ensure the transfer of the PV technology to end-users who, in most cases, are small farmers and villagers. In the field, these trained personnel would act both as trainers and managers in PV projects. The training can be continued by the trained villagers after the departure of the trainers.

For PV development projects to continue, it is essential that recipient countries have the capability to install and maintain PV equipment. The availability of technically qualified personnel at the recipient sites is a critical issue. Local training capability is therefore an issue for consideration.

Issues of commercial support

Commercialization is an appropriate approach to enable PV systems to gain wide acceptance in developing countries, particularly in remote and inaccessible areas. International organizations should assist governments in the region in developing commercialization and marketing strategies for solar PV in their countries. Strategies must be tailored to the needs and circumstances of each country, and will depend on the market sector and the customers being targeted.

For photovoltaic energy to proceed beyond the pilot stage of implementation, suppliers and manufacturers of PV equipment need to participate fully in market development and equipment support through market research, the development of supply networks and adequate warranty policies. Existing rural supply networks need to be examined as possible support networks for PV-based electrification. In particular, areas with a number of small individual petrol or diesel generators supplying households with lighting power are very likely to have both the need and the access to the supplies needed for successful PV electrification. The presence of commercial support for PV projects is a vital one for the expansion and full acceptance of the technology.

(b) Regional cooperation

For a sustainable supply of new and renewable sources of energy (NRSE) to all sectors of economic development, it is fundamental that NRSE activities undertaken by various national institutions be adequately coordinated and complemented by regional cooperation through networking arrangements. To address this issue, ESCAP promotes intercountry cooperation in the field of NRSE and in rural energy planning through the concept of regional working groups. The objective of the regional working group is to foster self-sustained intercountry cooperative initiatives. A cooperative arrangement among the regional countries in terms of subject-specific working groups in different areas of NRSE, including rural energy planning, is viewed as a viable approach to address issues relating to sustainable NRSE development collectively.

ESCAP has coordinated and assisted the countries of the region in the establishment of:

(a) Regional Working Group on Wind Energy Development and Utilization, secretariat based in China;

(b) Regional Working Group on Geothermal Energy Development and Utilization, secretariat based in the Philippines;

(c) Regional Working Group on Rural Energy Planning and Development, secretariat based in China;

(d) Regional Network on Small Hydro Power, based in China.

ESCAP is endeavouring to establish the regional working groups in the remaining areas of NRSE.

Multilateral collaboration bringing private investors into renewable ventures in developing countries could also be pursued. "Investment round-tables" could be organized. ESCAP could play a catalytic role in such an exercise through its various regional working groups in renewable sources of energy.

Through the coordination of ESCAP and the Regional Working Group on Wind Energy Development and Utilization, intercountry cooperation in the application of the small-scale wind energy conversion system is being implemented among China, Sri Lanka and Viet Nam in a TCDC/ECDC context.

Similarly, joint activities in the field of geothermal energy are being planned for China, the Philippines and Viet Nam under the coordination of the Regional Working Group on Geothermal Energy Development and Utilization and ESCAP.

3. Conclusion

Renewable energy programmes should look beyond the technologies and pay equal attention to social, institutional and financing issues, the resolution of which is often the prerequisite to commercialization. For example, even for commercially ready renewable technologies, the high initial cost of equipment and the dispersed nature of projects pose constraints on consumer acceptance and lender interest. It must be recognized that these constraints will remain, despite advances in technology. Instead of regarding these as an insurmountable barrier, the attitude should be to develop innovative management and financing packages to handle small-scale, dispersed projects. Efforts should be made to eventually establish in the developing countries the institutional framework required to identify, appraise, finance, manage and operate small-scale decentralized renewable energy projects.

Market development is crucial in sustainable renewable energy development. There are a number of impediments to the large-scale use of renewable energy around the world.

The international community may wish to consider a concerted effort in working towards an energy future making intensive use of renewable sources of energy. The United Nations system as a neutral and commercially unbiased participant may continue to play a facilitating role for effective project implementation.

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PART FOUR

ENERGY INFRASTRUCTURE PRICING POLICIES AND ISSUES

VII. ANALYTICAL OVERVIEW*

At the beginning of the discussion on the policy options for energy at the Expert Group Meeting on Energy Infrastructure and Energy Pricing Policies, the secretariat gave a verbal introduction based on a set of points distributed to the participants. The paper prepared by the secretariat based on those points is reproduced below.

This is followed by a brief review of the recommendations and the work of the Energy Resources Section of the ESCAP secretariat over the past 16 years with a view to drawing some lessons for the future.

A. POLICY OPTIONS ON ENERGY INFRASTRUCTURE

1. Purpose

The purpose of this paper was to serve as an introduction to the discussion on the above topic at the Expert Group Meeting. After presentation of the paper by the secretariat, the participants were invited to express their views and comments, and thereby to have an exchange of information on their experience.

2. The role of energy in development

Many developing countries of the ESCAP region recognize the crucial role of energy. Indeed, a statement to that effect was contained in the report of the Committee on Environment and Sustainable Development on its first session, held in 1993.

This has arisen from the conviction that energy consumption and the development of the national economy are closely related. Energy might be regarded as an input into the economy or the development process, and the statistical relation or correspondence between the two was almost always close. Based on time series data, for most developing economies in Asia and the Pacific the income elasticity of energy consumption lay between 1.1 and 1.5, with the correlation coefficient of nearly unity.

Similar considerations apply to electricity, which was perhaps more often regarded as an input into not only the development process, but even the modernization process. In this case the income elasticity of electricity consumption was higher, usually in the range between 1.5 and 2.0, and sometimes even higher than 2.0.

Because of the close relationships between both energy and electricity consumption and economic development, any constraints on energy supply lead automatically to lower energy consumption and hence to lower economic growth. Hence the importance of the energy infrastructure: it ensures the availability of energy and electricity supply, and is therefore a prerequisite to economic growth.

3. Energy infrastructure: energy system and institutional structure, consisting of producers, transporters/distributors and consumers

It may be useful to have a common understanding of the term "energy infrastructure". The word "infrastructure" is normally associated with the physical plants and/or structures and buildings. In the energy sector, these are more commonly held to lie within the supply side, that is, those physical facilities and plants associated with the three stages of production or mining, the transformation or refining and the transport and distribution or transmission of energy commodities. Thus they include coal mines, offshore oil platforms, refineries, all sorts of power plants (thermal, hydro and nuclear), transmission lines and pipelines, oil tankers and coal barges, etc. It is also normal to include the transport infrastructure, such as roads, trucks, ships and ports, and fuel storage sites.

More recently, the demand side has come into the picture, as demand-side management has been found to be a potentially powerful management tool. The demand side is where the energy users and energy consumers lie, and they are usually categorized into a number of sectors: the industrial, transport, commercial and household sectors. Other sectors are the government sector, sometimes combined with the commercial sector, and the agricultural sector, sometimes included in the industrial sector. The industrial sector may be further subdivided into its component industries, such as steel, glass, cement, food etc. or sometimes according to its intensiveness

* ESCAP secretariat.

(in terms of energy). Within each of these sectors the energy users have to use various kinds of equipment which have variable efficiency and which require capital expenditure. Thus it makes sense to include this capital expenditure in the considerations for overall energy sector management.

To enable the capital expenditure on all equipment for energy use to be included, it is necessary to include in the definition of "energy infrastructure" the laws and regulations governing the energy sector along with the institutional structure that produces and periodically reviews these laws and regulations. The latter include the legislature, the commissions or committees established to regulate the industry, and ministries or agencies that implement the provisions in the laws and regulations.

Thus the major players in the energy sector in many developing countries are usually the public sector utilities and state-owned companies that are mandated to produce and sell energy, such as electricity, oil and coal. In a number of countries, oil and oil products are handled by foreign oil companies; these have also been allowed to enter the power sector recently, particularly on the generation side.

The demand side is represented by both the private and public sectors, the largest being consumers in industry, the owners and managers of commercial buildings and hotels, owners of transport companies (buses and trucks), and, most numerous, the private households and owners/users of motor vehicles.

4. National development planning and prerequisites

There are a number of prerequisites that must be met before a programme of sustained national development planning and implementation can succeed. Foremost is a system of stable government, and its accompanying economic and currency stability. In other words, a system of good governance is needed and an enabling climate for investment. These are difficult to achieve in a developing country setting, which by definition is the setting for continuing economic structural change, shifting from a predominantly traditional and agricultural society to a commercial, modern and industrial society.

One important choice a country needs to make is on the control of the public sector and the role of the private sector in the economy. This is decided by its ideology; the usual question is posed through the choice between central planning versus laissez-faire. The choice of the country determines its course in its management of the energy sector and energy infrastructure.

Most countries would aspire to a set of desirable long-term goals and development strategies in its economic development plans. These would relate to some development imperatives such as sustainable economic growth, full employment, enhanced quality of life, and equitable distribution of income. Inherent in these is the necessity to address environmental concerns. These choices would also become important determinants of the country's future energy developments.

Somewhere in the development plans lie the country's infrastructure development plans. As indicated earlier, these would include the country's choice of projects, such as refineries and expansion of distribution systems for oil products, and power plants, transmission systems and expansion of electrical distribution systems. The plans should also include plans for human resources development in the energy sector, which are frequently neglected.

5. Policy options

What then are the policy options for the decision maker? The principal determinants of the energy future, at least those that are within the purview of a country's decision makers, are the political choices. One concerns subsidies, for both petroleum products and electricity tariffs or rates. Subsidies are normally designed to enable the poor sections of society to obtain access to energy supplies. However, for energy-importing countries, subsidies entail expenditure of valuable foreign exchange; for energy-exporting countries, subsidies mean foregone opportunity costs.

Another political choice is the role of the private sector: many developing countries still retain the energy sector companies and utilities within the public sector, for historical or legal reasons. In the petroleum sector, multinational oil companies have worked for a long time in the exploration and production of oil and gas in developing countries. In this case, most of the developing countries have no choice, for they not only lack capital but do not possess the technology and know-how. The companies are invited as contractors.

The situation in the power sector is different. The introduction of the private sector into the generation side of power utilities is a recent development, mainly for reasons of obtaining additional sources of capital investment, i.e. the additionality factor, as opposed to the introduction of competition for the sake of economic efficiency. To date, the private sector has not been invited in a big way into the transmission and distribution side in developing countries.

Another political choice may be termed the "political will" of a country to develop its indigenous technology. It could be part of an overall national industrial strategy. The energy sector could be used as a vehicle to pursue this aim, and hence the country's policies would incorporate elements of technology development in its long-term energy plans. There are many difficulties, of course, in formulating and implementing such policies. As an example, the power utilities would prefer to build, install and operate only technologies and plants which have been proven, technically and commercially, and would tend to reject newly developed, and by definition unproven, technology.

Another development strategy could be rural development strategy, whereby the development of rural energy is utilized as a vehicle to enhance or to accelerate rural development. In this case the energy sector is to be used as a tool for rural development. Usually, the formulation of such a strategy would require studies to be undertaken first.

In recent years, the phrase "sustainable development" has come into more common usage, especially since the Earth Summit of 1992, as has the phrase "sustainable energy development". Many, however, use the term "sustainable" in the sense of "sustained growth", which, in the long run, is unsustainable. Thus "sustainable development strategy" has become a politically appropriate strategy. It is associated with the idea that the environment is to be integrated within the country's development strategy, planning and implementation. While many of the environmental concerns are local and regional in character, some are global concerns, such as depletion of the ozone layer and the accumulation of greenhouse gases, possibly leading to global warming and rise in sea level.

With regard to energy and power development strategy, some of the policy options, based on the above discussion, are the following.

6. Energy resource options

Oil and gas Oil remains the most convenient form of energy, readily available on the market. Foreign companies to be invited for exploration and production; oil product distribution may be entrusted to the public and/or private sector (including foreign) companies; for annual consumption of greater than about 50,000 BPD, investment in refineries may be considered.

Coal Most conveniently used for power generation. National mines could be developed; foreign participation may be invited for speedier development. If locally available, could be used for industrial and domestic sectors.

7. Energy sources for power generation

Coal versus gas Coal is readily available on the international market, but requires a coastline and preferably deep harbour facilities. Gas is less readily available and requires long-term commitment (involves pipeline or LNG tankers and facilities), but it is the cleaner fuel.

Hydro and geothermal These are natural resource endowments for power generation without CO_2 emissions, but also not without opposition.

Nuclear energy The only other non-CO_2 emitting option, but with considerable public acceptance problems.

Regional cooperation Little evidence of regional energy trade in Asia and the Pacific when compared with Europe, where gas pipeline and electric power networks span the whole continent. Advantages: economies of scale, common use of resources, less capital requirements, higher supply stability etc.

8. Security of supply

Many countries understandably place great importance on security of supply. However, choice of fuels (oil and coal) and producers (Middle East and Australia) is limited. The technology for using energy is also "fixed" by industrialized countries (e.g. motor vehicles).

9. Environmental protection

There is mounting pressure, national and international, to integrate environment and development. It is becoming imperative to introduce unleaded gasoline and eliminate emissions from industrial and power plants, specially particulates, SO_2 and CO. Desirable for developing countries to develop strategies to comply with the convention on limiting greenhouse-gas emissions, in future to be legally binding.

10. Role of price

Energy should be inexpensive (priced low enough to stimulate industry) and affordable, if necessary through cross-subsidies (so that the poor can obtain access); but it should not be cheap, otherwise it would lead to wasteful use and energy suppliers would be less commercially viable. Environmental protection measures should be included in the price.

B. POLICY RECOMMENDATIONS FOR ESCAP MEMBERS

The rudiments of a coherent regional strategy for managing developments in the energy sector in the ESCAP region over the next 10-15 years may emerge from the above analysis. This might be somewhat different from the strategy recommended some 16 years ago by the Committee on Natural Resources, which at the time had been concerned with the then likely demand growth prospects and the expected structural changes arising out of the two oil crises of the 1970s. The accepted paradigm then was the necessity for an energy transition from fossil-fuel based energy systems towards one based on new and renewable sources of energy. For the convenience of readers, the measures identified then are briefly reproduced here.[1]

Major components of a strategy include:

(a) A coal-based economy (to replace the expected increase in import requirements) based on indigenous and regional (Australian and Indonesian) coal;

(b) The replacement of a possible shortfall in indigenous oil production by imported LNG and/or methanol wherever feasible;

(c) A gradual transition from an "imported methanol-based" energy economy to an indigenous, renewable, biomass-derived methanol economy;

(d) Rural developments of solar, wind, minihydro energy sources.

It will be observed that there are some similarities between the early 1980s and today. First, the coal economy is fast becoming a reality, even outside China and India, with a number of countries opting for it for power generation. Second, the LNG market has expanded considerably in East Asia, and may expand further into South and South-East Asia.

There are also some differences, which may be summarized as follows. First, most of the urgency for an energy transition seems to have been lost. Additional oil and gas resources have been found since then (North Sea, Alaska, Mexico, and some smaller developments in Australia, China, India, and Malaysia), as well as revisions of oil resources in the Middle East. On top of that, the reserve/production ratio for coal is still much larger than that for gas and oil. Thus, the energy transition horizon has been shifted further into the next millenium, which may be one of the principal causes for the deceleration in the development of new and renewable sources of energy. Second, the environment is more and more seen as a restraining factor in the development process, as additional capital expenditure is being called for to provide for its protection. This was observed by the Committee on Environment and Sustainable Development at its third session in 1996. Third, methanol has failed to penetrate the market to any significant degree.

In the past 16 years since the eighth session of the Committee on Natural Resources, ESCAP has endeavoured to undertake the suggested studies which were originally aimed to facilitate the energy transition programme:

Study on coal logistics in the ESCAP region

Study on the beneficiation of coal through the "coal centre" ("coal-plex") concept

Ethanol/methanol/methane from biomass

A study tour of existing LNG/LPG/methanol projects

[1] See *Proceedings of the Committee on Natural Resources Eighth Session, and of the Regional Expert Group Meeting on Follow-up of the Nairobi Programme of Action on New and Renewable Sources of Energy* (Energy Resources Development Series No. 25).

Modelling long-term energy scenarios for the ESCAP region

Projects to develop mass-produced solar/wind components

Most of the studies contemplated 16 years ago have now all been completed, as documented in Nos. 32-35 of the Energy Resources Development Series and in *ESCAP Energy News* and other publications funded through extrabudgetary resources. Nevertheless, the challenge facing the energy sector today would seem to be vastly greater than it has ever been, not least in the areas of infrastructure and pricing developments – the main concern of the present publication.

VIII. ENERGY INFRASTRUCTURE PRICING POLICY AND ISSUES*

The Asian and Pacific region is a fast-growing economy. The economies of the region have demonstrated general sustained dynamism. Most of the countries have adopted relatively successful market-oriented outward-looking policies and have achieved higher economic growth rates. This trend is expected to continue. Higher economic growth has stimulated energy demand in the region. The region's demand for energy has been the highest in the world for the last two decades.

The strong relationship that exists between energy and economic development in the Asian and Pacific region makes comprehensive energy planning imperative, but the distortions and uncertainty involved in the energy market make such planning increasingly difficult.

The main objective of the present paper is to provide a brief overview of the energy demand in the Asian and Pacific region and discuss mainly the issue of energy infrastructure development with respect to the pricing policy.

A. DEMAND

The demand for energy by source is given in table VIII.1. Energy consumption in the Asian and Pacific region is expected to grow by an average annual rate of about 3.2 per cent as against the world demand growth rate of 1.7 per cent between 1990 and 2020.

There are a number of reasons for the higher energy demand in the region. The economies of the region are growing rapidly; the industrial sector is expanding significantly; and the agricultural sector has become more commercialized. The increase was also due to higher population growth and rapid urbanization. The substitution of commercial energy for traditional fuelwood and charcoal substituted by kerosene and LPG also raised the share of energy demand.

The table also shows that the share of natural gas in the energy-mix is expected to rise from about 8 per cent in 1990 to 12 per cent in 2020. The prospects for natural gas development is bright because of the short life of oil reserves, declining oil production, rising environmental concern and a relatively high reserve life of natural gas. A similar trend is expected in the world demand-mix in the future.

Table VIII.1 World energy demand by source

(Percentage)

	1990		*2020*	
	World	*Asia and the Pacific*	*World*	*Asia and the Pacific*
Oil	35.9	32.3	32.8	27.5
Natural gas	22.3	7.9	25.2	12.0
Coal	30.1	50.8	26.4	47.0
Nuclear	5.7	3.8	6.9	6.4
Hydro	6.0	5.3	8.0	7.1
	100.0	**100.0**	**100.0**	**100.0**
Total demand in million tons of oil equivalent	8 807	2 289	13 359	4 497

Source: World Energy Council, 1993.

As electricity is a higher form of energy, its consumption is often regarded as one of the measures of economic progress. Per capita consumption of electricity in developing countries averages approximately 500 kWh, compared with about 7,000 kWh in OECD countries. Developing countries whose per capita electricity consumption is low have to increase the supply of electricity even to keep pace with the present economic development. Their demand for electricity is growing at a rate of approximately 7 per cent a year (World Bank, 1990).

Coal is the major source of energy in the Asian and Pacific region, accounting for almost 50 per cent of energy consumption. China is the major consumer and producer of coal, accounting for almost two thirds of the production and consumption of coal in the region.

The growing demand for energy has created enormous investment requirements, but the energy pricing policy of governments constrains financing. Energy prices are usually lower than the international prices or long-run marginal cost in most of the developing countries. Intervention in energy pricing is made to generate revenue for the government, to

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improve income distribution and to minimize the import bill. But these criteria conflict with the objective of economic efficiency and discourage private sector participation in energy development. Low prices help to make energy more affordable but can also result in a level of revenues inadequate to cover costs or finance future supply expansion. Governments' ability to finance the increasing need for energy infrastructure development is also diminishing, mainly owing to the higher growth rate of energy demand and declining foreign assistance.

B. ENERGY FINANCING AND INVESTMENTS

Growing investment requirements worldwide have become one of the major issues of the developing countries. According to one estimate, about $60 billion per year will be needed for the oil and gas sector and about $80 billion per year for the electric power sector during the period 1991-2001 in the developing countries. Out of these investments, about 42 per cent is required for the oil and gas sector and about 63 per cent of the total power sector investment is required for the developing countries of the Asian and Pacific region. The potential investment required in the developing countries of the region also accounts for about 23 and 36 per cent of the worldwide investment required for the oil and gas and power sectors, respectively. These estimates will be higher if the economic growth rates are projected higher than what would have been projected in the trend analysis (Sharma, 1994).

In the past, most energy enterprises in developing countries were financed by public funds, either through the use of public credits or through direct transfers from the taxpayers. High rates of economic growth enabled the governments to raise tax revenues and at the same time the international capital market was expanding. Most of the developing countries also took advantage of petro-dollars produced in a period of low interest rates. Furthermore, easy access to credit and a strong financial position allowed governments to borrow to meet development needs, including the expansion of energy industries.

However, the situation changed in the early 1980s. Governments started facing problems in meeting their debt burden and international credit markets contracted, resulting in rising real interest rates. This problem has become even more acute in the 1990s. Out of the total investment requirements, only 20 per cent is expected to come from the multilateral agencies; 80 per cent of the financing has to come from domestic sources.

Energy is a highly capital-intensive industry. For the last two decades, the energy sector's share has been, on an average, about 25 per cent of the total government expenditure in the developing countries, but this was not enough to meet the energy demand in these countries. Therefore, the scale of future investment demands for the energy sector could become higher to provide adequate supplies of energy – especially electricity. In the meantime, if the present trend continues, almost three fourths of total energy supply investments are projected to be in foreign exchange.

The challenge, therefore, will be to develop the energy resources and facilities required to satisfy the needs of developing countries while adapting to the new global financial order.

Distorted pricing policy is the main impediment for the private sector's participation in energy infrastructure development. The energy price to customers in most of the Asian developing countries is still smaller compared with the long-run marginal cost of supplying energy, especially electricity.

1. India

Energy prices are highly subsidized in India. The gross electricity subsidy for fiscal year 1996/97 has been estimated at Rs 194.94 billion ($5.5 billion), registering a 46 per cent jump over the total electricity subsidy in 1994/95. The share of the agriculture sector is about 76 per cent of the total subsidy. The subsidy rates have been rising for both the agriculture and domestic sectors, because the unit cost has been increasing faster than the relevant tariff rate. The inter-state distribution of the per capita electricity subsidy indicates that the per capita subsidy is substantially higher in richer States as compared with that provided to the poorer States (*Economic Times,* 7 May 1997).

In recent years, India has also opened up its power sector to private investors and the State Electricity Boards have agreed to pay 5-6 US cents at generating points to independent power producers. Transmission and distribution losses and overhead costs of the Boards are to be added to this price to arrive at the price paid by the consumers for the power generated by IPPs. But the average revenues realized at present by these Boards from their consumers are in the range of 3.5 US cents. The average rate of return of the Boards for 1996/97 was – 17.9 per cent.

Similarly, the total petroleum subsidy for 1996/97 has registered a 100 per cent jump and reached Rs 184.40 billion ($5.2 billion). Subsidies are given in kerosene, high-speed diesel and LPG. In terms of both magnitude and rates, the hike in the subsidy has been phenomenal. The subsidy to kerosene, diesel, and LPG increased by 169, 1,940 and 138 per cent respectively, between financial years 1994/95 and 1996/97.

The relatively low price of diesel, kerosene and LPG has increased the consumption of these products, significantly. Diesel consumption increased by about 42 per cent between financial years 1991/92 and 1995/96. The demand for other subsidized petroleum products also increased dramatically during the same period.

The demand for kerosene, which is met through imports (56 per cent) and a large proportion distributed through the public distribution system, is mainly for cooking. However, kerosene usage for cooking was only 1.34 per cent in rural households.

2. Indonesia

Some of the recent electricity-pricing studies show that the retail price of electricity has been kept below cost and the State Electricity Corporation (PLN) has relied on government subsidies to cover its losses. Sudja (1993) argues that since PLN receives a subsidy from the Government, the price of electricity will have to increase if the private sector has to be made involved in the power sector development. The main reasons for the increase in price are the need for private equity investors to receive a high rate of return on equity and the inability of private power developers to obtain loans at interest rates as low as those the Government can obtain.

Sudja's analysis shows that with the existing arrangements in 1993, PLN had a generation cost of US¢ 4.11 per kWh compared with US¢ 6.02 per kWh for the private developer for building a 1,200 MW coal-fired steam power plant. The private sector cost was thus 46 per cent higher than the PLN cost. However, in recent years, the power sector loan by the World Bank and ADB have been at floating rates determined by market conditions, but the opportunity cost of the Government of Indonesia in equity funds has not been addressed in the analysis.

Another study, by Kristov (1994), also shows that the cost of supplying electric power was 45.5 per cent higher than the PLN average sales revenue in Indonesia for the period 1980/81 to 1993/94. This conclusion is based on assuming devaluation, market interest rates on loans from domestic sources, a market rate of return on equity and 25 per cent of earnings retained for funding system expansion.

Thus, to attract the investment of the private sector in the power sector and to make PLN commercially viable, the large traditionally hidden government subsidies must be eliminated. This implies that tariff revenues will have to be adequate to cover all costs associated with commercial viability.

3. Nepal

The existing energy price structure in Nepal neither provides incentives for private investment in developing energy infrastructure nor encourages efficient use of energy. The economic prices and retail prices of electricity, kerosene and diesel on grounds of equity considerations have resulted in market distortions ranging from product adulteration (kerosene with motor spirit) to uneconomic fuel switching (Delucia and Associates 1993).

Among the petroleum products, kerosene, diesel and LPG are priced below cost price. Gasoline is heavily taxed. However, even with these arrangements, Nepal Oil Corporation, which is the only organization to import and distribute oil products in the country, is losing NRs 100-120 million every month.

Electricity is priced above the cost price at present. However, if one considers the opportunity cost of government funds invested in this sector, the price of electricity is also subsidized in Nepal.

Biomass is the dominant source of energy consumed in the country. The share of traditional forms of energy in the overall energy consumption is estimated to be about 91 per cent. Fuelwood is the major energy source within biomass. Fuelwood is still the cheapest alternative by a wide margin (table VIII.2). Fuelwood-gathering is a non-monetized activity. Most of the households gather fuelwood "freely", if the labour cost is not included. The only price the gatherers pay is the time. The cost of fuelwood is only about 18 and 40 per cent of that of kerosene and electricity in terms of useful energy. This price is not sustainable for fuelwood production or conservation.

Table VIII.2 Costs of household fuels in a typical hill village, 1994

Fuel	*Price (Rs/unit)*	*Calorific (Mj/unit)*	*Price (Rs/Mj)*	*Efficiency of combustion*	*Price (Rs/Mj)*
Fuelwood	0.25-1.0/kg	16.7	0.015-0.06	10	0.15-0.6
Kerosene	12-16/lit	3.5	0.34-0.48	45	0.76-1.1
Electricity	3.8 kWh	3.6	1.06	50	2.12

Source: Perspective Energy Plan, 1995.

If governments want private developers to invest in the energy sector, the private sector should be allowed to earn a modest rate of return on its investment based on the true cost of generating power. However, if the prices are not rationalized, governments have to subsidize the utility. This will increase the debt burden of the country significantly, as the energy sector has been the largest producer of the governments' foreign debt.

Therefore, to attract private investors in the energy sector, distortions in electricity pricing must be eliminated. In the meantime, new investments can be attracted only if the policy for setting prices of power purchased from private producers are reasonable.

In addition to the pricing policy, a number of other factors are affecting infrastructure development adversely. However, there are certain common factors responsible for the poor performance of the energy sector, some of which are government interference in the management of utilities, lack of trained manpower, overstaffing, lack of standardization of equipment, limited planning, distorted pricing structures, political pressure to sell electricity at less than cost, and regulatory frameworks that discourage competition. Among these, interference in the day-to-day management and pricing policies are identified as major institutional problems.

According to one World Bank report government interference has adversely affected least-cost investment decisions, hampered attempts to raise prices to efficient levels, mandated low salaries tied to civil service levels and promoted excessive staffing. This in turn has resulted in inadequate management, weak planning, inefficient operation and maintenance, high losses and poor financial monitoring controls and revenue collection.

C. ENVIRONMENT

The production and use of energy contribute negatively to the environment. It is widely believed that if the present trend of energy consumption continues, it will create environmental problems which, in the longer run, could become a constraint on economic growth and social well-being.

There are three broad but distinct environmental issues related to energy. Pollution related to energy mining and transport comes under the first category. Pollutants like methane and sulphur dioxides are emitted from energy mining, whereas oil spills are caused mainly by the transport of crude and products. Oil spills are still considered a major environmental anxiety. The discharge from day-to-day transport of oil from tankers, pipelines and offshore platforms is also high.

In the second category is the problem of clean air; combustion of fossil fuel generates a variety of pollutants which affect human health and the natural environment. Combustion of biomass, which is the main source of cooking and heating in rural areas, produces smoke containing particulate, polycyclic organic materials and carbon monoxides etc., which are hazardous to human health. The impact is greater at the household level and affects more women and children.

Similarly, fossil fuel-fired power plants also give rise to several local and regional problems. In addition to the emission of sulphur oxides, nitrogen oxides, carbon monoxide, carbon dioxide and particulates, the power plants engender the problem of acid rain. Acid rain can harm trees, agricultural crops, the aquatic biota and other vegetation. In addition to the physical environment, acid rain can also affect human health. However, the damage caused by acid rain to the physical environment and human health differs from place to place and depends on acid precipitation. It is a local as well as a regional problem.

Third, but the most important, is the problem of greenhouse gases. Carbon dioxide, methane and nitrous oxide, which are the main greenhouse gases, are emitted mainly from the combustion of fossil fuels. Energy is estimated to account for more than 50 per cent of the global greenhouse gases.

Similarly, the rate of deforestation in many countries is high. The loss of forest is contributing to soil erosion and degradation, fuelwood and fodder shortages, increased flooding and loss of biodiversity. It is also contributing to the greenhouse gases.

There are a number of policy options available for reducing energy-related environmental problems. Increasing energy efficiency and conservation are the most important means of reducing such problems. Clearly, one way of influencing the efficiency energy use is through the prices being charged for oil products. In the past, consumers have enjoyed subsidized prices for energy products in many countries in the region. These practices distort market forces and lead to higher energy consumption. Subsidies must be phased out and tax must be introduced in order to internalize the environmental externalities arising from the excessive use of energy.

D. POLICY OPTIONS

In view of the enormous financial, technological and human resource requirements, private sector participation in the development of the power sector has become a necessity. The power sector needs to be restructured so that the system can be unbundled, competition introduced and private sector participation maximized.

Examples from some of the countries show that power generation, transmission and distribution can be separated. The private sector may own and operate power plants. Owners of the plants which are located either inside the national grid or outside may sell power directly to end-users.

Most of the countries have followed the build-own-operate transfer (BOOT) scheme of project development and ownership, in which private owners build, own and operate the plants for a number of years. Power is sold to the country utility via a long-term power purchase agreement. Ownership of the plant is transferred to the utility following a predetermined number of years, in which the private sector owner has retired the debt for the plant and earned an adequate return on investment. There have been instances where other schemes, like build-operate-transfer (BOT) and build-own-operate (BOO), have also been used in the hydropower sector. The other option, build-own-sell (BOS), has been used only occasionally in the renewable energy system.

There are three main policy options available in reducing the problem of financial constraints on future energy development.

First, there is a wide range of opportunities for private sector participation in the energy sector. The private sector must be attracted and its resources be mobilized to supplement the governments' efforts to develop the energy sector.

Second, energy efficiency can be improved significantly in the developing countries in a cost-effective manner. Sustained efforts in this direction could reduce demand growth significantly, thus reducing the investment burdens.

Third, electricity prices lag behind supply costs significantly in most of the developing countries. The pricing policy must be such that the rates of return on power sector investment are comparable with those on similar alternatives. Further, an institutional mechanism must be introduced to make the energy system competitive.

E. IMPEDIMENTS TO PRIVATE SECTOR INVOLVEMENT

Although legislation and regulations have been introduced to attract private investment in energy in most of the developing countries, there are still a number of problems, including financing, construction, operating and political risks.

There are two components to the financing risk: the foreign exchange risk and the interest fluctuation risk. A large portion of investment capital is required in foreign currency (typically 50-80 per cent), especially in hydroelectric projects: the government should provide the necessary foreign exchange for investment and also assure the availability of foreign exchange for the remittance of profits. Interest rate fluctuation could be a risk and devaluation of local currency could also be a problem for private investors.

Construction risk arises if the project is not completed within the budget and on schedule. This could be due to the unavailability of construction materials, differences between estimated and actual costs, delay in construction owing to bureaucratic problems, and so on. Operational risks include technical risks and marketing risks. Technical problems affect the reliability of power supply. Market risks include fuel price and availability (if the energy is thermal) and power dispatching.

Entrepreneurs also perceive greater political risk in most of the developing countries, including Nepal. Potential private investors are concerned that the government may not be willing to raise the price of electricity to keep up with the risk in capital, fuel, labour and maintenance costs. In most of the countries the only client for power is the government and investors have no options if they become dissatisfied.

The unavailability of funds for long-term borrowing is another hurdle. Usually, banks loan money to the power sector for a relatively short period (10-15 yeas), but the life of the power projects are much longer (25-35 years). The main reasons for which do banks not go for long-term financing is the political risks involved. If the debt had to be repaid in a short period of time, the electricity price would obviously have to be higher. However, the regulation does not allow for such an increase in price.

The impediments to private sector power development must be reduced and financial resources and technical expertise have to be attracted. Measures, which include legislation, policies, institutions and regulations that inhibit and discourage investments in the energy sector, must be improved.

F. ROLE OF THE GOVERNMENT

Monopolies over ownership of energy industries and management must be reduced and, wherever possible, market forces must be allowed to work.

Markets that can be made competitive should be deregulated. Some of the obvious areas where deregulation is desirable are the generation and distribution of electricity, the import and distribution of oil products, and the marketing of fuelwood and other tradable commodities. However, in many instances, even deregulation of a certain sector may cause it to be transferred from monopolistic to oligopolistic markets and thereby give rise to cartels and anti-competitive practices.

On the other hand, there are certain natural monopolies (e.g. transmission of electricity) or legally protected monopolies (e.g. import and distribution of oil products at present) where regulation should act as a market substitute and management efficiency should be fostered by the government.

The private sector can participate in a variety of energy sector activities, specifically in production and distribution, and can help the government free resources for more pressing social needs.

The government's role in the changed situation must focus on formulating indicative planning, regulating natural monopolies and supervising competitive markets. In addition, it should play a key role in protecting the environment by introducing environmental regulations and monitoring their enforcement.

G. REGIONAL COOPERATION IN ENERGY

Cooperation in energy can help to share energy resources and technology, increase energy trade and investment and improve environment quality.

Cooperation in the natural gas sector can be expanded significantly in South-East Asia as well as in South Asia. Endowments like hydroelectricity and coal provide opportunities for increased interconnection in electricity and trade in coal in the region.

Table VIII.3 Petroleum product prices, 1993
(US cents per litre)

City	*Gasoline*	*Diesel*	*Kerosene*
Bangkok	33.93	31.19	35.23
Colombo	71.74	25.33	19.13
Dhaka	34.21	34.38	34.38
Islamabad	42.22	19.65	19.26
Jakarta	26.67	13.82	10.67
Kuala Lumpur	40.58	24.92	25.31
Manila	41.64	27.89	27.89
New Delhi	56.47	19.51	9.73
Seoul	77.37	26.64	32.22
Singapore (Fob)	16.90	–	–

Source: World Bank (1995).

Table VIII.4 Electricity tariffs in the Asian and Pacific region
(US cents per kWh)

Country	*Residential (small)*	*Industry (medium)*
Bangladesh	4.23	6.28
Bhutan	1.53	1.53
China	3.25	2.41
India	4.49	12.96
Indonesia	5.09	6.05
Malaysia	7.66	7.24
Nepal	1.85	4.93
Philippines	5.98	9.97
Republic of Korea	3.89	4.72
Sri Lanka	2.28	4.78
Thailand	4.13	6.99
Viet Nam	4.26	4.26

Source: World Bank (1995).

Table VIII.5 Energy investments, 1991-2001
(billion of US dollars)

Energy	*Developing countries of the Asian and Pacific region*	*Other developing countries*	*World total*
Oil and gas	250	350	1 100
Power	500	300	1 400
Energy Equipment for conservation	30	12	84
Total	**780**	**662**	**2 584**

Source: World Bank and US Department of Energy.

The growing use of energy is creating greater awareness of environmental issues. Energy conservation, improved efficiency and recycling have become important matters related to the environment and energy development. Asian countries which are at different levels in terms of environment-related problems and capabilities should share their expertise and knowledge with each other and work closely in the area of local, regional and global energy and environmental issues.

H. CONCLUSIONS

Mobilizing financial resources to meet the growing investment need has become the major concern in most of the developing countries. The demand for energy, including electricity, is growing rapidly. The magnitude of the financial resources required to meet the projected demand will be enormous.

The multilateral institutions which are helping the developing countries in financing energy development are not likely to go much beyond the past trend. Thus, private financing would seem to be the only potential financial source to fill the gap.

Distorted energy pricing policy is the main impediment to private sector participation in energy infrastructure development. The retail price of energy in most of the developing countries is still smaller than the long-run marginal cost of supplying energy. The private sector can participate in energy development only when the energy prices are adequate to cover all costs of energy generation.

The government's role, on the other hand should focus on regulating natural monopolies and supervising competitive markets. Governments should improve legislation, policies, institutions and regulations which generally inhibit or discourage investments in the energy sector. The constraints on attracting foreign capital must be removed.

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PART FIVE

SITUATION ANALYSIS BY AND VIEWS OF PARTICIPANTS

IX. AN OVERVIEW OF PARTICIPANTS' VIEWS*

Participating country presentations and information notes (by participants) are given in full. In this overview, some common problems will be highlighted and some areas suggested in which further studies may well be required before policy recommendations can be attempted. The most extensive and detailed coverage of practical problems is given by Bangladesh (A.N.M. Rizwan), Sri Lanka (country paper) and Thailand (Amorn Phundhu-Fung on infrastructure and Koomchoak Biyaem on electricity) as well as Japan (Taizo Hayashi and Ministry of International Trade). What is apparent from these is that eclectic solutions for both tariff-setting and investment inducement policy (IPPs) have to be found and that although problems are similar, resource endowments (and thus solutions) may well be quite dissimilar. Gas-based generation appears to be least-cost – as long as there is gas. Nuclear energy has been studied, but only the currently nuclear States (China, India, Japan, Pakistan, Republic of Korea) have firm plans to continue with it, while others (Bangladesh, Indonesia, Thailand etc.) are still considering it as a "last option" owing to public acceptance difficulties. Although it is recognized that pricing developments need to render the energy sector viable for private investments in electric power (IPPs), it is indeed a daunting task to achieve such pricing while also leaving energy at affordable prices for the poor and in an environmentally "clean" framework.

An excellent technical analysis of these issues was given by the two participants from the Asian Institute of Technology, summarized below.

Professor Ram M. Shrestha, acting Chairman of the AIT Energy Technology Programme in his presentation, "Issues in avoided cost pricing of IPP power: a sensitivity analysis" gave model-based results on how and why "avoided" cost estimates for utilities in power purchase agreements might be under (or over) estimated, inhibiting (or enhancing) IPP entry through economic decision criteria into the national power supply system, and also indicated how much cost estimates were likely to evolve in time at different IPP penetration levels.

There are different objectives when considering IPPs: Japan mainly wants to lower electricity tariffs through competition, while India, Pakistan, Sri Lanka, Thailand etc., only want to raise capital on private markets. Professor Shrestha's summary of approaches for pricing IPP power is reproduced below.

(1) Individual negotiation

- ❑ Price and other terms arrived at bilaterally
- ❑ Useful at initial stage of IPP development
- ❑ Risk of buyer and seller collusion
- ❑ Protracted negotiation

(2) Competitive bidding

- ❑ Price determined by market forces
- ❑ Difficulty in securing competitive bidding
- ❑ Bids received in ad hoc fashion owing to vague offer
- ❑ Standard benchmark required to compare offered price

(3) Standard offer by utility

- ❑ Cost-plus pricing
- ❑ Avoided cost pricing

(4) Combination of (1), (2) and (3)

This analysis would tend to favour approach (2) for Japan, while (4) (a combination) for developing countries.

A most interesting (if somewhat disheartening) analysis was given by Romeo B. Pacudan, also of AIT, entitled "Incorporating environmental costs in power project assessment: an evaluation of prospects in Asia and the Pacific". His point was that because when trying to quantify environmental costs, most of the time people do not know (with sufficient accuracy) what they are talking about; to include these in integrated resource planning is more than likely to be misleading and lead to a mis-allocation of resources. It is not that one should give up on the objective of "clean energy", but should, perhaps, approach it with

* ESCAP secretariat.

more humility. What is needed is ongoing research, and in the meantime (while decisions must be made) only some "rules of thumb" can be offered:

Prospects in environmental policy of the power industry in Asia and the Pacific:

1. In the light of the dire need for private capital in power supply expansion in many countries, environmental policy must meet both environmental and investment goals.

2. To meet these objectives, the principles of consistency, transparency, clarity, cost-effectiveness and timeliness should guide the development of environmental practice in the planning, development and operation of electricity infrastructure.

3. Incorporating environmental costs in the decision-making process has still a long way to go before it can be considered in the region.

4. The governments in the region could strengthen their existing environmental policies and perhaps could adopt other market-based policies which would possibly achieve environmental goals at least cost.

X. ENERGY INFRASTRUCTURE AND ENERGY PRICING POLICIES: BANGLADESH SCENARIO*

INTRODUCTION

Bangladesh, a country of teeming millions, is facing an acute power crisis. For a developing country, power is most essential element to industrialize the country and to advance its economy. Only 15 per cent of Bangladesh's 120 million population has now access to electricity and per capita generation is only 96 kWh or 8 kgoe for the fiscal year 1996. It is therefore a foregone conclusion that Bangladesh has to go a long way in power sector in order to enable its economy to take off. It has become imperative in this background that Bangladesh needs to take stock of its energy infrastructure, adopt policy to develop it and make best use of the resources. At the same time, to encourage private participation in the power sector, a rational pricing policy needs to be adopted.

A. SCOPE

In this short paper attempts will made to study the energy infrastructure of Bangladesh in terms of energy sources like coal, oil, gas, hydro, nuclear and renewable energy and the energy industry in the power sector with its related issues. The current situation, evolving trend, future plan for optimum utilization etc. will be focused. The issue of energy pricing, its present position and future action will be discussed briefly. Conclusions will be drawn based on the study during the paper.

B. OVERVIEW AND EVOLVING TREND OF THE INFRASTRUCTURE

1. Organizations

Bangladesh Power Development Board (BPDB), a semi-government organization, is entrusted with the responsibility of generation and transmission of electricity throughout the country. BPDB is also responsible for distribution in most of the areas of Bangladesh, except Dhaka Metropolitan City and its adjoining area and some of the rural areas. Responsibility for distribution in the above two areas lies with Dhaka Electric Supply Authority (DESA) and Rural Electrification Board (REB) respectively, both of which are semi-government organizations.

2. Installed capacity

BPDB has an installed generating capacity of 2,908 MW against an estimated demand of nearly 2,300 MW. Many of the power stations have outlived their economic life while some others are out of commission for lack of timely maintenance. The total installed capacity and present capability of each power station is shown in table X.1. About 300-450 MW of generating capacity were not available for the generation of power during the summer of 1997 for shortage of gas. Thus, a severe load shedding from 300 MW to 450 MW had to be done during peak hours. The situation is now gradually improving with the implementation of a rehabilitation programme of about 360 MW-capacity old power stations. Planned future load generation balance up to the year 2005 is shown in table X.2. A typical daily load curve is shown in figure X.1.

3. Generation and consumption pattern

Most of the BPDB generation is gas-based. Statistics for the fiscal year 1996 show that gas-based generation was 87.10 per cent, oil-based 6.46 per cent and hydro generation was 6.44 per cent of the total generation. Consumption of the net generation by BPDB, DESA and REB for the same year was 43.78, 39.34 and 12.76 per cent respectively. Figures X.2 and X.3 show the generation and consumption pattern. End consumption by category of the above three utilities for the same year is shown in figure X.4.

4. Transmission lines and sub-stations

At present, BPDB has 419 km of 230 kV, 2,469 km of 132 kV and 167 km of 66 kV transmission lines. For distribution purposes, BPDB has 8,233 km of 33 kV and 27,580 km of 11 kV and below lines. Information on transmission lines is shown in table X.3.

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* A.N.M. Rizwan. The author is working as General Manager, Commercial Operation, Bangladesh Power Development Board. The views expressed in the article are those of the author and not necessarily of the Board. The author wishes to acknowledge the extensive help he has received from the Power System Master Plan (PSMP) and the reports of M/s. London Economics on power sector reform.

Table X.1 Installed and present capacity of the existing power plants
(as in May 1997)

Name of the power station	*Unit*	*Unit type*	*Type of fuel*	*Installed capacity (MW)*	*Present capability (MW)*
A. East Zone					
Karnafuli Hydro	1	Hydro	Hydro	40	
	2	Hydro		40	40
	3	Hydro		50	50
	4	Hydro		50	45
	5	Hydro		50	45
Ashuganj	1	ST	Gas	64	40
	2	ST		64	
	3	ST		150	
	4	ST		150	140
	5	ST		150	150
	1	CT CC	Gas	56	140
	2	ST		34	
	2	CT	Gas	56	
Siddhirganj	1	ST	Gas	10	6
	2	ST		10	
	3	ST		10	
	4	ST		50	20
Haripur	1	CT	Gas	33	30
	2	CT		33	30
	3	CT		33	30
Ghorasal	1	ST	Gas	55	45
	2	ST		55	45
	3	ST		210	190
	4	ST		210	190
	5	ST		210	200
Shahjibazar	1-7	CT	Gas	96	46
Fenchuganj	1	CT	Gas	30	30
	2	CT CC		30	30
	3	ST		30	
Sylhet	1	CT	Gas	20	20
Rauzan	1	ST	Gas	210	200
Sikalbaha	1	ST	Gas	60	50
	BMPP-1	CT		28	
	BMPP-2	CT		28	
Total East Zone				**2 405**	**1 812**

Table X.1 *(continued)*

Name of the power station	*Unit*	*Unit type*	*Type of fuel*	*Installed capacity (MW)*	*Present capability (MW)*
B. West Zone					
Khulna	1	ST	F. Oil	60	
	2	ST	F. Oil	110	60
	BMPP-1	CT	SKO	28	21
	BMPP-2	CT	SKO	28	
	1	CT	HSD	13	10
	2	CT	SKO	10	10
Bheramara	1-2	CT	HSD	40	30
	3	CT		20	
Saidpur	1-2	D	F. Oil/LDO	11	2
	3	D	F. Oil/LDO		
	1	CT	HSD	20	20
Bogra	1-2	D	HSD	5	1
Thakurgaon	1-7	D	LDO	10	3
Barisal	1-7	D	HSD	8	2
Rajshahi	1-3	D	HSD	3	1
Barisal	1	CT	HSD	20	20
	2	CT	HSD	20	20
Rangpur	1	CT	HSD	20	20
Bhola	1-2	D	F. Oil	6	3
Baghabari	1	CT	HSD	71	71
Total West Zone				**503**	**294**
Total				**2 908**	**2 106**

Table X.2 Future load-generation balance

* According to the PSMP study, the peak demand will increase from 1,995 MW in fiscal year 1995 to 3,149 MW in fiscal year 2000, 4,597 MW in fiscal year 2005 and 6,779 MW in fiscal year 2010.

* To meet the increasing demand, the Power System Master Plan (PSMP) recommended immediate implementation of some generation projects.

* The load generation balance up to fiscal year 2005, considering existing, under construction, committed and new projects, will be as follows.

(Megawatt)

	1997	*1998*	*1999*	*2000*	*2001*	*2002*	*2003*	*2004*	*2005*
Peak demand	2 419	2 638	2 881	3 149	3 394	3 659	3 947	4 259	4 597
Generation capability	2 440	3 351	3 392	3 991	4 311	4 719	5 075	5 425	5 868
Reserve margin	–	27.02%	17.74%	26.74%	27.01%	28.97%	28.58%	27.38%	27.65%
Firm capacity <1	1 884	2 795	2 836	3 419	3 679	3 969	4 325	4 675	5 118
Surplus (Shortfall)	(535)	157	(45)	270	285	310	378	416	521

* If new power plants are not built according to the time schedule of PSMP, then the probability of shortfall will be more than that indicated above.

* Again, gas shortage will further deteriorate the power supply situation as shown above.

Notes:

<1 (a): Firm capacity = Generation capability – (1st largest + 2nd largest + largest GT unit capability) – Hydro constraints of 125 MW for low water level: up to fiscal year 2000.

(b): Firm capacity = Generation capability – (1st two largest units + largest GT unit capability) – Hydro constraints of 125 MW for low water level: from fiscal year 2001.

Figure X.1 Daily load curve of peak day

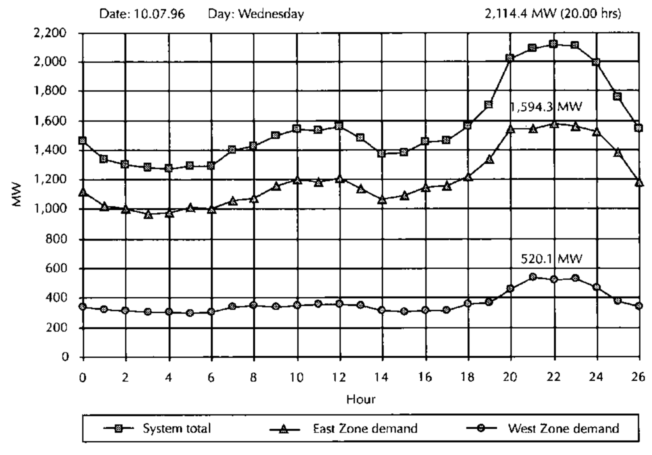


Figure X.2 Graphic presentation of gross generation pattern, fiscal year 1996

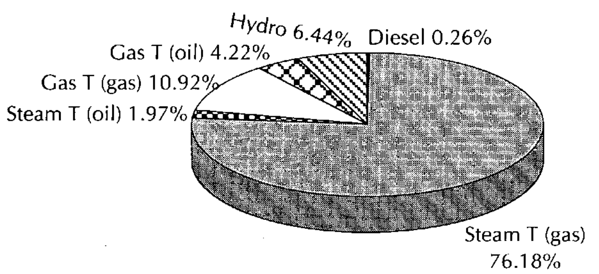


Figure X.3 Energy import by the three sectors of the net generation, fiscal year 1996

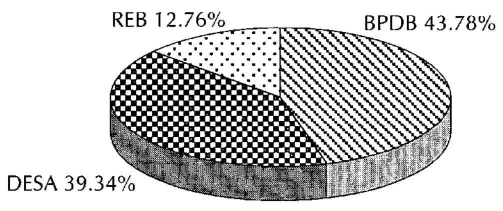
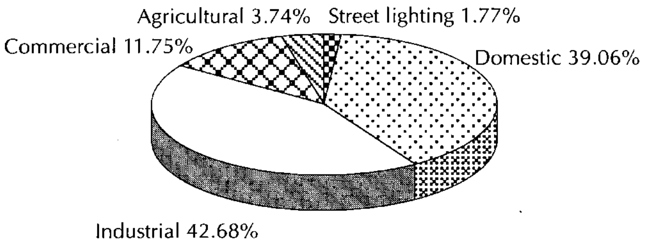


Figure X.4 Sectoral (BPDB + DESA + REB) electricity consumption, fiscal year 1996



In Bangladesh, there are 8 Nos. of 232/132 kV and 58 Nos. of 132/33 kV sub-stations (table X.4). Electricity is transmitted and distributed throughout the country and to DESA and REB through these sub-stations.

5. Principal energy resources

The principal sources of indigenous primary energy in Bangladesh are indigenous natural gas and coal. However, along with imported oil, owing to the limited hydro potential, mostly natural gas is in use as fuel for the generation of electricity.

(a) Natural gas and oil

Bangladesh's territorial boundary within the onshore and offshore totals about 207,000 km^2. Exploration activity in the eastern zone of Bangladesh has met with considerable success, while geophysical and geological activities in the western zone have not yet shown much success except in Bhola Island, in the south-western part. In spite of this good potential, Bangladesh remains relatively underexplored. Only 53 exploratory wells have been drilled since exploration commenced in 1910, an average of one well per 4,000 km^2. The impressive success rate of 1 in 3 overall since the beginning, resulted in the discovery of 12.4 Tcf of gas, 57 million barrels of condensate (gas liquid) and 6 million barrels of crude oil, which will be suspended in late 1997. The figures in table X.5 refer to proven recoverable reserve in producing fields with high degree of probability. In the opinion of some independent consultants, who studied the gas sector, the potential recoverable gas reserves are expected to be much higher than the current indicated figures. This viewpoint is reinforced by the number of major international exploration companies that have recently taken up exploration rights in the country on a production-sharing contract (PSC) basis. Some internationally reputed oil majors are expected to participate in the exploration and production of hydrocarbon through PSC.

(b) Gas production

Petrobangla is currently responsible for oil and gas production in Bangladesh. There are 7 producing and 10 non-producing gas fields in the country. The producing fields are Titas, Habiganj, Bakhrabad, Feni, Sylhet, Kailashtila and Rashidpur. Total gas production in 1993/94 averaged 613 mmcf/d or 223.8 Bcf for the year. Disaggregation by field is shown in table X.6.

Table X.3 Existing transmission lines

Sl. No.	*Name*	*Length (km)*	*Number of circuits*	*Conductor*	
				Name	*Size*
230 kV lines					
1.	East-West Electrical Interconnector	179	Double	Mallard	795 MCM
2.	Tongi-Ghorasal	27	Double	Mallard	795 MCM
3.	Ashuganj-Ghorasal	44	Double	Mallard	795 MCM
4.	Raujan-Hathazari	22	Single	Twin 300 sq m m	
5.	Ashuganj-Comilla North	79	Double	Finch	1 113 MCM
6.	Ghorasal-Haripur-Hasnabad	60	Double	Twin Mallard	
7.	Ishurdi-Bheramara	8	Double		
	Total	**419**			
132 kV lines					
1.	Siddhirganj-Shahjibazar	138	Double	Grosbeak	636 MCM
2.	Kaptai-Siddhirganj	273	Double	Grosbeak	636 MCM
3.	Kulshi-Halishahar	13	Single	Grosbeak	636 MCM
4.	Shahjibazar-Chhatak	150	Double	Grosbeak	636 MCM
5.	Comilla South-Chandpur	70	Single	Linnet + Grosbeak	336.4 + 636 MCM
6.	Comilla North-Comilla South	16	Double	Grosbeak	636 MCM
7.	Ashuganj-Jamalpur	166	Single	Grosbeak	636 MCM
8.	Madanhat-Sikalbaha	13	Double	Grosbeak	636 MCM
9.	Sikalbaha-Dohazari	35	Double	Grosbeak	636 MCM
10.	Sikalbaha-Halishahar	13	Single	AAAC	804 sq m m
11.	Tongi-Kabirpur-Tangail	73	Single	Grosbeak	636 MCM
12.	Kulshi-Baraulia	13	Single	Grosbeak	636 MCM
13.	Madanhat-Kulshi	13	Single	Grosbeak	636 MCM
14.	Madanhat-Kulshi	13	Single	Grosbeak	636 MCM
15.	Kaptai-Baroaulia	58	Double	Grosbeak	636 MCM
16.	Dohazari-Cox's Bazar	88	Single	Grosbeak	636 MCM
17.	Goalpara-Ishurdi	169	Double	HAWK	477 MCM
18.	Ishurdi-Bogra	106	Double	HAWK	477 MCM
19.	Bogra-Saidpur	140	Double	HAWK	477 MCM
20.	Saidpur-Thakurgaon	64	Double	HAWK	477 MCM
21.	Goalpara-Bagerhat-Barisal	109	Single	HAWK	477 MCM
22.	Bagerhat-Mongla	31	Single	HAWK	477 MCM
23.	Bheramara-Faridpur-Barisal	225	Double	HAWK	477 MCM
24.	Rajshahi-Natore	40	Single	HAWK	477 MCM
25.	Ishurdi-Shahjadpur	73	Single	Grosbeak	636 MCM
26.	Bogra-Shirajganj	66	Single	Grosbeak	636 MCM
27.	Shirajganj-Shahjadpur	34	Single	Grosbeak	636 MCM
28.	Rajshahi-Nawabganj	47	Double	Grosbeak	636 MCM
29.	Ishurdi-Pabna	16	Double	Grosbeak	636 MCM
30.	Pabna-Shahjadpur	40	Single	Grosbeak	636 MCM
31.	Feni-Chowmuhani	32	Single	Grosbeak	636 MCM
32.	Mymensingh-Nettrokona	34	Single	Grosbeak	636 MCM
33.	Kawkhali-Bhandaria	8	Single		
34.	Rangpur-Lalmonirhat	38	Single	Grosbeak	636 MCM
35.	Bogra-Noagaon	52	Double	Grosbeak	636 MCM
	Total	**2 469**			

Table X.4 Grid sub-stations of Bangladesh

Sl. No.	*Name*	*Voltage*	*Transformer capacity MVA*
230 KV GRID SUB-STATIONS OF BOTH ZONES			
1.	Ashuganj	230/132 kV	2 x 150
2.	Ghorasal	230/132 kV	2 x 125
3.	Ishurdi	220/132 kV	7 x 75*
4.	Tongi	230/132 kV	7 x 75*
5.	Comilla North	230/132 kV	3 x 75*
6.	Postogola	230/132 kV	6 x 75
7.	Hathazari	230/132 kV	2 x 150
8.	Haripur	230/132 kV	7 x 75*
132 KV GRID SUB-STATIONS OF EAST ZONE			
1.	Ashuganj	132/33 kV	2 x 15/25
2.	Baraulia	132/33 kV	1 x 28/40, 1 x 25/41.6
3.	Bangabhaban	132/33 kV	2 x 28/35
4.	Chandpur	132/33 kV	2 x 15/20
5.	Chandraghona	132/33 kV	2 x 10/13.3
6.	Chhatak	132/33 kV	1 x 10
7.	Comilla North	132/33 kV	1 x 40
8.	Comilla South	132/33 kV	2 x 25/41
9.	Cox's Bazar	132/33 kV	1 x 16/20
10.	Dhanmondi	132/33 kV	2 x 50/75
11.	Dohazari	132/33 kV	2 x 28/40
12.	Fenchuganj	132/11 kV	1 x 15/20
13.	Feni	132/33 kV	2 x 15/20
14.	Ghorasal	132/33 kV	2 x 50
15.	Halishahar	132/33 kV	1 x 25/41.6
		132/33 kV	2 x 44.1/63
16.	Hathazari	132/33 kV	1 x 44/63
17.	Jamalpur	132/33 kV	2 x 10/13.3
18.	Kabirpur	132/33 kV	2 x 25/41
19.	Kaptai	132/33 kV	1 x 15/20
20.	Kishoregonj	132/33 kV	2 x 10/13.3
21.	Kulsi	132/33 kV	2 x 44.1/63
22.	Madanhat	132/33 kV	2 x 25/41.7
23.	Mirpur	132/33 kV	3 x 35/50/55
24.	Mymensingh	132/33 kV	2 x 25/41
25.	Postagola	132/33 kV	3 x 35/50
26.	Shahjibajar	132/33 kV	1 x 15/20
27.	Shampur	132/33 kV	2 x 50/75
28.	Siddhirganj	132/33 kV	2 x 50/83.3
		132/11 kV	1 x 25/33
29.	Sikalbaha	132/33 kV	1 x 25/41
30.	Sreemongol	132/33 kV	1 x 10/12.5
		132/11 kV	1 x 7.5
31.	Sylhet	132/33 kV	2 x 15/20
32.	Tangail	132/33 kV	2 x 10/13.3
33.	Tongi	132/33 kV	1 x 50/75, 1 x 25/41.6
		132/33 kV	3 x 16.66/25 (1-phase)
34.	Ullon	132/33 kV	2 x 35/50
35.	Netrokona	132/33 kV	2 x 15/20
36.	Chowmuhoni	132/33 kV	2 x 25/41
132 KV GRID SUB-STATIONS OF WEST ZONE			
1.	Bagerhat	132/33 kV	2 x 10/13.3
2.	Barisal	132/33 kV	2 x 15/20
3.	Bheramara	132/11 kV	1 x 12.5/16.6
4.	Bogra	132/33 kV	2 x 25/41
5.	Bottail	132/33 kV	2 x 15/20
6.	Faridpur	132/33 kV	2 x 15/20
7.	Goalpara	132/33 kV	2 x 12.5/16.6
8.	Ishurdi	132/66 kV	2 x 12.5/16.6
		132/33 kV	2 x 15/20
9.	Jessore	132/33 kV	2 x 40
10.	Jhenaidah	132/33 kV	2 x 15/20
11.	Khulna central	132/33 kV	3 x 48/64
12.	Madaripur	132/33 kV	2 x 10/13.3
13.	Mangla	132/33 kV	1 x 10/13.3
14.	Natore	132/33 kV	1 x 15/20
15.	Noapara	132/33 kV	1 x 10/13.3
16.	Palashbari	132/33 kV	2 x 10/13.3
17.	Purbasadipur	132/33 kV	2 x 12.5/16.6
18.	Rajshahi	132/33 kV	1 x 25/33, 1 x 15/20
19.	Rangpur	132/33 kV	2 x 15/20
20.	Saidpur	132/33 kV	1 x 15/20
		132/33 kV	1 x 10/13.3
21.	Shahjadpur	132/33 kV	1 x 15/20
		132/66 kV	1 x 15/20
22.	Thakurgaon	132/33 kV	1 x 12.5/16.6
			1 x 10/13.3
			1 x 15/20
23.	Pabna	132/33 kV	1 x 25/41
24.	Nawabganj	132/33 kV	2 x 15/20
25.	Serajganj	132/33 kV	2 x 15/20
26.	Lalmonirhat	132/33 kV	2 x 15/20
27.	Naogaon	132/33 kV	1 x 25/41

* Transformers are single phase with one no. spare.

Table X.5 Bangladesh – gas and oil reserves, August 1994

Field	*Date*	*Proven (recoverable) reserves of natural gas (Tcf)*			*Proven (recoverable) reserves of condensate (mmbbls)*		
		Original	*Cumulative*	*Net recoverable*	*Original*	*Cumulative*	*Net recoverable*
Bakhrabad	1969	0.87	0.38	0.49	2.13	0.60	1.53
Chhatak	1959	1.14	0.03	1.11	0.08	0.00	0.08
Habiganj	1963	1.90	0.43	1.47	0.10	0.02	0.08
Kamta	1981	0.19	0.02	0.17	0.04		0.04
Kailas Tila	1962	2.53	0.07	2.46	27.56	0.70	26.86
Feni	1981	0.08	0.02	0.06	0.24	0.04	0.20
Sylhet	1955	0.26	0.15	0.11	0.89	0.53	0.36
Titas	1962	2.10	1.10	1.00	3.02	1.50	1.52
Begumganj	1977	0.02		0.02	0.01		0.01
Beanibazar	1981	0.11		0.11	1.82		1.82
Belabo	1990	0.13		0.13	0.31		0.31
Fenchuganj	1988	0.21		0.21	0.52		0.52
Jalalabad	1989	0.90		0.90	15.75		15.75
Kutubdia	1977	0.47		0.47			
Meghna	1990	0.10		0.10	0.21		0.21
Rashidpur	1960	1.31	0.03	1.28	4.00		4.00
Semutang	1969	0.10		0.10	0.02		0.02
Total		12.42	2.23	10.19	56.70	3.39	53.31
Crude oil (mmbbls)							
Sylhet (Haripur)	1986				6.00	0.57	5.43
Total liquids					62.70	3.96	58.74

Table X.6 Natural gas production, fiscal year 1994

Field	*mmcf/d*	*Bcf/year*
Titas	268.00	97.70
Bakhrabad	130.00	47.40
Habiganj	136.00	49.80
Feni	15.00	5.60
Sylhet	4.00	1.30
Kailastila	27.00	10.00
Rashidpur	33.00	12.00
Total	**613.00**	**223.80**

Table X.7 Consumption of natural gas by sector, fiscal year 1994

Sector	*Bcf/year*	*mmcf/d*	*Percentage share*
Power	97.30	266.00	46.30
Fertilizer	74.50	204.00	35.40
Industry	18.50	51.00	8.80
Commercial	2.90	8.00	1.40
Domestic	15.40	42.00	7.30
Tea estates	0.70	2.00	0.30
Brick fields	1.00	3.00	0.50
Total	**210.30**	**576.00**	**100.00**

(c) Gas consumption

Total consumption of natural gas in fiscal year 1994 was 210 Bcf. In fiscal year 1989 it was 146 Bcf, which represents an average compound growth rate of 7.5 per cent per annum. Consumption of natural gas by different sectors is shown in table X.7. As indicated, the power sector is the major consumer, with 46 per cent of total consumption, while fertilizer is second at 35 per cent.

(d) Issues related to gas for power generation

According to the Power System Master Plan prepared for the plan period 1995-2015, the total cumulative natural gas consumed over the 20-year period would be 4.5 Tcf. Table X.8 is an illustration of the total reserves of natural gas which would be consumed in a relatively high growth rate. The present consumption of natural gas in power generation is

Table X.8 Natural gas requirement for power generation (approximate)

Year	Average load (MW)	Natural gas requirement		
		MMCFD	BCF/YEAR	CUM BCF
1	1 600	262	96	96
2	1 728	283	103	199
3	1 866	306	112	310
4	2 016	330	120	431
5	2 177	356	130	561
6	2 351	385	141	702
7	2 539	416	152	853
8	2 742	449	164	1 017
9	2 961	485	177	1 194
10	3 198	524	191	1 385
11	3 454	566	206	1 592
12	3 731	611	223	1 815
13	4 029	660	241	2 056
14	4 351	713	260	2 316
15	4 700	770	281	2 597
16	5 075	831	303	2 900
17	5 482	898	328	3 228
18	5 920	970	354	3 582
19	6 394	1 047	382	3 964
20	6 905	1 131	413	4 377

Assumptions:

Starting average load	1,600	MW
Growth per year	8.0	per cent
Planning horizon	20	years
Average efficiency	30.0	per cent
Average annual plant factor	60.0	per cent

approximately 100 Bcf/year, or roughly the equivalent of an average power load of 1,600 MW operating at 60 per cent annual capacity factor and 30 per cent efficiency (purely for illustrative purposes). If the annual growth rate of the load is 8 per cent compounded over 20 years, this would result in an average load on the gas system of about 7,150 MW by 2015 consuming 4.5 Tcf of gas cumulatively. This is very close to the 50 per cent share of the present remaining proven recoverable reserves of 10.2 Tcf.

The relatively attractive prospect for the remaining unexplored blocks as evidenced by the high success rate of previous exploration would indicate that additional reserves are likely to be found. It appears that these would probably at least equal the existing known resource base. As a rough measure of adequacy of resource base, one needs to know the reserve life. This is defined as the total remaining proven, recoverable reserves divided by the current production. In the case of Bangladesh, the reserves of 10.2 Tcf divided by 0.224 Tcf/year, gives a reserve life of 46 years. While this may be a mere approximation, in a highly prospective gas area, it is most likely that there will be additions to existing reserves as exploration proceeds. In many countries, including Canada, reserves have been continually added at a faster rate than depletion as a result of new discoveries, in spite of very high production in the interim.

Therefore, it appears that Bangladesh does not suffer from natural gas scarcity in terms of the needs of the overall economy. The problem is a chronic one of shortfall in deliverability infrastructure, i.e. field development, transmission and distribution pipelines and facilities. Severe load shedding is currently done due to this limitation in infrastructure. The long-awaited Ashuganj-Bakhrabad gas pipeline connecting Titas gas system with that of Bakhrabad was completed in May 1997, which would ease the current gas supply for the generation of power.

(e) Coal resource

Coal mining from a field known as Barapukuria has recently been initiated. A plan is under way to utilize more than 80 per cent of coal produced from Barapukuria for the generation of electricity, hopefully by the year 2000. Nevertheless, as a result of much painstaking work over the years, there are now signs that coal may become a modest national resource. The Geological Survey of Bangladesh (GSB) has the responsibility for locating the coal resources present in Bangladesh. The development of coal resources identified is to be undertaken by the Bangladesh Oil, Gas and Mineral Corporation (BOGMC). Coal resources estimated at 1,782 million tons have been discovered in three locations in the north-west of the country, Jamalganj in Bogra District, Barapukuria in Dinajpur District and Khalaspir in Rangpur District.

Barapukuria. Discovered by the Geological Survey of Bangladesh in 1985, it has six coal seams with a total thickness exceeding 50 m at a depth ranging from 70 m to 506 m over 5.25 km^2 area. The reserve in three principal seams amounts to 303 Mt, as shown in table X.9. Additional reserves are thought to exist in an unproven southernly extension with an area of 1 to 1.5 km^2. Table X.10 provides details concerning the quality of this coal. A Chinese Mining Consortium (CMC) has been awarded the contract to develop the mine on a supplier's credit basis. Sample

Table X.9 Barapukuria – estimated coal reserves

Seam	*Seam thickness (m)*		*Reserves (Mt)*	
	Range	*Average*	*Demon-strated*	*Inferred*
I	–	–	–	1
II	7 to 9	8	14	–
III	–	–	–	4
IV	3 to 8	6	18	–
V	–	–	–	17
VI	29 to 42	36	271	43 to 64
Total	**–**	**50**	**303**	**65 to 86**

Table X.10 Barapukuria – seam VI coal quality

Characteristic	*Full seam (As-received basis)*	*Mined section (Wardell)*
Moisture, %	10.00	10.00
Ash, %	16.20	12.40
Volatile matter, %	27.60	29.20
Fixed carbon, %	46.40	48.40
Sulphur, %	0.57	0.53
Gross heat value, kJ/kg	24 310.00	25 680.00
Gross heat value, Btu/lb	10 450.00	11 040.00

Source: Wardell Armstrong.

coal production has already started with the first significant coal production scheduled to start in June 1999 having the target output of 1 Mt/year achieved during 2001. Based on this mine, a coal-based power station of 300 MW (2 x 150 MW) has been planned. This power station is going to be constructed on supplier's credit basis. Tenders for this power station have been received and are now under evaluation.

Jamalganj. In 1961, while drilling 10 holes, seven coal seams with a total thickness of 63 m were encountered at depths between 640 m and 1,158 m. Different feasibility studies agreed that there was significant resource of coal, which would support a production of at least 1 Mt/year for 50 years, but there were major differences in the methods and cost of developing the mine, mainly due to the depth of the seams.

Khalaspir. In 1989/90, the Geological Survey of Bangladesh confirmed the presence of coal when four holes were drilled. The coal deposit lies at depths ranging from 257 m to 483 m in eight zones. The coal beds range in thickness from a few centimetres to 14 m. There could be large vertical and lateral variations to the coal seams, but data are limited.

Others. There are other potential areas in Dinajpur, Rangpur and Sylhet Districts where coal can be found. GSB will drill each area as funds allow. An output of 4 to 6 Mt/year from these underground mines within 20 years is not beyond the realm of possibility. With a successful surface mine, total output potential may be 10 Mt/year.

(f) Renewable energy options

In Bangladesh, renewable energy sources are limited. These includes hydropower (reservoir storage, run-of-river, pump storage), wind power, solar power, biomass, geothermal and energy from waste.

Hydropower

Bangladesh has abundant rainfall and large rivers. Despite this fact, the hydropower potential is very limited. In Chittagong Hill Tracts (in the south-east), 230 MW of hydropower station was established in the early 1960s at Kaptai based on a large storage reservoir. There is an additional potential of 250 MW at Sangu and Matamuhari, but the cost in terms of environmental and social impact for the new storage reservoir will be very high. None of these sites is socially desirable. Other major rivers, being located in flat land, have a low gradient. Therefore, they offer least potential for hydropower, unless a technological breakthrough in this sector can be experimented upon.

Wind power

In parts of Bangladesh, wind power could offer some potential, but this would not be likely to account for a significant amount of base load. Wind power could be used to service areas that are expensive to reach with HV transmission lines (e.g. coastal areas, islands and hilly areas). The design would have to consider the variability in wind conditions from calm to cyclones. This would make some designs uneconomical for Bangladesh. In rural areas, small wind generators could be used to power shallow tube wells.

Solar power

Solar power is gaining more acceptance on a small scale. Generally it is still expensive in terms of the initial investment costs. Solar power can sometimes be competitive to displace small high-unit-cost diesel generating units. Most of Bangladesh is not well suited for solar power, because in the monsoon season the cloud cover is extremely dense for a large percentage of daylight hours. However, REB has introduced solar energy in its Narasingdi PBS on a pilot basis.

Biomass

Although there are few forests left in Bangladesh, there is an abundance of biomass generated on farms. Most of the rural population still depends on biomass for the majority of their daily energy needs. Biomass utilization includes rice husks (26 per cent); cow dung (19 per cent); rice straw (16 per cent); twigs and leaves (14 per cent); bagasse (7 per cent); fuelwood (5 per cent) and jute sticks (4 per cent). Traditionally, much of the grass, straw and dung is utilized for fertilizer, animal feed, house construction and handicrafts. Preservation of forests has limited the amount of fuelwood available, resulting in greater consumption of cow dung for energy rather than manure. There needs to be a reasonable balance between agricultural, energy and environmental needs. Today, some man-made products are displacing biomass (for fertilizer or building materials), and there could be potential for harnessing biogas production on small and medium scales. Typically, biogas is used as a cooking fuel, and therefore it displaces kerosene or wood rather than electricity. Water hyacinth is to be found extensively and could possibly serve as a source of biogas.

Energy from waste

In urban centres, there is a large problem of waste disposal. These sites use up valuable land and cause serious health problems. This situation will only be compounded in the future. Energy from waste is a proven technology. The major cost factor is the collection and processing of waste materials. Given the labour costs in Bangladesh, this should provide an economic advantage. Much of the waste is informally sorted in search of reusable materials. Even after this process, the amount of waste is enormous and could be utilized for energy if properly organized. New designs for waste incinerators are improving the feasibility of schemes for developing countries. The benefits from power generation and urban waste clean-up would be long-lasting.

Geothermal resources

Bangladesh does not possess any geothermal resources. Estimates of energy supplied by traditional fuels and final consumption of commercial energy by sector are shown in tables X.11 and X.12.

Table X.11 Estimates of energy supplied by traditional fuels

(Thousands of tons of coal equivalent)

Year	*Fuel ->*	*Cowdung*	*Jute stick*	*Rice straw*	*Rice hulls*	*Bagasse*	*Firewood*	*Twigs and leaves*	*Other wastes*	*Total*
1988/89		1 927	570	1 539	2 022	602	475	1 270	1 056	9 461
1989/90		1 866	396	1 535	2 591	653	425	1 325	1 096	9 887
1990/91		1 898	439	1 492	2 592	679	475	1 325	1 096	9 996
1991/92		1 989	395	1 448	2 679	654	529	1 325	1 053	10 072
1992/93		2 018	439	1 405	2 722	679	539	1 325	1 096	10 223

Note: One ton (metric ton) of coal is equivalent to 27.55 x 10^6 Btu.

Table X.12 Final consumption of commercial energy by sector

(Thousands of tons of coal equivalent)

Year	*Sector ->*	*Domestic/ residential*	*Industrial*	*Commercial/ service*	*Transport*	*Others and agriculture*	*Non-energy use*	*Total final consumption*
1988/89		789	908	175	601	376	1 394	4 243
1889/90		831	1 275	151	637	306	1 472	4 672
1990/91		777	920	119	777	277	1 412	4 282
1991/92		749	1 029	111	790	311	1 512	4 502
1992/93		903	836	134	970	275	1 801	4 919

Notes: Commercial energy includes natural gas, petroleum products, coal and electricity.
Final consumption excludes intermediate consumption.
Non-energy use indicates use of natural gas as raw material in fertilizer factories.
One ton (metric ton) of coal is equivalent to 27.55 x 10^6 Btu.

C. ENERGY PRICING

1. The need for tariff changes

There is no doubt that a reliable and economical electricity supply plays an important role in a country's development. Yet the investments required are costly and have a high foreign exchange content. Tariffs for electricity must reflect these costs or a serious misallocation of resources is likely to occur; thus, when prices are too low, demand, and hence investment, will be over-expanded relative to other important development expenditure.

Unlike many commodities, electricity cannot be stored and must be generated instantaneously to meet demand. The level of investment in new generating capacity, and for much of the transmission and distribution capacity, is therefore determined by demand at peak times when many consumers wish to use their supplies. If such consumers are not charged according to the cost they impose on the system, there is a danger of the nation devoting too much of its resources to provide capacity which is only needed for a few hours every day. Alternatively, if the investment is not made, the level of system reliability falls and all consumers suffer irrespective of their willingness to pay for a secure supply.

2. Ad hoc tariff increase

Pricing of electricity in Bangladesh is currently based more on political considerations than on economic viability. In the present system, the utility does not fix the price on a long-run marginal cost basis, but it is decided by the Government and the utility is asked to implement it. Recently, of course, under pressure from the donor agencies the need to restructure the tariff was felt by the Government and as an interim measure an average rise of 15 per cent in the tariff was allowed in two phases. The first phase, a 10 per cent rise, was effected from 1 October 1996 and the second phase, a 5 per cent rise came into effect from 1 December 1996, except for irrigation consumers. Again, on 1 March 1997, a lump-sum rise of Tk 0.05 per kWh was allowed to compensate the fluctuation of the Tk – dollar exchange rate. In the meantime, a consultant was engaged in May 1996 by the World Bank to study the tariff structure as a part of its overall study on power sector reform. The consultant has finalized the study and the draft final report has been submitted.

3. Present tariff structure

The present tariff structure of BPDB, by category, is shown table X.13. This tariff structure has no relationship with the cost of production, let alone the rate of return. The long-run marginal cost at the 440-volt level as estimated by the consultant should be Tk 3.77 per kWh (8.56 cents) whereas the BPDB billing rate for fiscal year 1997 is Tk 1.94. The long-run marginal cost for BPDB and DESA is shown in table X.14.

4. Scale of consumer subsidies

At the existing tariff rates which are set below the economic cost level the consumers (except LV commercial consumers) receive subsidies. An analysis by the consultants (M/s. London Economics) made in December 1996 showed that domestic tariffs need to more than double to reach economic levels. The total estimated (economic) subsidies received by domestic consumer, by utility, are given in table X.15A. It shows that the total subsidies received by domestic consumer each year is estimated to be Tk 7,217 million, with Tk 2,776 million being received by consumers served by BPDB, Tk 3,262 million by consumers served by DESA and Tk 1,179 million by consumers served by the PBSs of REB. Subsidies given to other categories of consumers are shown in tables X.15B-X.15G.

5. Tariff on the basis of long-run marginal cost

M/s. London Economics, the consultants engaged for the tariff study, presented estimates for long-run marginal costs of generation, transmission and distribution. On this basis they made recommendations for both final retail tariffs and transfer charges at the level of generation and transmission. They also recommended a transition path towards the proposed reform which took into account the overall programme for power sector reform.

The recommended bulk supply charges are as follows: (a) transmission charge – Tk 920/kW, (b) peak generation charge – Tk 3,428.00/kW, (c) 1st TOD charge (2300 to 0600 hrs.) – Tk 1.60/kWh, (d) 2nd TOD charge (0600 to 1300 hrs.) – Tk 1.65/kWh, (e) 3rd TOD charge (1300 to 1700 hrs.) – Tk 1.62/kWh and (f) 4th TOD charge (1700 to 2300 hrs.) – Tk 2.10/

Table X.13 Existing tariff structure of BPDB

Category of consumer	*Existing charging basis*	*Existing tariff (Effective 1 March 1997)*
A. Residential light and power (0.23/0.4 kV)	Energy charge:	
	0-300 kWh	Tk 1.85
	301-500 kWh	Tk 3.00
	501-700 kWh	Tk 4.05
	Above 700 kWh	Tk 5.25
	Demand charge:	Tk 10.00/kW/month
	Service charge:	
	Single phase	Tk 5.00/month
	Three phase	Tk 25.00/month
	Minimum charge:	Tk 100.00/month
	Government duty:	Tk 0.15/kWh
B. Agricultural pumping (0.23/0.4 kV)	Energy charge	Tk 1.75/kWh
	Demand charge: (>30 kW)	Tk 35.00/kW/month
	Service charge:	Tk 25.00/month
	Minimum charge:	Tk 125.00/HP/month
	Government duty:	Tk 0.15/kWh
C. Small industrial (0.23/0.4 kV)	Energy charge:	
	Flat	Tk 3.20/kWh
	Off-peak	Tk 2.45/kWh
	Peak	Tk 4.65/kWh
	Demand charge: (>40 kW)	Tk 35.00/kW/month
	Service charge:	Tk 60.00/month
	Minimum charge:	..
	Government duty:	Tk 0.15/kWh
D. Non-residential light and power (0.23/0.4 kV)	Energy charge:	Tk 2.60/kWh
	Demand charge:	Tk 15.00/kW/month
	Service charge:	
	Single phase	Tk 5.00/month
	Three phase	Tk 25.00/month
	Minimum charge:	Tk 100.00/kW/month
	Government duty:	Tk 0.15/kWh
E. Commercial (0.23/0.4 kV)	Energy charge:	
	Flat	Tk 4.35/kWh
	Off-peak	Tk 3.00/kWh
	Peak	Tk 7.00/kWh
	Demand charge:	Tk 20.00/kW/month
E Commercial (0.23/0.4 kV)	Service charge:	
	Single phase	Tk 5.00/month
	Three phase	Tk 25.00/month
	Minimum charge:	Tk 125.00/kW/month
	Government duty:	Tk 0.15/kWh
F. Medium-voltage general purpose (11 kV)	Energy charge:	
	Flat	Tk 3.00/kWh
	Off-peak	Tk 2.40/kWh
	Peak	Tk 5.65/kWh
	Demand charge:	Tk 40.00/month
	Service charge:	Tk 350.00/month
	Minimum charge:	Tk 80.00/kW/month (But not less than Tk 8,000/month)
	Government duty:	Tk 0.15/kWh
G. DESA (132 kV)	Energy charge:	Tk 1.66/kWh
H. High-voltage general purpose (33 kV)	Energy charge:	
	Flat	Tk 2.80/kWh
	Off-peak	Tk 2.30/kWh
	Peak	Tk 5.40/kWh
	Demand charge:	Tk 35.00/month
	Service charge:	Tk 400.00/month
	Minimum charge:	Tk 80.00/kW/month
	Government duty:	Tk 0.15/kWh
I. High-voltage bulk supply to PBSs (33 kV & 11 kV)	Energy charge:	Tk 1.59/kWh
	Demand charge:	..
	Service charge:	Tk 400.00/month
	Minimum charge:	..
	Government duty:	..
J. Street lighting and water pumps (0.23/0.4 kV)	Energy charge:	Tk. 3.05/kWh
	Demand charge:	Tk 35.00/kW/month
	Service charge:	Tk 200.00/month
	Minimum charge:	..
	Government duty:	Tk 0.15/kWh

Table X.14 Long-run marginal costs: BPDB and DESA
(PBSs in parentheses)

(Cents/kWh, 1996 prices and 12% discount rate)

	Generation	*132 kV*	*33 kV*	*11 kV*	*440 V*	*Total*
Generation	4.62					4.62
Percentage losses	3.03%					
132 kV	4.76	0.50				5.26
Percentage losses	3.09%	3.09%				
33 kV	4.91	0.52	0.63			6.05
			(0.38)			(5.80)
Percentage losses	3.04%	3.04%	3.04%			
11 kV	5.06	0.53	0.65	1.06		7.30
			(0.39)	(1.26)		(7.24)
Percentage losses	4.81%	4.81%	4.81%	4.81%		
440 V	5.30	0.56	0.68	1.11	0.91	8.56
			(0.41)	(1.32)	(1.05)	(8.64)
Total	5.30	0.56	0.68	1.11	0.91	8.56
			(0.41)	(1.32)	(1.05)	(8.64)

kWh. In addition, charges for the use of the system have been recommended as (a) 132 kV use-of-system – Tk 522.00/kW and (b) 33 kV use-of-system – Tk 842.00/kW for DESA.

For domestic consumers, the average economic cost of delivered energy has been calculated by M/s. London Economics as Tk 4.58/kWh.

The recommended tariffs for other groups are small industrial – Tk 4.07, and agricultural – Tk 3.98 as against the present average tariff of Tk 2.36*. This is an increase of 69 per cent over the existing average tariff. The consultant has proposed increasing the tariff in phases over three years i.e. in 1997, 1998 and 1999. This implies that in the current year 12 to 31 per cent increases for different groups are to be made effective.

A new tariff for prepaid meter (residential) has been proposed at a flat charge of Tk 4.6/kWh. Two blocks for domestic consumers have been proposed, first up to 150 kWh at a rate of 3.5/kWh, and second above 150 kWh at a rate of Tk 4.60/kWh. All categories of consumers have to pay a standing charge of Tk 23.00 in addition to the above tariff.

6. Impact of tariff reform on government finances

The success of the Independent Power Producers programme depends on the ability of the sector to deliver revenues to the new power station owners. This means that the tariff must be overall-cost reflective and revenue collection must be improved. Otherwise an increasingly difficult financial burden will fall on to the government.

The phasing of the proposed tariff increase is shown in table X.16. If this can be implemented, the impact on the government finances will be positive, as shown in table X.17. Current non-collection rates are around 20 per cent. The indicative changes in the collection rates are based on the introduction of proposed strategic reform and on the introduction of prepayment meters, both of which would serve to reduce non-collection loss.

The increase in tariff levels is sufficient to move BPDB and DESA into profit by 1997/98. The combined losses of BPDB and DESA in 1996/97 are Tk 5.525 million compared with Tk 10,754 million with no tariff increase. By 1999/2000, after the completion of the tariff increase programme, BPDB and DESA would be making a combined profit of Tk 14,546 million (table X.18).

D. STRUCTURAL REFORM OF THE ENERGY SECTOR

The present government-controlled structure of the power sector has not been able to deliver in accordance with the country's growing needs. It now faces a major challenge of improving low coverage, bad quality and poor reliability.

* Average billing rate of all the total end consumers of BPDB and DESA.

Table X.15 Economic costs versus tariffs

	Average unified economic cost (Tk/kWh)	*Average bill subject to scheduled tariff rise (Tk/kWh)*	*Economic subsidy (Tk/kWh)*	*Economic subsidy as a percentage of average bill*	*Total economic subsidy (MTk)*
A. Domestic consumers					
BPDB	4.58	2.01	2.57	128%	2 776
DESA	4.58	1.93	2.65	137%	3 262
PBSs	5.12	2.29	2.83	124%	1 179
Total					**7 217**
B. LV commercial					
BPDB	3.95	4.35	-0.40	-9%	-125
DESA	3.95	4.07	-0.12	-3%	-24
PBSs	4.39	4.51	-0.12	-3%	-8
Total					**-157**
C. LV industrial consumers					
BPDB	4.07	2.95	1.12	38%	422
DESA	4.07	2.79	1.27	46%	425
PBSs	4.53	4.44	0.09	2%	39
Total					**886**
D. Agricultural consumers					
BPDB	3.79	1.88	1.91	102%	277
DESA	3.79	1.67	2.12	127%	33
PBSs	4.21	2.34	1.87	80%	452
Total					**762**
E. Streetlighting consumption					
BPDB	4.62	3.03	1.59	52%	93
DESA	4.62	2.87	1.75	61%	52
PBSs	5.17	3.89	1.28	33%	3
Total					**148**
F. 11-kV consumers					
BPDB	3.26	2.61	0.65	25%	562
DESA	3.26	2.38	0.88	37%	805
PBSs	3.30	2.92	0.38	13%	N/A
Total					**1 367**
G. 33-kV consumers					
BPDB	2.79	2.14	0.65	30%	101
DESA	2.79	2.06	0.73	35%	34
PBSs	2.72	3.30	-0.58	-18%	N/A
Total					**135**

Table X.16 Phasing real tariff increases

Consumers	*Average price, 1996*	*1997 percentage increase*	*1998 percentage increase*	*1999 percentage increase*	*Economic price*
Domestic	2.01	32%	32%	32%	4.58
Small industrial	2.95	19%	10%	6%	4.07
Agricultural	1.88	26%	26%	26%	3.79
11 kV	2.61	12%	7%	4%	3.26
33 kV	2.14	15%	8%	5%	2.79
Average	2.36	23%	18%	16%	3.98

Table X.17 Three-year phasing: impact of tariff reform on government finances

	1997	*1998*	*1999*	*2000*
Average price per kWh	2.36	3.18	3.67	4.00
Sales GWh	15 085	16 524	18 113	19 869
Maximum duties on sales (millions of taka)	2 263	2 479	2 717	2 980
Collection %	80%	80%	90%	100%
Possible revenue from duties (millions of taka)	1 810	1 983	2 445	2 980

Table X.18 Financial losses (accounting basis) with tariff increases
(Millions of taka)

	1996-1997	*1997-1998*	*1998-1999*	*1999-2000*
BPDB	-1 502	5 461	12 616	14 733
DESA	-4 023	-2 970	-676	-187

Figure X.5 Investment required for the power sector (from Power System Master Plan)

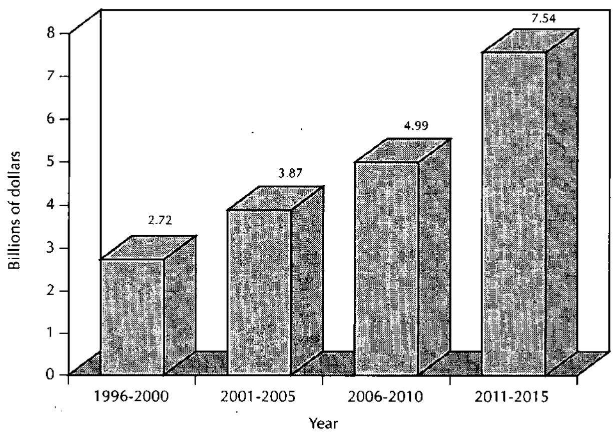


Figure X.6 Comparison of peak demand with capacity (from PSMP)

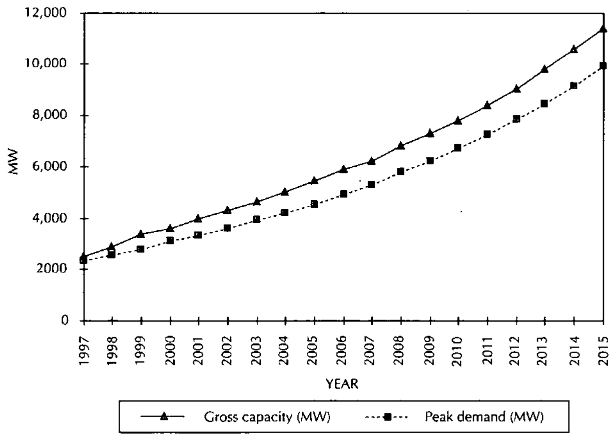
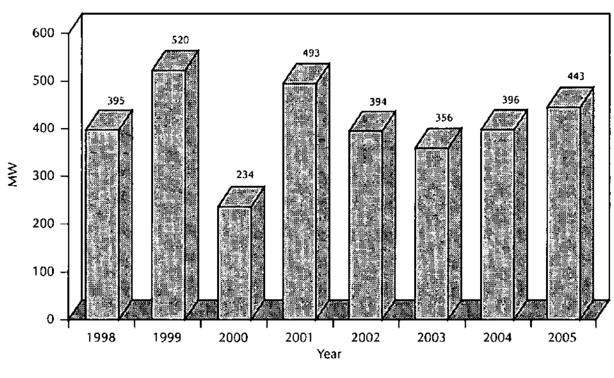


Figure X.7 Capacity addition up to 2005 (from PSMP)



The sector needs to mobilize around $6.6 billion in funds over the next decade to build up the energy infrastructure (figures X.5, X.6 and X.7). Traditional sources of investment funds will be insufficient. Major sector reform and increased private participation will be needed to mobilize this investment.

The Government of Bangladesh has agreed to a broad framework for reform and started work on mobilizing private investment in generation. To this end, it adopted the National Energy Policy and Private

Sector Power Generation Policy in 1996. The necessary amendments to the Presidential Order of 1972, by which BPDB was created, are being made to facilitate independent power producers (IPPs) coming in and selling their power to the utilities. Requests for proposals to establish three barge-mounted power plants of 100 MW capacity each were floated and received in January 1997. Two more requests, one for 300 MW at Meghnaghat and another for 300 MW at Haripur, have been floated. Evaluation of the proposals for barge-mounted power plants was completed in March 1997 and negotiations are now at the final stage. A power purchase agreement was initialled between BPDB and M/s. Enron International on 22 May 1997. The first IPP in Bangladesh is now expected to go into operation by June 1998.

1. Existing structure

The present structure of the power sector (figure X.8) is a large integrated generation, transmission and distribution business (BPDB); a large rapidly growing distribution business (DESA) and 45 rural electrification cooperatives (known as PBS) under REB. BPDB and DESA are characterized by over-staffing, inefficiency, lack of accountability and frequent excess in trade unionism. Although the situation in BPDB improved a little with the introduction of the Punishment and Reward Scheme, a sustained and appreciable improvement in efficiency has not been achieved up to now. Against this background, and with a view to attracting private investment, the Government has taken up different measures to reorganize the power sector structure. M/s. London Economics was engaged, among other things, to study and recommend a suitable structure for the power sector. The consultant has submitted a final report, which is now under consideration by the Government. Figure X.9 shows the emerging structure of the power sector.

Figure X.8 Existing structure of the power sector

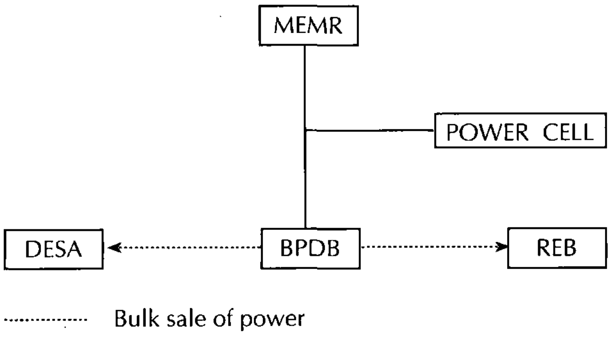
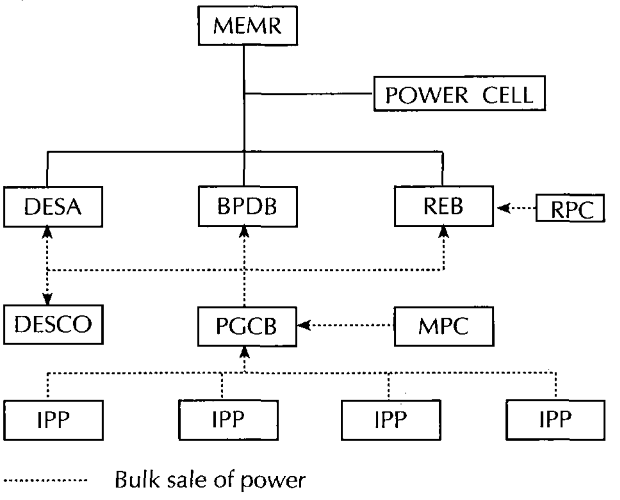


Figure X.9 Emerging structure of the power sector



2. Recommended future structure

The report of M/s. London Economics recommended separation of the generation, transmission and distribution business, which is currently being carried out by BPDB. It envisaged five medium-sized distribution businesses in Dhaka and BPDB's four zones, continuation of the PBS structure as a separate distribution business and separate profit centres for each of BPDB's generation plants. According to the consultant, all the BPDB generation profit centres should be under contract to a single buyer, initially located within the Power Grid Company of Bangladesh (PGCB). This body should pass through contract energy charges, plus regulated transmission charges, to distribution businesses within BPDB, DESA and PBSs. IPP investors should also contract with this body, but should also be free to contract directly with major industrial consumers. Scope should be maintained for changing the bulk generation market in some years time, when conditions permit.

For private sector participation, it was recommended that private finance should be used for new generation and transmission links. Contracts, they argued, would be used for rehabilitation of generation and to develop private sector participation in distribution. They opined that once confidence was established, and other necessary conditions were met, trade sales of distribution and generation businesses could also be considered.

M/s. London Economics recommended the creation of a regulatory office under new legislation.

The Act would describe the procedure for appointment and removal of the Regulator(s) and tenure of office. The proposed Act would describe duties, authorities and obligations of the Regulation(s) which, among others, would include licensable activities related to generation, transmission, distribution and supply. The Act would provide power to the Regulator to make subordinate regulations relating to the power sector. It would empower the Regulator/Ministry to enter into contract with licensees so as to provide a legal basis for commitments that may be necessary to encourage private sector investment, e.g. guarantees of payment obligations, implementation agreement and the like.

The licences given by the Regulator would be supported by a number of codes, which would include a Grid Code, a Distribution Code, a Planning Code and a Competitive Tendering Code. Contracts would be framed to document commercial bargains between licensees or other sector participants.

The regulatory body has been conceived to cover both the electricity and the gas sectors. The Regulatory Commission would consist of three members to be appointed by the President, subject to the approval of the Parliament, for a term of five years. The Commission would have a full-time staff of around 150 and a budget of at least $1.5 million to be financed through a levy on the electricity and gas. The Regulatory Commission would not set tariffs; it would set allowable charges per kWh and the principles on which tariffs should be based.

3. Observation on the recommended structure

Most of the recommendations of the consultant, such as the separation of transmission (creation of PGCB, to begin with), private participation in new generation (BMPP, MPC, RPC, etc.), and separate distribution business (creation of DESCO) have already been brought under implementation. It is understood that the ultimate aim of the reform is to improve the service to the consumer, in a qualitative and quantitative manner. Essentially, it must ensure that the growing demand for electricity is met i.e. the concerned authority, especially the distribution units, should be able to deliver according to the expectation of the end-users.

In the proposed structural reform, more emphasis has been given to the generation and transmission side, where BPDB is experiencing fewer problems. The most problematic areas for BPDB are the distribution zones. The age-old, overloaded distribution network, unplanned and under specified lines drawn on consideration of the political or social point of view rather than on economic viability, lack of maintenance owing to shortage of materials, undisciplined behaviour and undue pressure of the workers' union, inability of the management to bring the culprits to book due to union's activity, lack of political firm commitment to bring back order, unholy alliance between a section of the employees and consumers, etc. have made the distribution zones inefficient and unable to deliver. The proposed reform of mere separating out the distribution business in five areas will not cure the above ills responsible for mismanagement. This is evident from the example set out by DESA, which was separated out for the purpose of better management and efficiency. Attainment of these expressed goals by DESA remains a far cry even after five years of its creation. It appears that M/s. London Economics have not properly understood the field situation in the distribution area and in their recommendation these problems have not been duly addressed.

The proposal of PGCB as single buyer of power from the generating units and then delivering it to different distribution companies may lead to a situation of PGCBs becoming bankrupt owing to non-payment of energy bills by the distribution companies. At present DESA is buying power in bulk from BPDB, but is unable to pay BPDB in full. Huge amounts of money have been accumulated as arrears. Similarly, BPDB itself has failed to recover arrear bills from most of the government agencies and some of the private consumers. Neither BPDB nor DESA can disconnect defaulting government departments. In the new situation, the distribution companies will be in the same position of being unable to snap the lines of government/semi-government/autonomous offices. They will, thus, be defaulters in paying to PGCB, which will be under a contractual obligation to pay the generator in time every month. Instead of making PGCB a single buyer, the generators should be able to sell power to any distribution company at competitive prices using PGCB as "wheeler" of power. PGCB can collect wheeling charges to be determined on the basis of operation and maintenance costs with a reasonable return on their investment.

PGCB was incorporated as a company in November 1996. The key objective of establishing the company, however, is to take over the power transmission system in Bangladesh and operate the network efficiently, providing bulk power transport between generation units and the distribution centres. Among other major activities which may be entrusted to PGCB at some point in time are the role of bulk power purchaser, long-term power demand estimation as well as the planning and procurement of future generation and transmission requirements. At the outset, PGCB is expected to carry out procurement and management of the transmission lines associated with Meghnaghat Power Company as well as the proposed National Load Despatch Centre (NLDC). It is expected that the entire transmission system would be handed over to PGCB by 2000.

Nevertheless, preparatory work to clearly identify the options available and to develop a time-bound plan for the handover of the transmission network to PGCB, if found feasible, has not yet been done. In addition, studies must be conducted to identify the long-term objectives of the new company, prepare corporate and business plans and secure needed institutional development assistance. It is necessary to recognize that substantial additional support will be required to assist PGCB in developing its corporate goals, preparing an action programme to realize these objectives of the new company, assessing assets and liabilities, developing suitable financial models, a management structure, staff training and support facilities and resolving issues related to assets and personnel transfers. In particular, it is necessary to examine the implications of a staged transfer of the transmission network as against handing over an integrated network on a single date. Any other options deemed feasible must also be considered and analysed. It is also necessary to examine issues connected with the construction and operation of the proposed NLDC in the context of the ownership of the transmission facilities and grid substations.

E. ENVIRONMENTAL CONSIDERATIONS

1. General

The population of Bangladesh in 1991 was estimated to be 110.6 million, of whom 83 per cent live in rural areas and only about 17 per cent in urban surroundings. The population growth rate of the country is around 2 per cent per annum, which although moderately high, is nevertheless a vast improvement over the rate of 2.8 per cent 20 years ago. At the end of 1996 it had exceeded 120 million. By 2025, the population is projected to reach 180 million.

Bangladesh is small in area (143,999 km^2), but has a population density of 770 people per km^2, which is one of the highest in the world (excluding city States). With the exception of the eastern hills along the borders with India and Myanmar, the country is very flat. The country consists mainly of an alluvial plain at the delta of the rivers Ganges, Brahmaputtra (Jamuna) and Meghna. The soils are very fertile owing to centuries of flooding and siltation.

The amount of total land area which is cultivated is 76 per cent. The average cultivated land per capita for the rural population is only 0.12 ha, or roughly 1 ha per farm household. To make matters worse, much of the country is still subject to serious flooding from seasonal high river flows or from cyclones and tidal surges in the Bay of Bengal. Bangladesh is also a poor country, with an average GNP per capita of only $220 in 1995. This compares with a world average of $4,010 and an average for low-income countries of $350. Within Bangladesh, 50 per cent of the population is below the poverty line, and 30 per cent in dire poverty.

Bangladesh receives an abundance of rainfall, but it is very seasonal, with winter drought and a summer monsoon period. Natural precipitation is adequate for the summer crops, but the winter crops require irrigation. The sources of irrigation water include surface supply, i.e. pumped from the rivers, and groundwater supply, which is mainly pumped from shallow tube wells.

About 14 per cent of the land area is covered by forests. These include tropical evergreen and semi-evergreen forests in the eastern Hill Tracts (27 per cent of the forest area); moist/dry deciduous forests in terrace areas (5 per cent); tidal/mangrove forests in the Sundarban (26 per cent); and "unclassified state forests" (42 per cent) which are administered by district authorities but are subject to encroachment and degradation from economic development pressures.

Most rivers in Bangladesh carry high sediment loads which are constantly being deposited along the river courses and out into the Bay of Bengal. The rivers are wide and have extensive active floodplains. Because the surrounding land is so flat and low, the rivers meander and change course regularly. Despite high flows, river navigation is limited to relatively small craft, of perhaps 100-ton to 200-ton capacity, because the river channelization is poorly defined and always shifting. With the exception of the hills in eastern Bangladesh and the alluvial terraces north of Dhaka and in the northern region, the majority of the country is in fact floodplain.

Fisheries are an important component of the economy in terms of employment, income generation and nutrition. Fish provides about 4.8 per cent of daily protein supply. Bangladesh has good fishery resources in inland rivers, the south-western mangrove swamps and most coastal waters. Of the total fishing industry, 61 per cent comes from inland capture, 16 per cent from aquaculture and 23 per cent from marine fisheries. Shad and various carp species comprise the main catch from rivers. Aquaculture is mainly from fish ponds, which cover 150,000 ha of the country. Shrimp and other marine species are harvested along the coastal waters, and these constitute a large proportion of the fishery value, especially exports.

2. Environmental issues

Since independence, Bangladesh has been largely preoccupied with managing moderate economic development, starting from a very low base, with the aim of providing basic necessities to the population. Poverty is still the main issue and will remain so for many years to come, given the moderately high population growth rate, limited land resources and periodic natural calamities such as flooding and cyclone damage. To put environmental concerns into perspective, the average life expectancy in Bangladesh is still only 51 years, and more than 70 per cent of the adult population is illiterate.

In rural areas, the environmental conditions have been affected more by natural causes than by economic development. Although the land is intensively cultivated, the land-use patterns have existed for many generations.

In the urban areas, however, industrial and residential development has more serious environmental impacts in localized areas. The major concerns are poor solid waster management, effluent treatment and related health problems. Except in central Dhaka, air pollution is not a serious problem. The level of industrial development is still limited, and comprises only 16 per cent of GDP, compared with 26 per cent in Pakistan and 42 per cent in China, and the physical conditions tend to dispense and/or absorb the present low level of emissions.

Although the environment may not be considered a priority concern in Bangladesh, some important environmental issues should already be considered to include:

- Deteriorating urban environmental conditions
- Threat of global warming and rising sea level
- Protection of the sensitive environmental habitat

There is increasing awareness of the environment and the deteriorating conditions in urban areas in Bangladesh. For the poor, living conditions in urban areas are worse than in rural areas, since housing, access to safe water, food supply and nutrition are at low levels. Urban waste dumps and effluent discharging into stagnant bodies of water already present serious health conditions for the urban poor. At present, and again with the exception of central Dhaka, Bangladesh is less concerned about acid rain and air pollution. The most serious concerns are nitrogen oxide levels in large urban centres, which are mainly attributable to vehicular emissions. The urban population is only 17 per cent of the total but is growing at 6.1 per cent annually.

Regarding CO_2, Bangladesh is very worried about the implications of climatic warming and rising sea levels. Although Bangladesh does have environmental regulations, they have not yet been officially "Gazetted" and, therefore, cannot be enforced. Bangladesh is, nevertheless, one of the many countries supporting the argument that developed and industrialized countries should finance the environmental costs of meeting international standards.

Bangladesh has established a system of protected forests, national parks, wildlife sanctuaries and game reserves. Given the high population density, protection of these remaining habitats is essential to preserve the rich but sensitive wildlife and biota, particularly in areas like the Sundarban, the Hill Tract forests and the "Madhupur Jungle" forest north of Dhaka. Forests are currently being depleted at the rate of 10,000 ha annually, which is 0.5 per cent of the forested area each year. These natural habitats support an abundance of aquatic and terrestrial species, including Bengal tigers, crocodiles, turtles, monkeys and migratory birds.

Bangladesh is a signatory to the following international conventions:

- International Plan Protection Convention for Pests and Diseases (1968)
- International Convention for the Preservation of Pollution of the Sea by Oil (1981)
- United Nations Convention on the Law of the Sea (1982)
- Convention on International Trade in Endangered Species (CITES) of Fauna and Flora (1982)
- International Convention Relating to Intervention on the High Seas in Oil Pollution Causalities (1982)
- Convention Concerning Protection of the World Cultural and Natural Heritage (1983)

F. GENERATION OPTIONS AND PREFERENCES

Bangladesh has limited power generation options. Renewable energy resources, such as large hydropower, use of wind power, geothermal, tidal power and solar, including photovoltaics, are yet to become cost-effective options. Conventional thermal power generation is the main option which utilizes non-renewable, rather depletable, energy supplies, such as natural gas, oil or coal. The preferred alternatives from an environmental standpoint include renewable options that have minimum impact on the natural or social environment. But apart from the one existing small hydropower site at Kaptai, the country has very limited other hydro potential, and the two sites identified in Section 5 (f) above are believed to have very significant socio-economic costs associated with the population which would have to be relocated. For thermal power, the preference would be to use natural gas-fired units, because there are relatively few impacts on emissions, fuel handling/storage and waste disposal. Improved energy technology options, such as combined-cycle units, would also be preferred over conventional steam units. If more steam units are to be built, consideration will have to be given to mitigating acid emission, at Chittagong and Mangla under Plan B-3 of PSMP, and ash disposal will be a consideration at Barapukuria. Nuclear units could offer good potential, but exceptionally high maintenance standards would be required to ensure safe handling and operation. Siting of nuclear plants should consider the potential risk to human safety and health.

The conventional thermal generating options are shown in table X.19 in terms of suggested environmental preference ranking (best to worst) in the context of Bangladesh.

1. Least-cost generation plan and policies

The choice of fuel for power plants is mainly guided by the fuel availability, transportation of fuel to the power plant site, price of fuel, and above all, the generation cost of the fuel. The environmental effects associated with the fuel are another aspect that deserves to be considered.

Studies have shown that gas-based generation is the least cost, while the next is the furnace oil based generation. Coal and nuclear fuel-based generation is costlier than gas-based and furnace oil-based generation.

In the light of the above, it has been found in the PSMP study that as long as gas is available (assuming no constraints on gas), the least-cost generation is the gas-based generation with most efficient new combined cycle power plants. This sequence has been termed in the PSMP the "Sufficient Gas" scenario.

It has been found in the PSMP study that if no further gas is available beyond the 10.2 TCF of net recoverable gas, and with 50 per cent allocation of gas for power generation in accordance with the energy policy, the new combined cycle of 1,200 MW capacity to be built up to fiscal year 2005 along with new gas turbines for peaking duty and the existing, under construction and committed gas-based power plants can run on gas up to the end of the life cycle. In this case, after fiscal year 2005, furnace oil-based thermal plants come up as a part of the least-cost solution. So this sequence of generation is entitled the "No New Gas" scenario (Plan B-3) and it is a mixed sequence of gas-based and furnace oil-based power plants, including Barapukuria coal power plants. It is to be noted that up to fiscal year 2005 Plan A-3 and Plan B-3 are the same.

Therefore, a decision point concerning a possible switch over to furnace oil-based power plants would have to be made by 2000 in the case of Plan B-3. It is expected that within this time period firm possibilities about further new gas availability would be known. It is to be mentioned that extensive exploration activities are going on in the country. Again, by 2000 and onwards, plants to be commissioned after fiscal year 2005 need to be processed for implementation.

Again, Barapukuria Coal, with an economic price of $1.86/GJ ($47.69/ton) and plant unit size of 150-125 MW has been found to be a slightly costlier option than imported coal. As an indigenous resource-based power plant, Barapukuria coal-based plant has been considered in both the sequences of Plan A-3 and Plan B-3.

Hydro potential is very limited in Bangladesh. The potential at Sangu and Mathamuhuri needs to be further investigated through new studies. The extension of Karnafuli also needs to be firmed up through further studies.

2. Conclusions and recommendations

(a) Gas-fired combined-cycle plants present few environmental problems and are the preferred viable option.

(b) If gas is not available, it is likely that plants along the Meghna River or at Chittagong and Mangla will be required, and will be based on imported oil or coal. While these plants would not be desirable, there is little alternative, and BPDB should try to identify good sites that minimize environmental impact.

(c) A small mine-mouth domestic coal plant is now essentially a committed project. It should be monitored. Fortunately, a mine-mouth plant is preferable. Fluidized-bed technology is not expected to be necessary, because of the low sulphur content of the coal.

(d) High-voltage transmission lines do not present a major problem, but the grid network should remain compact to reduce the length of the lines and corridors.

(e) Hydropower offers little potential, and no new plants are proposed in the PSMP. Options for storage reservoir are costly in terms of economic, environmental and social parameters.

(f) Other renewable energy resources should be encouraged, but they will be small in scale and will have little impact on the power system expansion plant.

(g) Demand-side management should also be encouraged, but it too will have little impact on the overall power system expansion plant.

Table X.19 Environmental preference for thermal generating options

Generation options	*Attributes*	*Problems*
Combined cycle (Gas-fired)	Energy efficient Low emissions Compact plant Medium unit sizes[a]	
Diesel generators	Energy efficient	
Combustion turbines (gas or diesel fuel)	Low emissions Compact plant No water use Small unit sizes[a]	Low energy efficiency Noise
Gas-fired steam plant	Low emissions Large unit sizes[a]	Moderate energy efficiency Cooling water use
Fluidized bed (domestic coal)	Low emissions Energy efficient Mine-mouth plants	Gypsum and ash disposal Indirect (coal mining/handling)
Peat-fired steam plant	Low emissions Domestic fuel	Low heat content Peat extraction
Nuclear	Fossil fuel savings No emissions Large unit sizes	Risk of radiation Spent fuel disposal Cooling water use Large land requirement
Oil-fired steam plant	Large unit sizes[a]	Moderate energy efficiency Fuel delivery/storage Acid gas emissions Effluents
Coal-fired steam plant	Large unit sizes[a]	Moderate energy efficiency Fuel delivery/storage Acid gas emissions Ash disposal Effluents Large land requirement

[a] Plant size can be an advantage or disadvantage, depending on the type of generation and transmission network that is deemed suitable for Bangladesh.

Table X.20 Power system development Plan A-3

Fiscal year	*Adjusted gross peak demand (MW)*	*Generation project*	*Nominal capacity (MW)*	*Gross capacity (MW)*	*System gross capacity (MW)*	*Gross capacity reserve %*	*Generation capital cost ($ x 10^6)*	*Transmission capital cost ($ x 10^6)*
1995	2 038				2 376	16.6		
1996	2 220	Committed	90	90	2 466	11.1		
1997	2 419	Committed	69	64	2 530	4.6		
1998	2 638	Committed	414	395	2 925	10.9		
1999	2 881	Committed	529	520	3 445	19.6		70.3
2000	3 149	Shahjibazar CT (planned)	20	20	3 639	15.6	13.0	70.3
		CT (new)-Mymensingh & Sylhet	200	174			115.2	
2001	3 383	Barapukuria No.1 (Coal)	125	125	3 986	17.8	162.5	49.8
		Baghaberi CT (planned)	71	71			46.1	
		Khulna Oil-Steam (planned)	210	210			134.8	
		CT-(new)-Chittagong	100	87			57.6	
2002	3 636	Barapukuria No.2 (Coal)	125	125	4 301	18.3	162.5	49.8
		Combined Cycle-Meghnaghat	300	269			253.2	
2003	3 909	CT-(new)-Chittagong	100	87	4 657	19.1	54.7	49.8
		Combined Cycle-Meghnaghat	300	269			227.9	
2004	4 204	Shahjibazar CT (planned)	40	40	5 053	20.2	25.8	49.8
		CT-(new)-Chittagong	100	87			54.7	
		Combined Cycle-Baghabari	300	269			253.2	
2005	4 523	CT-(new)-Chittagong	200	174	5 496	21.5	112.3	49.8
		Combined Cycle-Baghabari	300	269			227.9	
2006	4 872	CT (new)	300	261	5 900	21.1	169.9	65.9
		Combined Cycle-(new)	600	538			506.4	
2007	5 249	CT (new)	500	435	6 261	19.3	276.5	65.9
2008	5 656	Combined Cycle-(new)	600	538	6 799	20.2	481.1	65.9
2009	6 094	Combined Cycle-(new)	600	538	7 297	19.7	481.1	65.9
2010	6 567	CT (new)	600	522	7 819	19.1	334.1	65.9
2011	7 076	CT (new)	100	87	8 424	19.0	54.7	40.3
		Combined Cycle-(new)	600	538			455.8	
2012	7 625	CT (new)	400	348	9 041	18.6	218.9	40.3
		Combined Cycle-(new)	300	269			227.9	
2013	8 218	CT (new)	200	174	9 753	18.7	112.3	40.3
		Combined Cycle-(new)	600	538			481.1	
2014	8 858	Combined Cycle-(new)	900	807	10 560	19.2	709.0	40.3
2015	9 548	CT (new)	300	261	11 359	19.0	167.0	40.3
		Combined Cycle-(new)	600	538			506.4	

Notes: 1-A-3 means overall least-cost expansion plan based on the assumption that enough gas will be found.

2-Gross peak demand is adjusted for gradually reducing station service load.

3-Nominal capacities of future units are shown at ISO conditions (15°C, at sea elevation).

4-Gross capacities are shown at site conditions (35°C).

Table X.21 Power system development Plan B-3

Fiscal year	*Adjusted gross peak demand (MW)*	*Generation project*	*Nominal capacity (MW)*	*Gross capacity (MW)*	*System gross capacity (MW)*	*Gross capacity reserve %*	*Generation capital cost ($ x 10⁶)*	*Transmission capital cost ($ x 10⁶)*
1995	2 038				2 376	16.6		
1996	2 220	Committed	90	90	2 466	11.1		
1997	2 419	Committed	69	64	2 530	4.6		
1998	2 638	Committed	414	395	2 925	10.9		
1999	2 881	Committed	529	520	3 445	19.6		70.3
2000	3 149	Shahjibazar CT (planned)	20	20	3 639	15.6	13.0	70.3
		CT (new)-Mymensingh & Sylhet	200	174			115.2	
2001	3 383	Barapukuria No. 1 (Coal)	125	125	3 986	17.8	162.5	49.8
		Baghaberi CT (planned)	71	71			46.1	
		Khulna Oil-Steam (planned)	210	210			134.8	
		CT-(new)-Chittagong	100	87			57.6	
2002	3 636	Barapukuria No. 2 (Coal)	125	125	4 301	18.3	162.5	49.8
		Combined Cycle-Meghnaghat	300	269			253.2	
2003	3 909	CT-(new)-Chittagong	100	87	4 657	19.1	54.7	49.8
		Combined Cycle-Meghnaghat	300	269			227.9	
2004	4 204	Shahjibazar CT (planned)	40	40	5 053	20.2	25.8	49.8
		CT-(new)-Chittagong	100	87			54.7	
		Combined Cycle-Baghabari	300	269			253.2	
2005	4 523	CT-(new)-Baghabari	200	174	5 496	21.5	112.3	49.8
		Combined Cycle-Baghabari	300	269			227.9	
2006	4 883	CT (new)	300	261	5 862	20.1	167.0	90.6
		Oil-Steam (new)	500	500			514.0	
2007	5 271	Oil-Steam (new)	500	500	6 288	19.3	514.0	90.6
2008	5 691	Oil-Steam (new)	500	500	6 788	19.3	436.9	90.6
2009	6 145	CT (new)	600	521	7 269	18.3	334.1	90.6
2010	6 635	CT (new)	100	87	7 856	18.4	54.7	90.6
		Oil-Steam (new)	500	500			436.9	
2011	7 157	CT (new)	100	87	8 423	17.7	54.7	120.1
		Oil-Steam (new)	500	500			436.9	
2012	7 720	CT (new)	100	87	9 010	16.7	54.7	120.1
		Oil-Steam (new)	500	500			436.9	
2013	8 329	CT (new)	200	174	9 684	16.3	115.2	120.1
		Oil-Steam (new)	500	500			436.9	
2014	8 986	CT (new)	300	261	10 445	16.2	167.0	120.1
		Oil-Steam (new)	500	500			514.0	
2015	9 696	CT (new)	300	261	11 206	15.6	164.2	120.1
		Oil-Steam (new)	500	500			436.9	

Notes: 1-B-3 means expansion plan based on the assumption that no new gas field will be found.
2-Gross peak demand is adjusted for gradually reducing station service load.
3-Nominal capacities of future units are shown at ISO conditions (15°C, at sea elevation).
4-Gross capacities are shown at site conditions (35°C).

XI. ENERGY INFRASTRUCTURE IN CHINA*

A. ENERGY AND ECONOMIC GROWTH

Since 1992, the gross national product (GNP) has maintained a high rate of growth with two-digit numbers. During the eighth five-year plan, the increase annually averaged 11.6 per cent, approximately 1.9 per cent higher than during the seventh five-year plan (1986-1990), being the highest rate in history. The strategic target of having GDP doubled twice by 2000 from that of 1980 has been attained five years ahead of schedule.

During the eighth five-year plan, in terms of the whole country the rapid economic growth did not lead to serious energy shortages, showing that great changes have occurred in the energy supply-demand relationship. The reasons for such changes include:

(1) Effect of energy conservation derived from the reform of market-oriented reform;

(2) Rapid increase in the number of township and village enterprises with less energy consumption per unit product value and the third industry enterprises, the proportion of over two thirds of energy saving resulting from the changes of economic structure in the total energy saving;

(3) End demand of energies changing toward high quality and high efficiency; demand for oil, gas and electric power far exceeding that of coal and biomass energy; and the residential demand for energy becoming more apparent in the south-east coastal areas;

(4) The drastic increase in the import of oil and energy-intensive raw materials;

(5) Persistent surplus of coal production since 1992 (the coal storage of the whole country exceeding the normal level).

B. ENERGY PRODUCTION AND CONSUMPTION

1. Energy production

In 1995, China's total primary commercial energy production was 1,287.3 Mtce, 8.4 per cent higher than in the previous year, annually increasing 4.8 per cent on average from 1991 to 1995. In the total energy production, the share of raw coal was 1,360.0 Mt, that of crude oil 150.05 Mt, natural gas, 17.60 billion m^3, and hydropower, 188.0 TWh. Nuclear power accounted for 12.9 TWh.

Little change occurred in the mix of the primary energy production. In 1990, coal took 74.2 per cent, oil 19.0 per cent, natural gas 2.0 per cent and hydropower 4.8 per cent, in 1995, coal took 75.5 per cent, oil 16.7 per cent, natural gas 1.8 per cent, hydropower 6.0 per cent and nuclear power 0.4 per cent.

Electric power production in 1995 was 1,007.7 TWh, increasing annually 9 per cent on average from 1991 to 1995.

At present, China has the third largest energy system in the world, with the total production of primary energy coming closely after that of the United States and the Russian Federation. During the eighth five-year plan, China kept the rank of first in raw coal production in the world, and the rank of fifth in crude oil production, and rose from fourth up to second rank in electric power production. However, the per capita level was very low.

2. Energy consumption

In 1994, consumption of primary commercial energy was 1,227.37 Mtce in the country, increasing 5.8 per cent from the previous year, in which coal made up 75.0 per cent, oil 17.4 per cent, natural gas 1.9 per cent, hydropower 5.3 per cent and nuclear power 0.4 per cent.

The consumption of primary commercial energy by sector was: 4.10 per cent in agriculture, 71.6 per cent in industries, 1.1 per cent in the building industry, 4.6 per cent in communication and transport, 1.5 per cent in the commercial sector, 4.5 per cent in

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the non-productive department, and 12.6 per cent in the residential sector.

Consumption of non-commercial energy (including firewood and straw) in rural areas amounted to 247.8 Mtce in 1994. In addition, consumption of other new energies, such as solar energy, wind power, biogas, geothermal energy and tidal energy etc. in that year was 2.0 Mtce.

Calculated in terms of the international prevailing energy balance table, final consumption of commercial energy in 1994 (electric power converted to coal equivalent by the average fuel consumption of thermal power plants) was 853.62 Mtce, of which 5.0 per cent was consumed in agriculture, 59.6 per cent in industries (including the building industry), 12.1 per cent in communication and transport and 23.3 per cent in residential and commercial uses (including others).

Consumption of primary energy, including commercial energy, non-commercial energy and new energy in 1994 totalled 1,447.17 Mtce, ranked second in the world; within the consumption of primary energy, coal accounted for 62.32 per cent, oil 14.46 per cent, natural gas 1.58 per cent, hydropower 4.40 per cent, nuclear power 0.33 per cent, biomass energy 16.78 per cent, and new energy 0.13 per cent.

The net oil import in 1994 was 3.66 Mt, 62.7 per cent lower than in the previous year, and representing 2.45 per cent of the energy consumption of the country.

Energy consumption per capita in 1994 was 1,236 kgce, of which commercial energy consumption was 1,024 kgce, electric power consumption per capita, 642.2 kWh, and electric power consumption per capita for households, 72.7 kWh.

C. COAL INDUSTRY

1. Overview

China's coal industry is large-scale. As of 1994, a total of 1,947 state-owned coal mines (of which 104 mines were state-owned key mines) and 67,000 town and village-owned coal mines were scattered in the 1,257 counties of 28 provinces, municipalities and autonomous regions nationwide. The national coal output amounted to 1,239.9 Mt, accounting for 27.9 per cent of the world's total. China's coal industry employs a workforce of 8.25 million people. Its fixed assets amount to 155.66 billion RMB (not including those of town and village-owned coal mines). Coal preparation plants total 203.

In July 1994, the mandatory coal price was only limited to the coal to be supplied to the electric power plants. On the whole, strict control over the coal price was called off. With regard to the state-owned key mines, their losses were reduced from 5.57 billion RMB in 1990 to 1.97 billion RMB in 1994.

2. Coal production

China's raw coal production in 1994 was 1,239.9 Mt, an increase of 7.85 per cent over the previous year. The state-owned key mines produced 468.67 Mt, 37.8 per cent of total national production, and a 2.3 per cent increase over the previous year; state-owned local mines produced 205.96 Mt, 16.6 per cent of the national total and 0.9 per cent more than the previous year; collectively-owned coal mines produced 485.0 Mt, 39.1 per cent of the national total and 12.8 per cent more than the previous year; private mines produced 73.59 Mt, 5.9 per cent of the national total and 39.0 per cent more than the previous year; while other mines produced 6.68 Mt, 0.6 per cent of the national total. In term of the types of coal produced, anthracite coal accounted for 20.2 per cent of the national total coal production, bituminous coal 76 per cent (of which coking coal accounted for 46.6 per cent) and lignite 3.8 per cent of the national total.

In 1994, a total of 245 Mt of raw coal underwent coal preparation processes, about 19.8 per cent of the total raw coal production. The cleaned coal for coke-making totalled 77.73 Mt in the whole country; the ash content in the saleable coal produced by the state-owned key coal mines averaged 19.88 per cent and the waste content 0.09 per cent; the ash content in washed coal averaged 9.97 per cent.

The gross output value of China's coal industry in 1994 was 107.54 billion RMB, of which that of state-owned enterprises accounted for 77.6 per cent.

3. Coal mine construction

In 1994, a total of 14.11 billion RMB was put into the capital construction of state-owned key mines, 3.4 per cent less than the previous year. Of the total, investment made by the Government accounted for 18.85 per cent, domestic loans accounted for 63.86 per cent, self-financing accounted for 8.36 per cent and foreign investment 6.66 per cent. In the same year, a total of fixed assets of 6.87 billion RMB was added to coal industry. Also in the same year, 33 new coal mines and 3 washed coal plants were commissioned, with overall annual capacities of 7.1 Mt and 6.7 Mt respectively. As of the end of

1994, 411 coal mines and 29 washed coal plants were under construction with overall capacities of 199.2 and 58.9 Mt respectively.

A total of 28 key projects were under construction, with an overall annual capacity of 78.7 Mt.

4. Coal market

In 1994, China's domestic coal consumption amounted to 1,285.3 Mt, of which coal consumption by agriculture accounted for 17.8 Mt, 1.4 per cent of the total; the power industry 392.9 Mt, 30.6 per cent of the total; coke-making 211.0 Mt (of which 75 Mt were consumed by coke-making with primitive methods), 16.4 per cent of the total; other industries 478.9 Mt, 37.2 per cent of the total; railways 18.7 Mt, 1.5 per cent of the total; household use 130.5 Mt, 10.1 per cent of the total; the commercial sector 10.2 Mt, 0.8 per cent of the total; and other sectors 25.3 Mt, 2.0 per cent of the total.

Ever since 1993, when mandatory coal prices were called off, the coal market in China has undergone new changes in that coal production from town and village coal mines increased from 425.5 Mt in 1992 to 554.9 Mt in 1994. On the other hand, the quantity of coal sold by state-owned key mines was reduced from 418 Mt in 1992 to 412.8 Mt in 1994. In the whole country, coal supply far surpassed the demand, which was an unprecedented phenomenon. At that time, China's coal stockpile was 30 per cent higher than the normal level. The stagnant coal market is the inevitable result of lack of necessary adjustment and control measures from the government. In 1994, measures were taken to restrict coal production and reduce the coal stockpile. As a result, the stockpile declined almost down to the normal level by the end of 1995.

In 1994, China exported a total of 24.3 Mt of coal, 12.3 per cent more than the previous year, while coal imports amounted to 1.22 Mt, 14.7 per cent less than the previous year.

D. PETROLEUM AND NATURAL GAS INDUSTRY

1. Outline

In 1994, the output of crude oil in China was 146.1 Mt, up 0.6 per cent from the previous year, and that of natural gas was 17.56 billion m^3, up 3.6 per cent from the previous year.

China has abundant oil and gas resources. The oil and gas resource assessment jointly carried out in 1993 by the China National Petroleum Corporation (CNPC) and the China National Offshore Petroleum Corporation (CNOPC) showed that China had total oil resources of 94 billion tons, along with natural gas, 38 trillion m^3.

In 1994, there were 308 oil fields and 81 gas fields being developed in both onshore and offshore areas in China, from which the production of crude oil reached 400 Kt/day (2.92 Mb/d), and that of gas 48.1 Mm^3/day (1.698 Gft^3/d).

China National Petrochemical Corporation has 38 oil refineries and petrochemical enterprises. In 1994, it had an oil-processing capacity of 148 Mt/year (being 86.9 per cent of the total of the country), and an ethene-producing capacity of 2.1 Mt (88.2 per cent of the total for the country).

2. Oil and gas exploration and development

So far, a total of 15 contracts on oil and gas exploration and development have been signed between CNPC and foreign oil companies from the United States of America, Japan, France, the United Kingdom, Italy, Australia, New Zealand and the Republic of Korea, involving a total investment of $486 million. Meanwhile, CNPC is also making efforts to participate in oil exploration and production in foreign countries. It has received stock rights, operational rights and leasing rights in Peru, Canada and Thailand etc., and has began cooperation with the Middle East and the Russian Federation, CNPC expects to produce 10 Mt of crude oil from abroad by 2000.

By the end of November 1995, a total of 109 contracts and agreements had been signed with 62 foreign companies from 16 countries and regions, directly attracting foreign investment of about $5.1 billion ($2.89 billion for risk exploration and $2.21 billion for development), 58 per cent of the total investment in offshore exploration and development.

In 1994, a new crude oil reserve in place of 28 Mt and a new gas reserve in place of 90 Gm^3 were increased. Production from offshore fields was 6.47 Mt of crude oil, 22 per cent higher than in the previous year, and 370 million m^3 of gas, 39 per cent higher than in the previous year. Ya13-1 gas field, with an annual production capacity of 3.45 billion m^3, began formally supplying gas to Hong Kong on 1 January 1996.

CNOPC is attempting to participate in oil and gas exploration and development in foreign countries. It has bought a 32.58 per cent stock share of the Malaca oil field, Indonesia, receiving 427 thousand tons of crude oil.

3. Petroleum processing

In 1994, the country processed 126.86 Mt of crude oil, declining 0.9 per cent from the previous year; this was the first decline since the 1981 production of gasoline, kerosene, diesel and lubricant in that year was 65.83 Mt, down 5.5 per cent from the previous year. One of the major reasons causing the decline was the excessively large imports.

The crude oil processing capacity of the country in 1994 was 170 Mt/year, up 10 Mt/year from the previous year. The total capacity of the refineries for secondary oil processing in the country was 76.39 Mt/year, up 9.55 per cent from the previous year.

In 1994, the country produced 26.95 Mt of gasoline, 33.14 Mt of diesel and 29.09 Mt of fuel oil, down 10.8 per cent, 2.1 per cent and 5.3 per cent, respectively, from the previous year. Production of petrochemical raw materials increased more. Liquefied petroleum gas reached 3.12 Mt, up 12.5 per cent from the previous year.

4. Oil and gas market

In 1994, the total consumption of oil products in the country was 131.1 Mt, up 2.2 per cent from 1993, whereas the increase from 1992 through 1993 was 12.5 per cent. This was mainly because of the overly high price level of the oil products, the tightening of the money market by the government to control inflation and the restraining of oil product demand.

In May 1994, the Chinese Government began reform of the circulation system of crude oil and oil products. Before the reform, the wellhead price of crude oil had remained at a low level but the price of oil products at a high level, while both the crude oil and oil products had two prices within and outside the plan, between which there were large differences; for example, the highest market price of crude oil from Daqing oil field attained 1,500 RMB/t, 1.5 times higher than the plan price, and the plan price of gasoline was only 1/3-1/4 of the market price. That resulted in serious confusion in the circulation order.

For this reason, three measures have been adopted in the reform of the circulation system of crude oil and oil products: abolishing the "two-track system" of the price of crude oil and oil products with the prices unified by the Government, strengthening the macro control on oil supply and demand with the production, import and export and distribution of crude oil and oil products controlled by the Government, reforming the circulation order and cleaning up illegal sale units.

After reform, the price of crude oil can be divided into two grades and five types. The first grade includes two types, e.g. the price of the crude oil of Daqing type is 754 RMB/t, and that of the Shengli type 684 RMB/t, up 150-160 RMB/t. The second grade includes three types, the Daqing type 1,310 RMB/t, the Shengli type 1,220 RMB/t and the heavy oil of the Liaohe and Shengli type 1,160 RMB/t. According to the distribution plan of crude oil and the proportion of the first and second grade price oil of 1995, it is calculated that the prices of crude oil average 860 RMB/t, 735 RMB/t after deducting the value-added tax, equivalent to $12/bbl.

The producer prices of the oil products from all the refineries of the country and the retail prices in 35 major cities are both determined by the Government. The total price level after reform is slightly higher than that at the end of 1993. In the fourth quarter of that year, the total price level of oil products tended to be stable owing to the limitation of imports, but the wholesale price of diesel rose in north China, east China and south China, up 30-40 RMB/t. In the first half of 1995, the price of oil products remained at a stable level.

5. Petroleum trade

In 1993, China changed from an oil net exporting country to an oil net importing country, with the import of crude oil and oil products reaching 32.96 Mt (crude oil 15.67 Mt and oil products 17.29 Mt), increasing 73.2 per cent from the previous year, but the exports reached 23.15 Mt (crude oil 19.43 Mt and oil products 3.72 Mt), decreasing 13.9 per cent from the previous year, the net imports being 9.82 Mt.

In 1994, the import of crude oil and oil products declined considerably, to 25.23 Mt (crude oil 12.34 Mt and oil products 12.89 Mt), down 23.5 per cent from the previous year. The reason for the decline in imports of 1994 is the overly large amount of imports in the second half of 1993 and the beginning of 1994, which caused supply greater than demand.

In 1994, China continued to be a net crude oil exporting country, with exports reaching 18.55 Mt, with the net exports increasing from 3.76 Mt of the previous year to 6.21 Mt. Exports from Daqing and Shengli made up 81 per cent and 18 per cent of the total amount, respectively. Of the exported oils, 64.4 per cent was supplied to Japan, and the rest to the United States of America, Republic of Korea, Democratic People's Republic of Korea and Singapore, etc. The export of oil products increased 2 per cent, reaching 3.79 Mt (gasoline 2.10 Mt, and light diesel 1.20 Mt).

In 1995, the demand for oil kept on growing. The drop in oil prices on the international market, occurring in the second half of the year, stimulated the increase in imports, so that the import of crude oil reached 17.09 Mt, up 38.4 per cent from the previous year, and the import of oil products reached 14.40 Mt, up 11.7 per cent from the previous year. Exports of crude oil increased a little, reaching 18.85 Mt, up 1.9 per cent from the previous year. Exports of oil products amounted to 4.14 Mt, up 9.2 per cent from the previous year.

E. ELECTRICITY

1. Overview

Since 1994, China's electric power industry has achieved new progress in reform and development. The Electric Power Law issued on 28 December 1995 has been in force since 1 April 1996.

China's electric power industry continuously maintains a high growth rate. By the end of 1994, the total installed capacity was 199.90 GW, which means an increase of 16.99 GW, or 9.3 per cent over the previous year, of which hydropower amounted to 49.06 GW, accounting for 24.5 per cent; thermal power amounted to 148.74 GW, accounting for 74.4 per cent; nuclear power amounted to 2.1 GW, accounting for 1.1 per cent; electricity generation reached 928.1 TWh, 10.6 per cent more than the previous year, of which, hydropower amounted to 168.1 TWh, accounting for 18.1 per cent; thermal power amounted to 745.9 TWh, accounting for 80.4 per cent; and nuclear power amounted to 14.04 TWh, accounting for 1.5 per cent.

By the end of 1995, the total installed capacity reached 210 GW, and the annual generating electricity exceeded 1,007.7 TWh, of which the share of hydropower was 188.0 TWh, and nuclear power 12.9 TWh.

In 1994, fuel consumption of thermal power stations (over 6 MW units) was 282.05 Mtce, an increase by 10.7 per cent compared with the previous year, of which raw coal was 392.91 Mt, an increase by 8.5 per cent; oil 11.64 Mt, a decrease by 3.2 per cent; and gas 8,532.13 Mm^3, an increase by 4.3 per cent. The rate of generation energy to primary energy consumption was 28.84 per cent.

The energy conversion efficiency of thermal power stations was 38.05 per cent, an increase by 1.54 per cent over the previous year; of which thermal efficiency of generation was 32.70 per cent, an increase by 2.54 per cent, and thermal power efficiency of heat supply was 83.99 per cent, a decrease by 2.53 per cent.

The net fuel consumption for thermal power stations was 414 gce/kWh and 381 gce/kWh at the generating end, a decrease by 3 gce/kWh over the previous year.

The electricity consumed by power plant uses was 6.9 per cent, a decrease by 0.06 per cent over the previous year, of which hydropower was 0.42 per cent, an increase by 0.01 per cent, and thermal power 7.99 per cent, a decrease by 0.09 per cent.

The annual utilization hours of all types of power stations (above 500 kW) were 5,233 h, an increase by 165 h over the previous year; of which hydropower was 3,877 h, an increase by 147 h, and thermal power stations, 5,574 h, an increase by 119 h.

In 1994, there were 14 electric networks in China with a capacity of over 1 GW. The largest was the East China power system, with a system capacity of 31.67 GW.

The total installed capacity of the 14 networks was 184.12 GW, and their annual generation was 890.2 TWh, accounting for 92.1 per cent and 95.9 per cent of the national total respectively.

In 1994, the capital investment of the electric power industry reached 72.6 billion RMB, an increase by 30.1 per cent over the previous year, of which the share of hydropower was 23.0 per cent, thermal power 54.7 per cent, and transmission and transformers 18.8 per cent. The original value of fixed assets in the power system was 298.6 billion RMB, and sale revenue reached 143.52 billion RMB. The total number of employees of the electric power industry was 2.098 million.

In 1994, the average power price of electric power companies was 221.02 RMB/MWh, the highest being 463.12 RMB/MWh in the Hainan provincial power company and 386.64 RMB/MWh in the Guangdong power bureau. The lowest was only 116.32 RMB/MWh in Qinhhai Province.

The electric power industry is the biggest industrial sector which uses foreign investment. By the end of 1994, it had used an cumulative amount of $12.1 billion of foreign investment to build 64 medium and large projects, with a total capacity of 40.70 GW, of which 19.57 GW had been put into operation.

2. Electricity demand and supply

In 1994, the total installed capacity of electric equipment for final use amounted to 460.18 GW which was 2.3 times the total generating capacity, an increase by 7.06 per cent compared with the previous year. The national electricity consumption was 904.65 TWh, an increase by 10.31 per cent over the previous year, of which, 87.48 TWh was consumed by household uses, accounting for 9.4 per cent, an increase by 19.95 per cent; 682.25 TWh was consumed by industry, accounting for 75.4 per cent, an increase by 8.5 per cent; 56.74 TWh was consumed by the agriculture, forestry, animal husbandry, fishing and water resources sectors, accounting for 6.3 per cent, an increase by 9.76 per cent; 9.65 TWh was consumed by the building sector, accounting for 1.1 per cent, an increase by 18.26 per cent; 0.81 TWh was consumed by the geological survey and prospecting industry, accounting for 0.1 per cent, an increase by 22.87 per cent; 16.75 TWh was consumed by the transport, communication and telecommunication sectors, accounting for 1.9 per cent, an increase by 10.75 per cent; 16.47 TWh was consumed by the commercial sectors, accounting for 1.8 per cent, an increase by 23.4 per cent; and 34.5 TWh was consumed by other sectors, accounting for 3.8 per cent, an increase by 17.30 per cent.

In 1994, several features in electric demand and supply were as follows:

- ❑ Power demand growth rates were unbalanced in the different regions, and this led to great variations in power generation growth in different networks.
- ❑ The great difference between peak and valley periods makes a considerable amount of trouble for peak power dispatch.
- ❑ The quality of electricity is being improved. The ratio of the qualified frequency in the country's main networks had reached 98 per cent.
- ❑ Conflicts between power supply and demand are serious at peak periods. Up to now, east China's electricity deficit at peak periods amounted to 1 GW. In a Beijing summer, the daily maximum deficit reached 600 MW. North-west and Hebei's deficit amounted to 1 GW at peak periods.
- ❑ Electricity consumption per capita is still low. In 1994, the national installation capacity per person was only 0.17 kW, the consumption per capita was 755 kWh, and household consumption per capita was 72.7 kWh.

3. Rural electrification

By the end of 1992, 28 counties and 120 million residents throughout the country had no access to electricity. The Ministry of Electric Power Industry proposed that, by the year 2000, all counties nationwide would gain access to electricity, and the percentage of households with access to electricity would amount to 95 per cent. In 1994, the project "poverty shaken off by the use of electricity" began to be enforced. By the end of 1995, 12 counties originally with no electricity had access to electricity; 16 counties with a population of 100 million remained without electricity.

From 1991 to 1994, the total technical investment in the rural network reached 11.22 billion RMB, with 0.445 million high loss transformers and 445 substations to be innovated, and nearly 1,000 mini-substations and 334 county-level network dispatching automatic systems to be constructed, to realize telecommunication connections in nearly 500 counties. In the 10 pilot counties for saving power, the total investment reached 0.16 billion RMB; in rectifying high and low lines, high loss of equipment and other projects, the annual saving of power reached 230 GWh.

4. Hydropower

Hydropower resources from rivers were estimated at 676 GW in theory, with an annual generation of 5,922.2 TWh, of which 379 GW and 1,923.3 TWh are evaluated as technically exploitable resources. An estimation made in 1992 proclaimed that the economically exploitable resources were 290 GW and 1,260 TWh (not including pumped storage stations). The total hydropower installed capacity exploited in 1994 was 49.06 GW, 16.9 per cent of the economically exploitable resources; the hydropower output was 168.1 TWh and accounted for 13.3 per cent of the economically exploitable output.

Since the 1990s, newly added hydropower installed capacity has grown rapidly; the newly added hydropower installed capacity of large- and medium-sized units in 1991 was 1.15 GW, 2.13 GW in 1992, 3.35 GW in 1993. In 1994, newly added capacity over 500 kW units was 4.03 GW, of which large- and medium-sized units were 3.76 GW. In that year, there was the most rapid increase in the number of new units in history.

At the beginning of 1995, the construction scale of national hydropower stations was 44.7 GW, of which the Three Gorges was 18.2 GW, and large- and medium-sized hydropower stations 21.2 GW.

In order to provide the coordinated operation of large thermal power stations and nuclear power stations with peaking capacity to the network, a group of pumped storage stations are under construction.

5. Thermal power

The main source of primary energy in China is coal. Thermal power stations will account for three fourths of the newly added capacity in the future. A certain amount of imported fuel oil and liquefied natural gas will feed the thermal power stations in the coastal areas.

The further development trend of thermal power is to construct a number of large thermal power bases near the coal mine areas, such as Shanxi, Inner Mongolia, Shaanxi, Henan, Guizhou and Yunnan. A number of large thermal power stations will be constructed in the load-concentrated area along the coast, near the sea and/or at railway junctions. The low and medium pressure thermal power units, as well as the units beyond their normal service life, will be rehabilitated or replaced by large units, in order to reduce fuel consumption; and to improve the environment, research, development and demonstration on clean coal technology will be carried out, including integrated gasification combined cycle generation, fluidized bed combustion, low NO_x combustors, and the flue gas clean-up technique. At present, prefeasibility studies are being carried out on 200-400 MW pilot plants using IGCC technology.

In the years to come, 300 MW and 600 MW units will generally be installed in new thermal power stations. Co-generation will be encouraged at the places where concentrated thermal loads are located. Some of the gas turbines and gas steam combined cycle units will be installed in the coastal areas.

In 1994, new installed thermal units over 500 kW totalled 12.16 GW, which accounted for 75.1 per cent of the total installation, including large and medium units of 7.89 GW. Because of a serious shortage of power, the capacity of small units reached 4.27 GW.

By the end of 1994, the total capacity of thermal power units over 6,000 kW was 137.30 GW, of which coal-fired units were 131.27 GW (95.6 per cent), gas turbine units 2.48 GW (1.8 per cent), and oil units 3.55 GW (2.6 per cent).

6. Nuclear power

China possesses nuclear fuel resources and nuclear technical forces. In east China, south China and the coastal area of north-east China, where are seriously short of energy sources, while the economy is well developed nuclear power is an appropriate solution to improve the local energy supply.

The first phase of the Qinshan nuclear power station (300 MW), and the two units of Daya Bay nuclear power station (2 x 900 MW) had been put into operation. The second phase of the Qinshan nuclear power station (2 x 600 MW), the third phase (2 x 700 MW), the second nuclear power station in Guangdong Province (2 x 1,000 MW) and the nuclear power station in Jiangsu Province (2 x 1,000 MW) will begin construction before 2000. A number of coastal provinces are carrying out the earlier stage work of the nuclear power project. In order to accelerate nuclear power development, efforts are focused first on the increase of the domestic-made components of the 600 MW pressurized water reactors, preparing for the batch production after 2000. At the same time, research and development are under way on the advanced concentration technique of nuclear fuel, 1 GW-class pressurized water reactors, and 600 MW advanced PWR with higher safety function and other new reactors.

F. NEW AND RENEWABLE SOURCES OF ENERGY

1. Overview

China is a developing country with 1.2 billion people, 860 million of whom live in rural areas. At present, 70 per cent of rural domestic fuel comes from biomass (firewood and straw). The consumption of biomass reached 248 Mtce, accounting for 40 per cent of the total rural energy consumption, and the consumption of firewood exceeded 30 per cent the volume of normal cut in 1994. This results in damage to plantation development as well as deterioration of the environment. At the end of 1995, there were still 100 million of the rural population living without electricity, of whom 70 million were living under the level of poverty. Therefore, the development of NRSE in China is not only the most important measure for sustainable development, but is also an important way to shake off poverty and build up a fortune for rural residents, living in areas short of electricity or with no electricity.

New and renewable sources of energy are rich and widely distributed in China. Since the 1980s, the implementation of the principle of "integrated and comprehensive use of various energy sources available with local conditions taken into account for obtaining social and economic benefits from the utilization of NRSE" has made great progress. In 1994, the volume of NRSE supply reached 318.7 Mtce, of which biomass was 248.0 Mtce, hydropower 68.7 Mtce, new sources of energy 2.0 Mtce, and NRSE accounted for 21.6 per cent of the total amount of primary energy consumption (the total of commercial and non-commercial).

For further promotion of the development of NRSE, the State Science and Technology Commission, the State Planning Commission, and the State Economic and Trade Commission formulated "The programme of NRSE development in China (1996-2010)" jointly in 1994, emphasizing the objectives, tasks, policies and measures for the development of NRSE in the coming 15 years. The general objective is to improve conversion efficiency, reduce costs, increase the proportion of NRSE in the energy consumption structure, make innovations in technology and put the mature technology into mass production so as to form the NRSE industry and service system.

2. Mini-hydropower

There are 76 GW-exploitable mini-hydropower resources (less than 25 MW) in China. The development and use of mini-hydropower resources plays an important role in speeding up rural electrification. State and local administration assists the construction of mini-hydropower stations with loans on favourable terms. By the end of 1994, more than 6,000 mini-hydropower stations had been built with a total installed capacity of 15.65 GW, producing 49 TWh of electricity and accounting for 54 per cent of the rural electric power consumption; 780 counties (accounting for 36 per cent of the total) have power supply mainly from mini-hydropower in China.

Based on the development of mini-hydropower, a programme for the implementation of elementary electrification at the county level (annual electricity consumption per capita and electricity consumption for living per household reach 200 kWh) was carried out in 1983. The first batch of 109 counties in 1990 and the second batch of 200 counties in 1995 were supplied with electric power, and 300 counties had their local grid rehabilitation. It is expected that there will be 1,000 counties reaching preliminary electrification level in 2000.

In addition, micro-hydropower (capacity less than 10 kW) has developed rapidly in recent years; there were more than 60,000 units in 1994 with a total installed capacity of 176 MW supplying electricity to 600,000 rural households.

3. Biomass for fuels

(a) Firewood and straw

In 1994, the planted area for firewood forest reached 6.0 Mha, and the normal cut volume was 145 Mt (83 Mtce), including other firewood resources. The output volume of straw reached 600 Mt (300 Mtce), of which about one half was consumed for fuels. The total amount of biomass consumption was 248 Mtce, of which firewood accounted for 40 per cent and straw 60 per cent.

(b) Efficient stoves

In recent years, the Chinese Government has spared no effort to disseminate efficient stoves in rural areas and has obtained fruitful results. By the end of

1994, there were 166 million rural households using efficient stoves, accounting for 72 per cent of the total. The thermal efficiency of the new stoves was above 25 per cent doubling that of the old ones.

The development of firewood forest and dissemination of efficient stoves make a significant contribution to protection of the forest resource, to improve the quality of life in rural households as well as the rural environment.

4. Biomass gasification

China is the biggest biogas consumer in the world. In 1994, 5.43 million domestic biogas digesters (180,000 more than that in 1993) producing 1,350 million m^3 of biogas (heat value 2,123 MJ/m^3), served as cooking fuel in rural areas; 583 medium/ large biogas supply systems using organic wastes as raw materials supplied biogas for 84,000 households in towns and small cities as daily cooking fuels; and 154 units of biogas-powered electricity generating systems had been built with a total installed capacity of 3 MW. Using anaerobic digestion technology, 30,000 units of sewage treatment systems have been built in a few small towns for waste treatment for 2.9 million people.

In recent years, the integrated use of by-products from biogas digesters has been disseminated and reaped economic, environmental and social benefits. For example, in Liaoning Province, there are 62,800 households having biogas digesters built in greenhouses integrated with pigsties/toilets. Sixty-two thousand ha of land were cultivated with seeds soaked with the digested slurry and achieved a 5 per cent increase in grain output.

Biomass gasification equipment using waste to produce clean gas for timber, agricultural product drying, heating and cooking, has been put in trial production; at present, its annual sales volume is only 100 or more, and there are 600 units in service.

5. Solar energy

China has rich sources of solar energy; two thirds of its territory is covered with solar radiation of 0.6 MJ/cm^2. At present, solar energy is mainly used for supplying heat and electricity to households in remote villages and small towns.

(a) Solar thermal utilization

The quantity of solar water heaters and passive solar houses in service is such that China ranks first in the world in this area.

In 1994, the aperture area of installed solar water heaters was above 3 million m^2. The performance of domestically produced heat pipe evacuated tubular solar collector and SUNSTRIP flat plate collector reached international standards. For example, a solar water heater with 1.1 m^2 (aperture area) of heat pipe evacuated tubular collectors can supply 50 kg/d of 45 °C hot water in winter.

In China, 5.75 million m^2 of passive solar houses have been built, mainly distributed in the rural areas of Hebei, Liaoning, Inner Mongolia, Gansu, Qinghai and Tibet; 400 primary and high school buildings in Liaoning Province are in the passive solar design. Generally, a passive solar building can save 20 $kgce/m^2$ (floor area) of coal in the heating season.

Up to now, the quantity of solar cookers in use is still at 140,000 units. A solar cooker can save at least 300 kgce of cooking fuel a year.

(b) Solar photovoltaic power source

At present, solar PV in China is mainly used as a power source for microwave communication systems and stand-alone power systems for off-grid remote homes. In 1994, the sales volume of solar PV panels reached 1.1 MW, and total installed capacity reached 6 MW. In Tibet, several solar PV power stations of 10 kW, 15 kW and 25 kW have been built, and another five are under construction.

6. Wind energy

Wind energy potential in China is distributed in south-east coastal areas, Xingjiang, Gansu, the northern part of Inner Mongolia and the north-eastern part of China, with an annual average wind energy density of 150-300 W/m^2 and 4,000-8,000 hours of time duration above the wind speed of 3 m/s. The total wind energy potential which could be utilized is estimated at 253 GW.

In 1995, there were 130,000 mini and small wind turbine generators (100 W-5 kW) in operation with a total installed capacity of 17 MW. The annual output of small wind turbines reached 30,000 units. In inner Mongolia, there are 100,000 small wind turbines generating 1,200 GWh/year of electricity for 600,000 herdsmen, a quarter of the total population in that region. There are 14 wind farms having 150 grid-connected wind turbines (50-450 kW) with a total installed capacity of 32 MW, mainly installed in Dabancheng of Xingjiang, Zhurehe and Shangdu of Inner Mongolia, Nanou of Guangdong, Dalian of Liaoning and Hangdao and Rongcheng of Shangdong. Most of the large wind turbines were imported ones. The domestically made 55-200 kW wind turbines are under development.

For the further promotion of wind power development, the Ministry of Electric Power implemented a new pricing policy for wind power generation in July 1994, stating that all the local power companies should purchase all the wind electricity to grid with the price including electricity generation cost, capital repaid with interest and some rational profits; the tax for appreciation would not be included in the price and levied according to the affordable capability of the consumers, and the surplus part of wind electricity price to average electricity price would be shared by the whole grid. In addition, there are 1,250 units of wind pumps irrigating 1,300 ha of dry land.

7. Geothermal energy

China is rich in geothermal resources: 2,500 hot springs and 270 reservoirs have been found with a hot water (>150 °C) capacity of 6,744 MW. The total proven exploitable geothermal resources reach 462.7 Gtce.

At present, there are 1,100 places, mainly distributed in Tianjin, Beijing, Fujian, Hebei, Jiangsu, Jiangxi, in direct use of low-temperature geothermal energy for plantation, aquaculture, space heating, and health care, with a total volume of 400 Ktce. In 1994, the scale of use of geothermal energy was: plantations and aquaculture – 3,328 ha; space heating floor area – 1.3 million m^2 and hot springs – 200 sanitarium, places.

The capacity of geothermal power generation reached 28.6 MW. The Yangbajing geothermal power plant in Tibet has a capacity of 25.2 MW and generates 97 GWh of electricity a year, accounting for 50 per cent of power supply in Lhasa. At the end of 1993, the temperature measured as high as 329.8 °C at 1,850 m depth of the first geothermal well in north Yangbajing district.

G. ENERGY AND ENVIRONMENT

1. Status of energy-related environment

The energy and environment issues in China are the pollutant emissions in the process of development and utilization of energy, and their impact on the ecosystem, especially the great damage to the atmosphere and ecosystem, owing to the enormous consumption of burning coal and biomass in urban and rural areas.

(a) Pollutant emission

Waste gas emission. The waste gas emission of the whole country (not including that from TVE) in 1994 was up to 11.4 x 10^{12} m^3, of which the emission of dust in waste gas and SO_2 was 14.14 Mt and 18.25 Mt respectively, almost the same as that of the previous year, while the industrial powder emission was about 5.83 Mt, 5.5 per cent less than that in 1993. It is estimated that nearly 85 per cent of the SO_2, emission of the whole country in 1994 was ascribed to burning coal.

Waste water discharge. The total amount of waste water (not including that from TVE) was 36,530 Mt in 1994.

Industrial solid waste. The yield of industrial solid waste was 620 Mt in 1994 (excluding the part from TVE). The accumulation of industrial solid waste was up to 6,460 Mt, occupying 55,697 ha.

Rural industries. The discharge of industrial powder, waste water and solid from TVE was 5.8, 4,300 and 120 Mt, respectively.

(b) Atmosphere quality

Particulate. The annual daily average suspended particulate in the atmosphere in urban areas reached 89-849 µg/m^3 in 1994. For cities in northern areas, this figure was 407 µg/m^3, and 250 µg/m^3 for cities in southern areas, maintaining the same level as that of the previous year. A total of 45 cities were found to exceed the second grade of national standard. The annual average dustfall was 3.2-64.61 t/km^2 per month. For cities in northern areas, the average was 24.76 t/km^2, and 10.57 t/km^2 for cities in southern areas. It is found that 57 per cent of the cities have surpassed the limit.

SO_2. The annual daily average concentration of SO_2 varied from 2 to 472 µg/m^3, of which 89 µg/m^3

and 83 μg/m^3 were for cities in the northern and southern areas respectively. There were 48 cities where the SO_2 emission exceeded the second grade of national standard, of which Chongqing and Guiyang were the most serious ones, and Yibin, Jinan, Wuzhou, Shijiazhuang, Tianjin, TaiRMB, Zibuo and Datong were comparatively serious ones.

Nitrogen oxide. Its annual daily average NO_x varied from 44-120 μg/m^3, 55 μg/m^3 in the northern cities, and 39 μg/m^3 in the southern cities, maintaining the same level as that of the previous year. NO_x emissions in Beijing, Guangzhou, Wulumuqi and Anshan exceeded the second grade of national standard.

Acid rain. Acid rain occurred mainly in the areas south of the Yangtaze River and east to the Qingzang plateau, as well as in the Sichuan basin. On the basis of statistics from 77 cities, the annual average pH value of precipitation is 3.84-7.54. The precipitation pH values in 48.1 per cent of the cities was below 5.6; 81.6 per cent of the cities were discovered to have acid rain, and the acid rain pollution was very serious in some cities.

(c) Ecological environment

The consumption of biomass energy (firewood and straw) was 248 Mtce in 1994, a 5.7 per cent drop compared with that in 1990. The over-consumption of firewood, which is one of the main reasons leading to water losses and soil erosion, was 30 per cent higher than the reasonable supply. The area of water losses and soil erosion has so far reached 3.67 million km^2 in China. The damage to the ecological system owing to the over-consumption of firewood has gradually been mitigated.

2. Environmental protection work

(a) Prevention and control of environmental pollution

Control of industrial pollutant emission. In 1994, 88.6 per cent of industrial enterprises above the county level carried out dust collection on flue gas from fuel combustion, a 2.4 percentage point increase over the previous year. The purification ratio for waste gas amounted to 71.8 per cent, a 1.7 percentage point increase over the previous year. The qualification rates of smoke dust emission for both industrial boilers and furnaces were 77.7 and 53.9 per cent, 1.6 and 1 percentage point increases over the previous year.

Developing gas and central heating. The supply of coal gas for household use in urban areas was 4.16 billion m^3, 2 billion m^3, 2.82 Mt for natural gas and LPG, respectively. The area of central heating reached 505.97 Mm^2, a 14.6 per cent increase over the previous year.

The urban population using gas reached to 104.218 million and the dissemination rate of residents using gas was up to 61.7 per cent, an increase by 4.7 percentage points over the previous year.

(b) Protection of the ecological environment

Afforestation. The total afforestation area was 5.333 million ha across China in 1994. A total of 3.667 million ha hillsides have been closed to facilitate afforestation. The cumulative area of man-made forest was up to 33.79 million ha. According to the Forest Energy Project put forward by the Ministry of Forestry in 1995, from 1996, it would take 20 years to develop a firewood forest of 12 million ha in the areas seriously lacking in firewood. A total of 3 million ha of firewood forest will be developed in 100 key counties from 1996 to 2000.

(c) Environment management

The State Planning Committee and the National Environmental Protection Agency (NEPA) promulgated Management Measures for the Environmental Protection Plan in 1994, and NEPA formulated the Technical Regulation on Ecosystem Impact Evaluation for Construction Projects. The project on state environment pollution control within time limits has been included in the national economic and social development plan. The licence system on air pollution control for trial implementation was carried out in 16 cities with the controlled emission sources of 6,646, and 13,447 licences have been distributed for the discharge of water pollutant in China. The discharge fee was 3.1 billion RMB in 1994. Pilot practices on imposing a levy on SO_2, emission continued to be conducted in the two provinces of Guangdong and Guizhou, and nine cities of Chongqing, Yibin, Nanning, Guilin, Liuzhou, Changsha, Hangzhou, Qindao and Yinchang.

H. FUTURE ENERGY DEMAND FORECAST FOR CHINA

Method for energy demand forecast. The LEAP (Long-range Energy Alternatives Planning) model is used to help the energy demand forecast; 1990 is taken as the base year, and 2000, 2010 and 2020 are the planned target years. Six major sectors with 17 subsectors and 11 kinds of end-use energy types are taken into consideration.

1. Assumptions for the planned indicators

Economic development. It is projected that the GDP growth rate from 1990 to 2000 will average 9 per cent annum from 2000 to 2010, and 7.5 per cent; and 6 per cent per year for 2010 to 2020. The economic growth rates of the first, second and third industry and sectors are shown in table XI.6.

Population. It is projected that the annual average population growth rate will be 12.5, 7.2 and 4.2 per cent during the periods 1990-2000, 2000-2010 and 2010-2020, respectively. According to the projection, the population will be 1.294, 1.39 and 1.45 billion, respectively: table XI.7 provides details.

Energy conservation rate. It is assumed that the nationwide annual average energy conservation rate will be 4.49, 4.42 and 3.35 per cent during the periods 1990-2000, 2000-2010 and 2010-2020, respectively.

2. Results of the energy demand forecast

According to the end energy consumption and the assumptions outlined, the LEAP model is used for energy demand forecasts for the target years. The results are presented in table XI.8 from the results of the energy demand forecast it can be concluded:

- The share of coal in end use will decrease from 33 per cent in 1990 to about 20 per cent in 2020
- The share of electricity in end use will rise from 17.7 per cent in 1990 to 35.5 per cent in 2020
- The share of oil and gas will increase from 13 per cent in 1990 to 22.4 per cent in 2020.

3. Forecast for the future electricity production of China

- The total installed capacity of electric power of China was 137.89 GW in 1990, of which hydropower was 36.05 GW, accounting for 26.1 per cent, Electricity generation reached 621.62 TWh, of which hydropower amounted to 126.47 TWh, accounting for 20.34 per cent.
- In 1990, the fuel consumption for thermal power stations was 202.18 Mtce, of which, 94.4 per cent came from coal, and only 5.65 per cent from fuel oil and gas.
- The average energy consumption for electricity generation was 392 gce/kWh, while generation gross efficiency was 31.4 per cent. The average unit consumption for thermal power stations was 427 gce/kWh at the consumer's end, and electricity supply net efficiency was 28.8 per cent.
- The main reasons for the high unit consumption are that: most of the existing thermal power plants are fuelled by coal, while most of these coal-fired plants utilize technologies and equipment typical of the 1950s and 1960s. Only a few of the plants utilize modern, highly efficient technologies. At the end of 1990, the Chinese generating plants of greater than 125 MW capacity that operated at higher pressure and efficiency constituted only 47 per cent of the total installed thermal generating capacity. Generally, auxiliary equipment efficiency is also lower and thus the internal electricity consumption is higher, at 8.22 per cent in 1990.
- According to expert forecasts, tables XI.9 and X.10 present the development trend of China's electric power industry. What should be indicated is that this forecast is based on a low rate of increase. During the 30-year period 1990-2020, the annual average rate of increase in installed capacity for thermal power generation will be 5.55 per cent, while during the 1990s, it will be 8 per cent.

4. Forecast for primary energy supply

According to the forecast results of end-use energy demand, taking into account the consumption arising from energy production, transport and distribution, the primary energy demand can be derived. After considering domestic output and import, the scenarios for primary energy supply, which are shown in table XI.11, can be obtained.

Table XI.11 shows that the primary commercial energy demand in 2000-2010 and 2020 will be about 1.5, 2.0 and 2.5 billion tons of standard coal equivalent (Gtce) respectively; coal demand will be 1.5, 2.0 and 2.5 Gt respectively, crude oil demand will be 0.2, 0.28, and 0.35 Gt, and natural gas demand will be 30, 60, and 120 billion (G) cubic meters. The share of coal in primary energy will decrease by 10 per cent during the 30-year period, and the share of natural gas, hydropower, and nuclear power will increase gradually.

I. CHALLENGES IN CHINA'S ENERGY DEVELOPMENT

China's modernization faces huge pressure in terms of population, available resources and the environment. Energy is closely related to the three restricting factors.

- The population is too high. As of February 1995, the population had reached 1.2 billion. More than half of the population's education level was limited to primary school or even lower. Excess population and low educational levels are the long-term and most important restricting factor in resolving China's energy problems. At present, China's primary energy consumption has ranked second in the world, but the per capita figure is very low. The per capita commercial energy consumption was 1,024 kg of standard coal equivalent (kgce) in 1994, which was only 50 per cent of the world average. Household per capita electricity consumption was 73 kWh, only equivalent to 2.2 per cent of the figure in the United States. Moreover, up to now, there are still 100 million people in China who have no access to electricity.
- Per capita energy resources are insufficient. China has an abundance of many kinds of energy resources but, on a per capita basis, this is relatively insufficient. The total coal resources amount to 4,000 Gt in the 1,500 metre depth range, but under the current technological and economic conditions, the recoverable reserves only amount to 114.5 Gt. The per capita figure is only equivalent to half of the world average. According to data from *1995 World Energy Statistic Review*, which was produced by the British Petroleum Corporation, by the end of 1994 the undeveloped demonstrated reserves of petroleum amounted to 3.3 Gt, making the per capita amount only 2.75 tons, equivalent to only 11 per cent of the world average. Relatively insufficient per capita energy resources, especially of petroleum, is an important restricting factor for the society and economic development of China.
- The ecological environment is deteriorating. The major energy and environment problems of China are atmospheric pollution in the cities, caused by large quantities of coal combustion and ecological damage caused by over-consumption of biomass in rural areas. China is one of the few countries in which coal plays so large a role in the energy mix. It is also the largest coal consumer in the world. Its coal consumption in 1994 amounted to 26.6 per cent of the world coal consumption. Nationwide (not including town and village enterprises), SO_2 emissions amounted to 18.25 Mt and total suspended particulate (TSP) emissions amounted to 14.14 Mt. Compared with 1990, this represents increases of 12.2 and 6.8 per cent respectively. Additionally, as greenhouse gas emissions from China have been ranked third in the world, it is also necessary to adopt some measures for controlling the rapid increase of CO_2 emissions.

J. POLICY OPTION FOR ENERGY DEVELOPMENT

1. Intensification of energy conservation

Adherence to the guideline that importance should be attached to both the exploitation and conservation of energy resources, while priority should be given to conservation, is important.

- Develop rational economy industry policies, advance adjustment of both the industry structure and the product structure, increase the proportion of the third industry in the national economy, and optimize the product structure.

- Enhance legislation in energy conservation, introduce the Energy Conservation Law as early as possible, and improve supervision of implementation.
- Improve the consumption structure of end energy, increase the proportion of electric power in energy usage as well as that of coal used for electricity generation in total coal consumption. It is initially scheduled that during the ninth five-year period, some 80 per cent of additional coal demand will be from electricity production, and by 2000 the proportion of coal usage for electricity generation to total coal consumption volume will increase from 25 per cent in 1990 to nearly 40 per cent. The proportion of washed coal increases from less than 20 per cent in 1990 to more than 30 per cent in 2000, and it is expected that by 2010 all coal conveyed out will be washed.
- With regard to the economic measures taken for the realization of energy conservation objectives, such economic benefits as preferential taxation, price subsidies and preferential loans (interest discount) etc., will be available for the production and use of energy-efficient products as well as the implementation of energy-efficient projects. To promote quick innovation of primary energy consumption equipment, an accelerative depreciation policy will be taken into account.
- Appropriate administrative measures will be taken to limit the export of high energy consumption products.

2. Diversification of financing and increase of input in energy construction

- The State will favour investment policies to the energy industry, diversify the fund-raising channel, and increase the proportion of investment in energy construction to national infrastructure construction investment. Loans provided by the State in terms of relevant policies will be allocated preferentially to national key energy construction projects, and special attention will be paid to the central and western regions.
- The initiative of local governments in energy project construction must be brought into full play. Local energy projects will mainly be financed and constructed by local governments in accordance with national overall arrangement and planning.
- The State encourages all walks of life, collectively and privately included, to invest in and set-up energy enterprises.
- Energy corporations, large and medium backbone enterprises, upon formal approval of the government, will be entitled to raise funds for energy construction both at home and abroad, including the issue of shares and bonds and becoming shareholders by assets input as equity etc.
- The utilization of foreign capital, funds of international financial organizations as well as government loans will be directed to the energy sector. The State encourages and attracts foreign capital to invest in energy construction directly.

3. Promotion of interregional cooperation in energy undertakings

To exploit and distribute energy resources rationally, the State should encourage interregional cooperation in energy undertakings.

- Provinces (municipalities, districts) short of energy, in the light of national industry arrangement policies and regardless of the region limit, may invest and run coal mines (joint ventures included) in coal reserve-abundent areas, and the transport of coal produced in this way should be arranged preferentially.
- The State encourages cooperation between localities or other sectors and the oil sector to exploit small and medium oil and gas fields.
- The State also encourages regions with an electricity shortage to undertake the construction of power plants regardless of administrative limits and in the light of the national overall electric power construction layout. Power network dispatching should guarantee investment

parties to obtain due electric power and electricity specified in agreements (contracts). The measures mentioned above will be protected by relevant laws.

4. Acceleration of operation mechanism transfer and injection of vigour into energy enterprises

- Regardless of region and sector limits, the establishment of corporations integrating coal, electric power and transport businesses will be encouraged to make best use of the advantages and bypass the disadvantages, realize mutual supplementation of the advantages, and improve the benefits of large-scale economy.

- An energy enterprise should hold a key business with the possibility of other diversified businesses being explored so as to enhance the ability to bear market risks and improve economic benefits.

5. Adjustment of energy prices

- Currently, in general, China's crude oil price is still low for several reasons. First, most of China's backbone oil fields have already entered the middle and later stages of extraction with production costs rising rapidly. Second, China's oil price level is simply equivalent to 60-70 per cent or so of the international market oil price. Third, as far as the price relations between crude oil and oil products are concerned, the price ratio is usually 0.7 or so, but in China the ratio is about 0.4, obviously low. It is expected that China's crude oil price will approach that in the international market by 2000.

- China's current coal price level is also low. This may be explained by the following factors. First, the coal price is considered to be low compared with production costs and expenses irrelevant to business. Second, price ratios are low between coal and such alternative energy as coke-oven gas, LPG, heavy oil, natural gas etc. Third, China's coal price is also low compared with the international market coal price. In 1994, the price of coal for power stations was $25/ton in China, while it was $40, $35 and $34 in the United States, Australia and Poland, respectively. Fourth, the price of coal for electricity production is not deregulated yet; it is not only lower than the average coal prices, but also lower than the price of coal for other sectors. In 1995, the average price of commercial coal produced by state-owned key mines was 140.44 RMB/ton, while the price of coal for power generation was 105.81 RMB/ton.

- By the end of 1994, China's electricity prices for industrial and residential use were 0.25 RMB and 0.23 RMB per kWh, respectively, simply equivalent to 42 and 21 per cent of the worldwide average; but prices of fuels for power generation reached about 70 per cent of the global average level in China, and the electricity price level is relatively low. China's electricity pricing mainly takes into consideration such factors as cost of fuel, transport etc., which are necessary for simple reproduction. However, this pricing approach fails to raise enough funds for expanded reproduction. It is thus necessary to adjust electricity prices processingly.

It is understood that during the ninth five-year period adjustment of prices will favour the energy industry.

6. Orientation to international energy markets and full utilization of international resources

- From a long-term point of view, the production of domestic high-quality energy sources, e.g. oil and natural gas, will fail to meet the domestic needs. Thus, on the one hand, exploitation of domestic energy sources should be accerlated; on the other hand, flexible energy import and export policies should be adopted for utilization of international markets to adjust fluctuation of domestic demands and supply in coal, oil and natural gas. Efforts should be made to attract overseas investment in China's energy industry. Meanwhile, its energy enterprises should participate positively in the exploitation of international energy resources, including technology and labour services, and enhance competitive power in international competition.

As for the energy import strategy, the import of natural gas through pipelines, which is cleaner and cheaper than oil, is more rational than the import of oil. A scheme to be considered is that natural gas be exploited in neighbouring nations and conveyed into China by means of pipelines. As far as resource exploitation conditions are concerned, there are rich oil and gas reserves in the east Siberian region of the Russian Federation, and one possibility is to exploit Yakucike gas field, 1,500 km away from Chinese territory, and convey natural gas in large quantities to China's northern region. Moreover, along with the construction of pipelines carrying oil from west (Xingjiang) to east, importing oil and natural gas from some Central Asian nations should also be considered.

- China will establish a national energy strategic reserve system gradually to guarantee stable energy supply in case of dramatic fluctuations in international oil prices.

7. Special attention to the construction of several strategic projects

- *Construction of a railway transport passage with high speed and large flow between "three west" coal bases and eastern harbours.* As a primary coal supply region of China, it is expected that the transport volume from this region to other part of China will top about 400 million tons per year for coal by 2000, and will further increase by 2010. The transport capacity of the Daqin Line will reach over 100 million tons annually by the end of this century, while the second passage, from Shenmu to Huanghua Harbour, is one of the key projects affecting China's overall energy supply around the year 2000, the construction of which should be accelerated.

- *Construction of western oil pipelines carrying oil to the eastern part of China when conditions are ripe.* Western China will be the hope of China's oil industry after 2000, and the eastward pipeline project will be of great importance owing to the long distance from the western to eastern main consumption centres (some 3,000 km away from Luoyang). It is estimated that by 2000 or so, exploitation of the three large oil fields in Xinjiang will have made significant progress, and oil output will have increased dramatically. If the oil transport volume reaches 20 million tons per year, the construction of the western oil pipelines will be economically beneficial. What should be done now is to enhance the survey, design and demonstration of the pipelines.

- *Promotion of electricity transmission from west to east.* To meet the needs of constructing pit mouse power stations in the western region and large-scale hydropower bases in the south-western region, and transmitting electricity eastwards, the project of electricity transmission from west to east should be scheduled properly. The State should promote and coordinate cooperation between the eastern and western regions in electricity undertakings, and construct long-distance electricity transmission lines across provinces and regions.

8. Acceleration of energy commercialization in rural areas

Currently, in the rural areas of China, both energy consumption intensity and utilization efficiency are relatively low, and the use of a large quantity of biomass energy has resulted in ecological and environmental destruction. Therefore, acceleration of rural energy construction is also one of the important tasks of China's overall energy construction. During the ninth five-year period, rural energy construction will mainly include acceleration of energy commercialization, further popularization of firewood or coal-saving stoves with high thermal efficiency, implementation of pilot projects on residential briquette, formation of new industries and improvement of the service system. Rural residential energy demands should be solved properly around 2000, and focus should be placed on the issues of counties and regions without electricity supply. Rural electrification should be realized progressively.

9. Acceleration of progress in science and technology

The strategic focus in developing energy science and technology within this century will be on:

- Research on the exploration and exploitation technology of coal bed methane.
- Development of thermal power units with high capacity, parameters and efficiency as well as power units with super-critical parameters, development of 500 kV and upwards superhigh voltage electricity transmission and transforming technology, improvement of the automatic level of power network dispatching, and development of 500-700 MW large-scale hydro turbo-generators.
- Technology improving the recovery efficiency of aged eastern oil fields which are entering the later stage of extraction, breakthrough in construction of western oil transport pipelines and technology of offshore oil and gas collection and conveyance.
- With regard to nuclear power, the development and application of 600 MW presurized water reactors is the current focus, and basic research on 1,000 MW-level nuclear facilities and other types of reactors will be launched around 2000.
- The development is needed of energy-related environment technology, including mainly such economic and practicable clean-coal technologies as coal washing and processing, de-ashing, desulphurization, low pollution combustion and desulphurization of flue gas so as to reduce environmental pollution owing to the exploitation and utilization of coal.
- Development of rural energy, energy conservation technology as well as energy comprehensive utilization technology: with focus on electricity saving, new technology for buildings and energy efficient processes will be developed. Enhancement of demonstration activities of new energy and renewable energy, e.g. gasification of biomass, liquefaction technology, high efficient photovoltaic cells, large-scale wind power generation, and high efficient energy storage technology etc. Above all, the conversion of scientific achievements into productivity should be vigorously promoted.

Table XI.1 Energy production in China, 1949-1994

Year	*Total (Mtce)*	*Coal (Mt)*	*Oil (Mt)*	*Natural gas (Gm^3)*	*Electricity generation (TWh)*	
					Total	*Hydropower*
1949	23.71	32.00	0.12	0.007	4.30	0.70
1952	48.71	66.00	0.44	0.008	7.30	1.30
1957	98.61	131.00	1.46	0.07	19.30	4.80
1962	171.85	220.00	5.75	1.21	45.80	9.00
1965	188.24	232.00	11.31	1.10	67.60	10.40
1970	309.90	354.00	30.65	2.87	115.90	20.50
1975	487.54	482.00	77.06	8.85	195.80	47.60
1980	637.35	620.00	105.95	14.27	300.60	58.20
1985	855.46	872.00	124.90	12.93	410.70	92.40
1990	1 039.22	1 080.00	138.31	15.30	621.20	126.70
1994	1 187.29	1 239.90	146.08	17.56	928.10	168.10

Source: *China Statistical Yearbook, 1995.*

Table XI.2 Primary energy consumption mix in China, 1949-1994

Year	Total (Mtce)	Energy consumption mix (percentage)			
		Coal	Oil	Natural gas	Hydropower
1953	54.11	94.33	3.81	0.02	1.84
1957	96.11	92.32	4.59	0.08	3.01
1962	165.40	89.23	6.61	0.93	3.23
1965	189.01	86.45	10.27	0.63	2.65
1970	292.91	80.89	14.67	0.92	3.52
1975	454.25	71.85	21.07	2.51	4.57
1980	602.75	72.15	20.76	3.10	3.99
1985	770.20	75.92	17.02	2.23	4.83
1990	987.03	76.20	16.60	2.10	5.10
1994	1 227.37	75.00	17.40	1.90	5.70

Source: *China Statistical Yearbook, 1995.*

Table XI.3 Primary energy consumption by sector and mix

	1980		1990		1994	
	Mtce	Per cent	Mtce	Per cent	Mtce	Per cent
Total end energy consumption	602.75	100.00	987.03	100.00	1 227.37	100.00
1. Production sectors	480.55	79.70	794.30	80.47	1 017.81	82.93
A. Agriculture	46.92	7.80	48.52	4.92	51.05	4.16
B. Industry	389.86	64.70	675.78	68.47	878.55	71.58
C. Construction	9.57	1.60	12.13	1.23	13.49	1.10
D. Transport and communications	29.02	4.80	45.41	4.60	56.25	4.58
F. Commercial	5.18	0.90	12.47	1.26	18.47	1.51
2. Non-Production Sectors	12.05	2.00	34.73	3.52	55.43	4.51
3. Household	110.15	18.30	158.00	16.01	154.13	12.56

Source: *China Statistical Yearbook,* 1995 and 1991.

Table XI.4 Energy export and import in China, 1980-1993

(Unit: Mt)

		1980	1991	1992	1993	1994	1995
Crude oil	Export	13.31	22.60	21.51	19.43	18.55	18.85
	Import	0.37	5.97	11.36	15.67	12.35	17.09
Oil products	Export	4.20	6.82	5.39	3.72	3.79	4.14
	Import	0.46	5.91	7.68	17.29	12.89	14.40
Coal	Export	6.32	20.10	20.19	19.81	24.30	28.60
	Import	1.99	1.37	2.00	1.43	1.22	1.20

Source: *China Customs Statistical Yearbook,* 1996.

Table XI.5 Rural energy consumption and mix in China

Year		Total		Production use		Household use	
		Mtce	Per cent	Mtce	Per cent	Mtce	Per cent
1980	Rural energy consumption	329.50	100.00	67.80	100.00	261.70	100.00
	1. Commercial energy	99.50	30.20	58.60	86.40	41.00	15.70
	a. Coal	65.00	19.70	27.90	41.20	37.10	14.20
	b. Electricity	19.20	5.90	16.60	24.50	2.70	1.00
	c. Oil products	15.30	4.60	14.00	20.70	1.30	0.50
	2. Non-commercial energy	230.00	69.80	9.20	13.60	220.80	84.30
	a. Straw					117.00	44.70
	b. Firewood					103.80	39.60
1990	Rural energy consumption	538.60	100.00	208.00	100.00	336.80	100.00
	1. Commercial energy	275.60	51.20	208.00	100.00	73.80	21.90
	a. Coal	214.10	39.80	149.80	72.00	64.30	19.00
	b. Electricity	33.80	6.30	31.70	15.20	8.30	2.50
	c. Oil products	27.70	5.10	26.50	12.80	1.20	0.40
	2. Non-commercial energy	263.00	48.80			263.00	78.10
	a. Straw					131.60	39.10
	b. Firewood					131.40	39.00
1994	Rural energy consumption	615.20	100.00	273.90		341.30	100.00
	1. Commercial energy	367.55	59.70	257.10		110.35	32.30
	a. Coal	262.80	42.70	169.30		93.50	27.40
	b. Electricity	67.60	11.00	52.35		15.25	4.40
	c. Oil products	37.05	6.00	35.45		1.60	0.50
	2. Non-commercial energy	247.85	40.30	16.80		230.95	67.70
	a. Straw	137.45	22.40	0.00		137.45	40.30
	b. Firewood	110.30	17.90	16.80		93.50	27.40

Sources: *China Energy Annual Review, 1995; and China Energy, 1992.*

Table XI.6 Forecast on economic development in China

		Total	Agriculture	Industry	Construction	Transport	Commercial	Non-production sector
1990	GNP (10^9 RMB)	1 767.60	502.40	698.10	84.80	95.60	94.40	291.80
	Mix (%)	100.00	28.40	39.50	4.80	5.41	5.34	16.50
2000	GNP (10^9 RMB)	4 184.60	770.00	1 667.90	219.90	248.00	295.80	973.20
	Mix (%)	100.00	18.40	39.90	5.26	5.93	7.07	23.30
	Increase rate (%)	9.00	4.60	9.10	10.00	10.00	12.10	12.80
2010	GNP (10^9 RMB)	8 624.60	1 052.20	3 285.90	453.40	511.40	759.60	2 567.80
	Mix (%)	100.00	12.20	38.10	5.26	5.93	8.81	29.80
	Increase rate (%)	7.50	3.17	7.00	7.50	7.50	10.00	10.00
2020	GNP (10^9 RMB)	15 445.30	1 343.70	5 514.00	812.40	917.40	1 556.00	5 297.70
	Mix (%)	100.00	8.70	35.70	5.26	5.94	10.10	34.30
	Increase rate (%)	6.00	2.48	5.30	6.00	6.00	7.40	7.50

Source: Data for 1990 is from *China Statistical Yearbook, 1994.*

Table XI.7 China population increase scenarios

(Unit: population-10^8)

	1990		2000			2010			2020		
	Population	Share (%)	Population	Share (%)	Growth rate (%)	Population	Share (%)	Growth rate (%)	Population	Share (%)	Growth rate (%)
Nationwide	11.43	100.00	12.94	100.00	12.50	13.90	100.00	7.20	14.50	100.00	4.20
City	3.02	26.40	4.06	31.40		5.20	37.40		6.50	44.80	
Rural	8.41	73.60	8.88	68.60		8.70	62.60		8.00	55.20	
Persons/household	4.20			3.86			3.61			3.37	

Table XI.8 Forecast results: final energy demand and mix

		1990		2000		2010		2020	
Type	Unit	Demand	Share (%)	Demand	Share (%)	Demand	Share (%)	Demand	Share (%)
Coal	Mt	530.98	33.04	632.76	27.85	771.59	24.00	715.71	19.97
Crude oil	Mt	3.87	0.48	2.32	0.20	2.81	0.19	3.09	0.17
Natural gas	100 Mm^3	147.89	1.71	268.20	2.20	537.74	3.38	995.19	5.17
Electricity	100 GWh	5 182.40	17.70	11 232.50	24.92	19 413.94	30.26	28 246.88	35.30
Oil products	Mt	88.11	11.29	157.16	14.25	229.67	15.95	299.84	17.23
Biomass	Mtce	264.97	23.08	264.40	16.29	254.32	12.01	220.76	8.62
Others	Mtce	145.74	12.70	231.64	14.28	300.72	14.20	346.51	13.53
Total	**Mtce**	**1 147.98**	**100.00**	**1 622.63**	**100.00**	**2 117.46**	**100.00**	**2 560.36**	**100.00**

Table XI.9 Development trend of installed capacity of the China electric power industry

Electricity Generation mode	1990		2000		2010		2020	
	MW	Per cent	MW	Per cent	MW	Per cent	MW	Per cent
Thermal power	101 820	73.86	220 200	75.79	374 650	76.39	514 850	73.55
Hydropower	36 040	26.14	66 500	22.89	100 000	20.39	138 000	19.71
Nuclear energy	0	–	2 700	0.93	10 700	2.18	32 000	4.57
Wind energy	10	–	1 000	0.34	4 000	0.82	10 000	1.43
Geothermal energy	21	–	60	0.02	100	0.02	150	0.02
Solar energy	–	–	80	0.03	1 000	0.20	5 000	0.71
Total	**137 891**	**100.00**	**290 540**	**100.00**	**490 450**	**100.00**	**70 000**	**100.00**

Table XI.10 Forecast of electricity generation of the China electric power industry

Electricity Generation mode	1990		2000		2010		2020	
	TWh	Per cent	TWh	Per cent	TWh	Per cent	TWh	Per cent
Thermal power	495.05	79.64	1 044.53	78.48	1 788.72	78.81	2 447.56	75.51
Hydropower	126.47	20.34	266.36	20.01	400.54	17.65	552.75	17.05
Nuclear energy	–	–	17.56	1.32	69.59	3.07	208.11	6.42
Wind energy	–	–	2.00	0.15	7.99	0.35	19.98	0.62
Geothermal energy	0.10	0.02	0.23	0.02	0.38	0.02	0.56	0.02
Solar energy	–	–	0.20	0.02	2.50	0.10	12.49	0.38
Total	**621.62**	**100.00**	**1 330.88**	**100.00**	**2 269.72**	**100.00**	**3 241.45**	**100.00**

Table XI.11 Primary energy supply, 1990-2020

		Unit	1990		2000		2010		2020	
			Supply amount	Share (%)	Supply amount	Share (%)	Supply amount	Share (%)	Supply amount	Share (%)
Commercial		Mtce	1 041.92	79.54	1 505.45	84.79	2 045.58	88.62	2 544.86	91.61
Coal		100 Mt	10.83	74.25	15.00	71.23	19.63	68.53	22.77	63.91
		Mtce	773.58		1 072.45		1 401.84		1 626.23	
	Output	100 Mt	1.38		1.65		2.00		2.21	
		Mtce	197.69		235.79		285.80		314.38	
Petroleum	Import	100 Mt	0.00		0.38		0.84		1.34	
		Mtce	0.00		54.14		119.47		191.59	
	Supply	100 Mt	1.38	18.97	2.03	19.26	2.84	19.81	3.55	19.88
		Mtce	197.69		289.93		405.27		505.97	
	Output	100 Mm^3	157.74		300.15		499.25		798.80	
		Mtce	20.98		39.92		66.40		106.24	
Natural gas	Import	100 Mm^3	0.00		0.00		99.55		393.76	
		Mtce	0.00		0.00		13.24		52.37	
	Supply	100 Mm^3	157.74	2.01	300.15	2.65	598.80	3.89	1 192.56	6.23
		Mtce	20.98		39.92		79.64		158.61	
Hydropower		100 GWh	1 266.00	4.76	2 665.28	6.37	4 007.88	6.47	5 525.63	6.95
		Mtce	49.63		95.95		132.26		176.82	
Nuclear power		100 GWh	0.00		175.83	0.42	696.36	1.12	2 080.31	2.61
		Mtce	0.00		6.33		22.98		66.57	
Wind, geothermal and solar energy		100 GWh	1.02		24.17	0.06	108.79	0.18	330.31	0.42
		Mtce	1.04		0.87		3.59		10.57	
Sum		Mtce	1 041.92	100.00	1 505.45	100.00	2 045.58	100.00	2 544.86	100.00
Non-commercial energy (biomass)		Mtce	268.07	20.46	270.09	15.21	262.57	11.38	233.01	8.39
Total		**Mtce**	**1 309.99**	**100.00**	**1 775.54**	**100.00**	**2 308.15**	**100.00**	**2 777.87**	**100.00**

XII. ENERGY INFRASTRUCTURE: INDIA*

The development of infrastructure is crucial to India's growth strategy. Despite an extensive infrastructure, which in several areas is among the largest in the world, there is considerable need for expanding facilities and improving quality. The size of the country, the acceleration in the economic growth and the need for modernization have created an urgent need for massive investments in infrastructure. Indeed, few countries in the world are comparable to India in terms of investment requirements. The growth opportunities that India offers for investments in infrastructure, either in the power, the hydrocarbon sector, telecommunications, or the transport sector, are indeed immense.

India is passing through a critical phase. The economic activities in the country are accelerating and the results are there for every one to see. It has achieved a GDP rate of growth of over 5.8 per cent during the eighth plan period (1992-1997), and is expected to achieve a growth rate of over 7 per cent during the ninth five-year plan (1997-2002). However, in order to achieve the targeted growth rate, very dependable and efficient infrastructural support is needed. Power, being the basic input for almost all economic activities, calls for special attention, particularly in view of the fact that of late the power supply has not been keeping pace with the demand and shortages have reached a level where the lack of electricity has started choking the economy – a situation the country can ill afford at this juncture.

From time immemorial we are being told that energy is life. The expression, probably, is more appropriate today than ever before. The level of energy consumption signifies not just the level of economic development but also aptly reflects the way people live in a particular country and their standard of living. We all know the energy consumption level in our country is alarmingly low. Against the per capita world average of over 1,500 kgoe, the per capita primary energy consumption in India is only about 250 kgoe. The disparity in per capita energy consumption in urban and rural areas in the country is also very glaring. For all of us associated in one way or the other with the energy sector, it becomes our prime responsibility to ensure development of the most cost-effective and sustainable way of meeting this basic need to the people.

Electricity is the most convenient of all forms of commercial energy and has rightly emerged as the most crucial input for sustaining the process of economic development. Against its many unique advantages, however, it suffers from at least two serious shortcomings. First, it is one of the most expensive forms of commercial energy, in terms of both capital and operating costs and second, being a secondary source of energy, its generation has certain environmental, ecological, social and economic implications for the exploitation of the primary energy sources such as coal, petroleum, water, fissile materials etc. The challenge thus facing us is how best to go about developing this vitally important but expensive energy option in relation to primary sources so that the larger objective of higher generation compatible with the social and environmental objectives is achieved. Central to this problem is the adoption of an energy strategy for the future that can fuel economic growth and yet do so at relatively lower financial and environmental costs.

It is in this context that today's decision makers are faced with many critical choices. The need for an optimal energy mix is only one of the decisions that have to be made, but nevertheless an extremely important one. The growing dependence on electricity as the source of energy has greatly increased the public awareness of the energy problems and caused people to demand solutions that provide not only a cheap but also safe and secure supply of electricity. Opinions vary on which form of energy source should be given precedence over others to produce electricity, but all tend to agree that a quantum jump in installed capacity in the short, medium and the long run is urgently required to avoid an energy crisis.

The primary energy resources of power generation available in the country are hydropower, fossil fuels, namely coal and lignite, oil and natural gas and nuclear energy. Some other non-conventional and renewable sources of energy, such as fuelwood, biomass, tidal, solar, wind and geothermal energy, are also available but they are in the nascent stage of commercial exploitation in the country. The

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conventional resources are not evenly distributed over various regions/states in the country. However, an interesting feature of distribution of energy resources in the country is that almost every power region in the country has been bestowed by nature with one or the other form of commercially exploitable energy resource. While the eastern and central regions are rich in coal deposits, the southern region has large lignite deposits along with hydroelectric potential and some natural gas and oil reserves. The northern and north-eastern regions have huge hydroelectric potential. The western region has substantial deposits of power grade coal along with large deposits of hydrocarbon resources. The power generation capacity in the country, so far, has been predominantly through coal-based generation or hydel generation. It is thus natural that in the foreseeable future, hydropower as a renewable source and fossil fuels such as coal and lignite would remain the main sources for power generation in the country, duly supported by natural gas and oil to some extent. The share of nuclear power is also expected to increase appreciably in the future, but may not be the mainstay of the energy generation. The details regarding various energy resources available in the country for power generation are given in table XII.1.

Table XII.1 Energy sources available for power generation

Type	*Potential*
1. Hydro (conventional)	84 000 MW at 60 per cent load factor (Untapped potential, 80 per cent)
2. Hydro (pumped storage)	94 000 MW
3. Coal reserves	186 billion tons
4. Lignite reserves	28 billion tons
5. Crude oil	728 million tons
6. Natural gas	686 billion cubic metres
7. Uranium	6 700 tons
8. Thorium	363 000 tons
9. Non-conventional sources	
Biomass	6 000 MW
Wind energy	10 000 MW
Solar	5 000 MW

Rapid capacity addition is needed to meet the growing demand for electricity. Considering the energy resources available in the country, it would be necessary either to resort to large-scale import of fuels, straining the economy, or to augment exponentially the indigenous coal production and transport infrastructure. On the supply side, the other possible alternative could be fuel substitution for power generation, particularly in those regions of the country where economically exploitable reserves of conventional fuel for power generation, such as coal and petroleum products, are not available.

The analysis of the past few decades clearly shows that the use of coal and, to some extent, gas, as the principal source of energy has been increasing more than proportionately. In 1996/97, for instance, some 75 per cent of the total energy generation came from coal and gas. The hydel-thermal mix in the installed capacity, which was as high as 53 per cent in the mid-1960s, is now only around 26 per cent. Coal is the most abundant fossil fuel resource. Naturally, the reliance on its use has been relatively high. However, this heavy reliance of the power sector on coal has had a number of implications. The most visible one, of course, is the deterioration in air quality, particularly in the vicinity of coal mines and power stations. In addition, the movement of a very large quantity of high ash-carrying coal over distances frequently exceeding a thousand km has placed a serious strain on the transport system of the country. Predictably, this over-dependence on coal also puts considerable pressure on coal-mining activity. Further, the high ash content of most of the Indian coal has reduced the operating efficiency of the power plants besides increasing the operating costs and shut-down time of plant and equipment, the generation of millions of tons of ash is an environmental hazard and requires disposal. The rapid expansion in coal use, primarily for electricity generation, is perhaps the largest source of the additions to the greenhouse gas emissions (mainly carbon dioxide) in India. The emissions of CO_2 have increased considerably over the years. Thus, in this context of environmental and infrastructure concerns, the view is gaining ground that coal, though important in the medium and short terms alone, will not solve the energy problem in India. Even if the coal industry can achieve its difficult goal of tripling production in another 10 years, and railway infrastructure is able to undergo a revolutionary change, the task of capacity addition of over 100,000 MW cannot be met by coal-based thermal units. Furthermore, looking at the long term, perhaps in the second quarter of the next century, when worldwide reserves of oil and natural gas approach depletion, the coal would have to be mined from much deeper depths. Seeking alternatives from now onwards is inescapable. Despite the possible reduction in capacity addition required through efficiency improvement measures, reduction in transmission and distribution losses and improving end-use efficiency, there is very little doubt that very large additions to the electricity generation capacity will be required in India during the next few decades.

Energy conservation methods can surely help to a certain extent to reduce the shortages and, therefore, these have been accorded very high priority. Higher productivity in generation and an efficient energy conservation programme is vital and its importance has been well recognized by the Government. Higher plant load factor (PLF) and better demand management would translate into higher availability of power at a much cheaper cost. As a matter of fact, energy conservation has been identified as a very important component of the overall strategy adopted by the Government to improve the performance of the power sector. The Central Electricity Authority (CEA) has estimated that by the year 2006/07 (end of the tenth five-year plan), about 15,000 MW could be saved by energy conservation measures alone. Another 15,000 MW could be saved if demand management measures were taken up in real earnest. Thus, there is scope for saving about 30,000 MW by 2006/07 by way of energy conservation measures. This is a significant quantity and the country is committed to adopt measures to improve the productivity of the generation resources, both conventional and non-conventional, and at the same time save energy to plough back the benefits. We are equal concern about the high transmission and distribution losses in the country, which are of the order of about 20 per cent, and happen to be among the highest in the world. We have initiated several steps to bring them down to a reasonable level.

In order to bring about all-round development in the performance of the power sector, an Action Plan was adopted at the State Power Minister's Conference held in 1993. The Action Plan covered both supply-side enhancement and demand-side management. It is heartening to note that these efforts have started bearing fruit and the PLF achieved last year was 64.4 per cent – an all-time high figure. Even the state utilities, with their old generating stations, registered an average PLF of over 60 per cent for the first time. A major renovation and modernization programme of the old power stations has also been launched. To ensure the availability of additional resources and the latest technology for renovation and modernization programmes, private investment has also been permitted in this area. Our approach has been to make all-out efforts to get the most out of the existing investments and at the same time mobilize public and private investments to augment generation and distribution so that the overall economic growth of the country is accelerated in the ninth and tenth plans.

To address the problems associated with the use of indigenous coal, particularly from the environmental point of view, the Government has recently revised the norms for the use of coal for power generation. It has now been decided to promote the use of beneficiated coal for power generation, particularly in rail-fed power projects. The norms for flue-gas emission are also being made more stringent, and coal-based power projects near ecologically sensitive areas and major cities are being discouraged. In parallel, efforts are being made to promote large power-generating capacity through pit-head plants. Such plants are expected to be quite effective in dealing with the coal transport issues as well as the environmental considerations. In addition to the efforts being made by the public sector utilities for the promotion of large-capacity pit-head power projects, the Government has also announced a policy for the development of mega power projects in the private sector.

Alternative energy sources are available, but are at present either undeveloped technologically or underutilized. Some of these energy sources are renewable, such as solar radiation, hydro, wind, tidal energy etc. Others are depletable, but relatively untapped, such as geothermal heat or synthetic fuels from coal or wastes. Hydel energy and nuclear energy, thus, seem to be a feasible alternative which hold the promise of contributing substantially to energy requirements. The undeveloped hydel potential in India is assessed to be over 64,000 MW at 60 per cent load factor. Most of these resources are concentrated in the northern and north-eastern regions. As most of these resources are yet to be translated into concrete projects which can be taken up for execution, if we look at the natural resources and the infrastructure available in the country, nuclear power can supplement the coal and hydrocarbon-based power generation in the country.

Reflecting the good correlation between electricity use and economic development, the demand for electricity in India has been growing rapidly in recent years. The installed capacity with the public utilities went up from a mere 1,300 MW at the time of independence to over 85,000 MW by the end of fiscal year 1996/97. Power generation increased from about 4 billion units in 1947 to nearly 395 billion units by the end of March 1997, an increase of nearly

100 times. Overall growth of the sector since 1947 is depicted in the table below:

Table XII.2 Power sector – An overview

	1947	*1997*
Installed capacity (MW)	1 362	85 000
Power generation (Billion units)	4.1	394.5
Villages electrified	3 000 (approximate)	504 064 (approximately 86 per cent of total villages)
Agricultural pumps energized	21 000	11 426 250
Per capita electricity consumption (kW/hr)	15	320 (pertains to 1994/95)

However, in spite of this enormous growth in electricity generation capacity, power shortages are a common phenomenon in almost all states throughout the country. The shortfall in aggregate electrical supply during the last financial year, i.e. 1996/97, for all of India, has been estimated at 12 per cent for energy and about 18 per cent for peaking power. The per capita consumption of electricity in the country, at approximately 320 per kWh, is one of the lowest in the world. There are, however, significant variations across regions.

Table XII.3 Per capita consumption of electricity by region (kW/hr)

Year	*Northern region*	*Western region*	*Southern region*	*Eastern region*	*North-eastern region*	*All India*
1985/86	173	259	186	115	50	178
1994/95	303	465	368	179	102	320

To meet the needs of our growing population and increase in economic activity, the demand for energy is likely to multiply. It has been projected that by the year 2006/07, the demand would be more than double compared with what it is today. If this happens, the primary energy required to produce electricity in that year will be three times that required today. The analysis carried out by CEA in 1991 on the perspective of power development up to 2006/07 showed that a minimum capacity addition of 142,000 MW was required in 15 years (1992-2007). This amounts to three times enhancement in the capacity addition programme as compared with what was achieved during the period 1979-1992. Considering the capital-intensive nature of the power industry, the requirement of financial resources is formidable. The ninth five-year plan for the country is still under formulation. The 15th Electric Power Survey Report assesses an energy requirement of 570 billion units and a peaking requirement of over 95,000 MW by the year 2001/02. In order to meet the demand for power, following the deterministic approach and after making due allowance for planned and forced outages, annual and capital overhaul, and taking into account the installed capacity at the end of the eighth plan, it is assessed that a capacity addition of around 57,000 MW would be required during the ninth plan period (1997-2002). The capacity addition requirements for the tenth five-year plan period (2002-2007) work out at around 45,000 MW. This implies that over a period of 10 years, that is, up to 2006/07, we need to add around one hundred thousand MW capacity to the system at an average rate of 10,000 MW per annum. It is assessed that with the capacity addition of the targeted capacity during the ninth plan, it would, by and large, be possible to meet the peaking and energy requirements of the country. It is estimated that this would require about $100 billion for power generation and for the matching transmission, distribution and rural electrification activities during the ninth plan period. The task indeed is enormous, considering the fact that the country was able to add only about 45,000 MW during the last 12 years.

Though the sector was never very "cash surplus", the severity of the economic crisis dawned upon us in the late 1980s when, owing to the paucity of resources with both state and central sector companies, the eighth plan programme had to be truncated from an estimated need-based requirement of 48,000 MW to about 30,500 MW. It was during this period that the Government initiated studies to ascertain the feasibility of expanding private sector company participation in the power sector to bring in additional resources. These studies culminated in the announcement of a comprehensive policy for private participation in 1991. In fact, realizing the crucial role expected to be played by the foreign investors in the future growth of the sector, in view of the limited resources that can be mobilized from within the country, the private power policy of the Government of India has been formulated to address adequately the issues related to foreign private investment in the sector. The policy, besides permitting up to 16 per cent return on equity and an additional return on equity at a rate of up to 0.7 per cent for every percentage point increase in PLF beyond 68.5 per cent, as an incentive for better plant performance to all the investors, also provides for foreign equity participation up to 100 per cent, protection against foreign exchange fluctuation for return on equity up to 16 per cent, and repatriation of profits without any export obligations etc.

Besides promoting conventional power projects, the private power policy of the Government of India comprehensively addresses other possibilities of augmenting power generation through improved productivity and efficiency, such as captive power and co-generation, renovation and modernization etc. In order to encourage captive, including co-generation power plants, guidelines have been issued for creating an institutional mechanism for the early clearance of such proposals and also to ensure effective measures such as purchasing or wheeling surplus power from such plants. It is expected that these measures will go a long way in meeting the immediate and long-term energy needs of the industrial sector and also in adding generation capacities in the country.

The response to the private power policy of the Government has been quite encouraging, and 128 expressions of interest have been registered amounting to an investment of over $75 billion and about 71,000 MW of installed capacity. These include about 50 proposals from foreign developers/investors for a total of nearly 38,000 MW capacity, involving an investment of over $42 billion. Techno-economic clearance of 20 projects for 11,878 MW has been accorded so far. In 17 power projects, for a total capacity of about 4,500 MW, construction work has already commenced and in seven of these projects units have already been commissioned and are in commercial operation. It is expected that many more projects will follow very soon. So far, 15 private power projects of varying capacities have achieved financial closure.

However, as we have gone along the learning curve, we have realized that one of the factors that hinders the flow of substantial private investment into the sector, in spite of a phenomenal initial response from the investor community, is the poor financial credibility of the State Electricity Boards (SEBs) and the state governments. The financial condition of most of the SEBs in India is not good, and as these are the ultimate buyers of power generated by the IPPs in most of the cases, the power purchase agreements signed by the SEBs with the IPPs are not bankable. In order to "kick start" the industry, the Government of India committed counter guarantees to initial eight fast-track power projects in the private sector. However, as the mechanism of project development through counter-guarantee was not sustainable, the Government decided not to offer counter-guarantees to any more projects. The Government is aware of the fact that, on a long-term basis, in order to make the power sector self-sustaining, it is essential to reform the SEBs and make them financially and commercially viable. Electricity is a subject in the concurrent list of the Constitution of India. The decision-making and implementation of power-related schemes involve both the central and the state governments. Traditionally, the policy guidelines and the statutory and organizational frameworks have been provided by the central government through the Indian Electricity Act, 1910 and the Electricity (Supply) Act, 1948. The state governments have been primarily responsible for the generation, transmission and distribution of the power to the ultimate consumers. Considering that the power sector reforms cannot be carried out without the involvement of the state governments, efforts have been made to encourage states to initiate actions for SEB restructuring and tariff rationalization as an unremunerative retail tariff structure is considered to be the root cause of the problems faced by the SEBs. The issue of SEB reform is high on the agenda of the Government and the matter has been taken up for discussion at the highest decision-making forum in the country. There was an unanimous resolution of the Chief Minister's Conference. The Chief Ministers of various states have agreed to time-bound reform and restructuring of SEBs and a Common Minimum National Action Plan was evolved and adopted by all the states and central government seeking to set-up a new institutional mechanism of independent central and state regulatory commissions, rationalize tariffs, promote efficiency parameters, delegate greater powers for project clearance to the state etc. Steps have also been taken to set-up a Central Electricity Regulatory Commission and state electricity regulatory commissions at the state level. It is proposed to introduce a bill in the next session of parliament bringing in the necessary legislative changes in the Act. Meanwhile, the Orissa Reforms Act came into force with effect from 1 April 1996. Rajasthan and Haryana reform bills are expected shortly. The policy initiative taken by the Government has helped states such as Haryana, Uttar Pradesh, Andhra Pradesh, Bihar, Gujarat, Kerala, Karnataka, Madhya Pradesh and

Assam also to take the reform path. It has also been decided to open the transmission sector to the private sector for development. A bill to carry out the necessary changes in the existing provisions in the Act has been introduced and is currently under examination by the Government. The proposed ordinance permits licensees in the power transmission sector. The state government would now be empowered to grant licences for intra-state transmission and the central government for inter-state transmission. The licences can be issued in favour of 100 per cent public sector, 100 per cent private sector or joint sector companies. Once the bill is accepted, it would pave the way for private investment in the transmission sector.

Considering the various energy options available for power generation in the country, coupled with the vibrant private sector in the industrial field, a competent electricity generation, distribution and transmission equipment supply industry which has state-of-the-art technology, a vast pool of trained, skilled and industrial manpower with a capacity to absorb new management and technological expertise, as well as the willingness of the Government of India and the state governments to invite private investment for sectoral growth, there is no doubt whatsoever that the country will successfully address the energy-related issues in a most comprehensive manner. Though the policy for unrestricted private investment was announced only a couple of years ago, India is known for its entrepreneurial qualities and the private sector business has been flourishing here for centuries. Even in the power sector, private participation is not a novel concept. In fact, the power industry in India started its growth in the private environment and was predominantly in the private sector until independence. Even during the period when the sectoral growth was primarily entrusted to the public sector, there were private utilities operating in the country as licensees and these private companies were not just operating but were among the most profitable in the country.

XIII. ENERGY INFRASTRUCTURE AND PRICING POLICY IN THE ISLAMIC REPUBLIC OF IRAN*

BACKGROUND

1. Macroeconomic context

The Islamic Republic of Iran has an area of 1.648 million km^2, a population of 60 million and a 1995 GDP per capita of Rls 225,500. GDP per capita increased during the period of the first five-year plan (1989-1993) by 4.6 per cent annually. The country has substantial mineral resources and some of the largest hydrocarbon reserves in the world. The population of the Islamic Republic of Iran increased rapidly before the first five-year plan (3.2 per cent annually), but was controlled after the plan and reached 1.7 per cent in 1995. The GDP structure is shown in table XIII.1. The macroeconomic component provides inputs to the energy sector and is also a receiver of inputs from the energy sector.

Table XIII.1 Evolution of GDP, 1980-1995

(Percentage)

	1980	*1990*	*1995*
Agriculture	18	24	25
Industry, mining and construction	18	17	17
Energy	14	12	16
Services	52	48	41
Total	**100**	**100**	**100**

2. The energy sector and the macroeconomy

Oil was the key domestic fuel during the 1960s, 1970s and 1980s, but its most important role was as generator of export income and of surplus finance and this function will remain the preoccupation of energy policy during the implementation of the economic restructuring programme of the 1990s. Previously, annual crude oil production in the Islamic Republic of Iran fluctuated widely, reaching a peak of 6 mb/d in 1974, plummeting to 1.3 mb/d in 1981 and then increasing by the first five-year plan to 3.1 mb/d. The annual level of production is now no longer determined by production constraints, but is regulated by the OPEC production quota. This means that the exportable surplus of oil is determined (at least in the short run) by the domestic level of demand. The reduction in oil consumption by energy savings and by fuel substitution has therefore become the most important policy objective in the national energy policy.

In view of this background and because of its vast reserves, natural gas is destined to become the fuel of the future, replacing other fuel use wherever it is economic. Natural gas production started in 1966 for exports to the former Soviet Union, but already during the 1970s, its use in the Islamic Republic of Iran had started to be developed as well. The annual production of natural gas is about 46 billion cu m, of which one third is used in power production and the rest in the residential and industrial sectors. Gas exports to the former Soviet Union restarted in 1990 after a 10-year hiatus with an expected level of 3 billion cu m/year, but the break-up of the former Soviet Union led to a temporary breakdown of this export prospect.

The energy sector assists the economic development of the country and increases consumer welfare by covering the needs of energy of final consumers amounting to 584 million boe in 1995 by providing 85 per cent of export revenues; and by providing about 63 per cent of the government revenue (1995).

During the period 1992-1995, investments in the energy sector amounted to some 2.5 per cent of GDP, representing about 10 per cent of total investments and a third of public sector investments.

Table XIII.2 Energy sector and the economy, 1995

	Percentage of national total
GDP	-16
Export revenue	85
Employment	1
Investment	9
Government revenue	63

* Mohsen Bakhtiar, Head, Energy Economics Department, Ministry of Energy.

A. RESERVES

The primary resource base in the Islamic Republic of Iran is substantial and includes oil, natural gas, hydropower, coal and solar energy. The hydropower potential amounts to about 20,000 MW on the Karun and Karkheh Rivers alone. The present estimates of proven reserves of oil and natural gas for oil reserves amount to 88 billion barrels (about 10 per cent of the world total) and natural gas reserves to 20 trillion cubic metres (close to 15 per cent of the world total and the second largest in the world). At the rates of production planned for the medium term, the country's petroleum deposits could last 70 years and its natural gas deposits 300 years. The present estimates show that the proven reserves of coal are about 6.5 billion tons, of which 13 per cent of total reserves, and these reserves are mainly concentrated in the eastern, northern, north-western and south-western regions of the country. The coal reserves are abundant and may be extracted and used wisely for the economic development of the country in the future.

Table XIII.3 Proven reserves of fuels, 1995

	Proven (thousand mboe)	*Share (percent-age)*	*Production (annual)*	*Reserve/ produc-tion ratio*
Oil	88	37	1.4	62
Natural gas	121	50	0.4	426
Coal	32	13	–	–
Total	**241**	**100**	**1.7**	–

B. PRIMARY ENERGY SUPPLY

In 1995, the country's total primary energy supply was equal to 1,738.8 million barrels of oil equivalent, 82.4 per cent of which was from crude oil, 16.5 per cent from natural gas, 0.65 per cent from hydropower and the rest from coal and non-commercial fuels. In the last few years, taking into account the substitution of natural gas, the structure of internal energy production has undergone remarkable change and along with it, the natural gas share increased from 7.1 per cent in 1988 to 16.5 per cent in 1995, and the oil share was lowered from 91 to 81 per cent.

On the whole, from 1988 to 1995 the final demand structure of energy faced a decrease in oil and a considerable increase in the share of natural gas. In this period, the share of oil products in the final demand of energy decreased from 79.8 to 60.7 per cent and that of natural gas increased from 7.1 to 30 per cent.

C. ELECTRICITY GENERATION

According to statistics concerning the electricity generators from 1995, the total actual capacity of power plants under the management of the Ministry of Energy was 21,914 MW, 52.7 per cent of which came from steam power plants, 35.4 per cent from gas and combined cycle power plants, 9 per cent from hydropower and the rest from diesel generating stations. In that year, electricity generation showed an average increase of 5.9 per cent compared with 1994.

Table XIII.4 Primary energy supply and final energy consumption, 1967-1995

(Million barrels of oil equivalent)

	1967		*1988*		*1995*	
	Amount	*Share (%)*	*Amount*	*Share (%)*	*Amount*	*Share (%)*
Production	960	100	1 026	100	1 739	100
– Crude oil	948	99	933	91	1 433	81
– Natural gas	6	0.6	73	7	286	17
– Solid fuels	1	0.1	5	0.5	5	0.3
– Hydropower	1	0.1	11	1	11	0.6
– Non-commercial fuels	5	0.5	3	0.3	3	0.2
Imports of energy	0		69.5		29.4	
Exports of energy	893		682.5		1 001.2	
Total primary energy supply	74.8		402.2		752.4	
Transformation losses	21.4		70.8		168.5	
Total final energy consumption	53.4		331.4		583.9	

Table XIII.5 Installed capacity of power generation

	1988		1994		1995		Annual growth rate (1988-1995)
	Amount (MW)	Share (%)	Amount (MW)	Share (%)	Amount (MW)	Share (%)	
Steam	7 475	54.6	10 742	52.6	11 557	52.7	6.42
Combined cycle	–	–	3 175	15.6	3 916	17.8	–
Gas	3 489	25.5	3 785	18.5	3 830	17.5	1.30
Hydro	1 914	14	1 953	9.6	1 953	9	0.28
Diesel	803	5.9	758	3.7	658	3	-2.80
Total	**13 681**	**100**	**20 413**	**100**	**21 914**	**100**	**6.96**

In 1995, the power plants, including those under the management of the Ministry of Energy and heavy industries, generated 85 billion kWh of energy, showing the annual growth rate of 8.2 per cent during the period 1990-1995.

Table XIII.6 Electricity generation and energy per capita, 1978-1995

Year	Generation: Ministry of Energy	Generation: Others	Total	Energy per capita
1978	17 386	2 461	19 847	545
1988	43 775	3 825	47 600	916
1994	77 086	4 933	82 019	1 365
1995	80 044	4 925	84 949	1 388

D. THE STRUCTURE AND EVALUATION OF ENERGY DEMAND

1. The composition of demand

As concerns the fuel mix for final energy demand, table XIII.7 shows that the share of petroleum products amounted to 61 per cent in 1995, the share of natural gas to 30 per cent, of electricity to 7 per cent and of solid fuels to 2 per cent.

As is shown in the table, the share of petroleum products decreased from 80 to 61 per cent during the period 1988-1995 and the share of natural gas rose from 10 to 30 per cent.

As regards the sectoral consumption of final energy consumption, the table shows that the residential/commercial sector was the most important energy-consuming subsector during the period 1988-1995, accounting for more than a third of total consumption; the energy demand for transport amounted to more than one fourth of the total.

Table XIII.7 Final energy demand by fuel, 1988-1995

	1988		1995		Average annual growth rate (percentage)
	Amount (mboe)	Share (%)	Amount (mboe)	Share (%)	
Petroleum products	265	80	354	61	4
Natural gas	34	10	175	30	26
Electricity	23	7	43	7	9
Solid fuels	10	3	12	2	3
Total	**331**	**100**	**584**	**100**	**8**

Table XIII.8 Final energy demand by sector, 1988-1995

	1988		1995		Average annual growth rate (percentage)
	Amount (mboe)	Share (%)	Amount (mboe)	Share (%)	
Residential/ commercial	111	33	212	36	10
Industry	91	27	157	27	8
Transportation	83	25	137	23	7
Agriculture	27	8	31	5	2
Others	20	6	48	8	13
Total	**332**	**100**	**584**	**100**	**8**

In 1995 the energy consumption of the industrial sector was 156.8 mboe, 31 per cent of which came from oil products, 53.5 per cent from natural gas, 10 per cent from electricity and 5.6 per cent from solid fuels. So, in this sector, the share of oil products from 1988 to 1995 decreased from 69 to 31 per cent and the share of natural gas share rose from 17.1 to 53.5 per cent. In 1995, 13.5 per cent of oil products, 47.8 per cent of natural gas, 76.4 per cent of solid

Table XIII.9 Potential and target

Sector	*Recoverable potential, year 2005*			*Feasible targets, annual energy saving*		
	Fuels (thousand TOE)	*Electricity*		*Fuels (thousand TOE)*	*Electricity*	
		GWh	*MW*		*GWh*	*MW*
Residential, commercial, public	420	5 690	1 430	55	1 200	315
Industry	700	650	155	140	50	15
Transportation	1 020	0	0	155	0	0
Load management	0	1 700	430	0	370	100
Total	**2 140**	**8 040**	**2 015**	**350**	**1 620**	**430**

fuels and 37.6 per cent of electricity were consumed by this sector.

The success of the Government's oil substitution policy through the increased penetration of natural gas can be witnessed by the strong growth in demand of natural gas from 1988 onwards, when domestic consumption more than quadrupled. This kept the growth in the demand for oil relatively flat. Next to natural gas, electricity was the fastest growing fuel, and the only fuel that did not witness a fall in demand during any period in the 1980s.

2. Development in household energy demand

Household energy consumption shows the following general characteristics:

- Kerosene is the fuel of last choice. In rural areas which lack access to either natural gas or LPG, kerosene is used for both cooking and heating; if LPG is available, kerosene is used for heating only. In urban areas, kerosene is used for heating by households that lack access to natural gas. In addition, in the houses which have neither electricity nor gas, kerosene is used for making hot water as well.

- LPG is used for cooking only.

- Natural gas is used for cooking and for heating, including hot water heating.

- In households using natural gas, electricity is used for lighting and electrical appliances only. In households that have no access to natural gas, electricity is also used for heating during particularly cold winter days when there are kerosene shortages.

- Solid fuels are used in relatively isolated areas and by urban households for heating when there are severe shortages of hydrocarbon fuels.

E. RECOVERABLE ECONOMIC POTENTIAL

Evaluation of the energy conservation or substitution potential could be recovered in the period 2000-2005, considering the technical feasibility of measures and their economic profitability. This has the potential for the reduction of energy consumption at the end of the period, with respect to the trend of energy demand based on existing patterns if no action is undertaken.

F. ENERGY PRICING POLICY IN THE ISLAMIC REPUBLIC OF IRAN

The low energy prices in the Islamic Republic of Iran do not reflect economic costs. Further distortions exist in the tariff structures of most energy sources and in their relative prices. Price reform is a key policy element for achieving increased energy conservation and economic substitution.

Energy pricing policies in the Islamic Republic of Iran, need to address the following three main issues:

(1) Rapid increases in the domestic consumption of petroleum products may turn the country into a weak oil exporter after the year 2020. The Islamic Republic of Iran needs to promote greater efficiency of energy use and develop demand management.

(2) Energy pricing policies influence the behaviour of energy producers and consumers. There are policy trade-offs which need to be clearly addressed: energy subsidization may be desirable for equity reasons, but may discourage investment and resource development.

(3) Energy resources should be priced at their economic values. Greater reliance must be placed on economic principles, such as long-run marginal cost and efficiency pricing (shadow pricing), rather than relying on financial analysis alone.

1. Electricity tariffs

The procedure of the Ministry of Energy for determining the average tariff of electricity is based on the estimate of electricity available for sale and the revenue to be earned for meeting the planned capital and operating expenditure. Based on the average price so obtained, the rates to various types of consumers are worked out. The bulk supply tariff of the Iran Power Generation and Transmission Company (TAVANIR) for its sales to the distribution companies is heavily subsidized.

The residential tariff starts from free supply up to 40 kWh/month and ends with 170 rials/kWh for consumption above 1,100 units; the commercial tariff, with consumption up to 500 kWh/month, is charged at 40 rials; for consumption between 500 and 2,000 kWh/month the charge is 100 rials/kWh, and for consumption in excess, the rate is increased to 120 rials/kWh. The average prices in the category consumption are shown in table XIII.10.

Table XIII.10 Price of electricity by sector, 1995

(Rials/kWh)

Category	*Average price*	*Subsidy*
Residential	23	77
Commercial	83	17
Industry	59	41
General	42	58
Agriculture	5	95
Average	**41**	**59**

2. Natural gas tariffs

Natural gas is the premium fuel for substitution because of its abundance, its relatively low cost and its environmental qualities. Next to heavy fuel oil, natural gas is the lowest priced fuel in the Islamic Republic of Iran. What can be noted in the structure is the high relative difference between the tariffs charged to power plants and to industry. But the absolute difference in the tariff is small.

Table XIII.11 Natural gas tariffs, 1994

	Rials/m^3
Household	14
Commercial	17
Industry	20
Power plants	6

3. Prices of oil products

All prices of petroleum products are set below the level of international market prices. Yet, the Government has followed a policy of low prices for fuels delivered to the power plants and for kerosene. Fuel oil remains the lowest priced fuel, in spite of a 66 per cent increase in 1987 and a 150 per cent increase in 1990. In between the extremes are the prices charged for gasoline. These were subject to considerable price increases in the early 1980s, but experienced a fall in the market recently.

Table XIII.12 Price of petroleum products, 1996

	Rials/litre
Gasoline, regular	160
Gasoline unleaded	160
Gasoline, premium	220
Kerosene	30
Gas oil	30
Fuel oil	20

4. Impact of the pricing policy on the socio-economic situation of households and on social equity

The income elasticity of household energy demand is substantially less than 1, that is, the proportion of household income spent on household energy declines as income increases. Relatively speaking, an increase in the price of energy will have a larger negative impact on the socio-economic position of the poor than of the rich. Because of the low prices of household energy in the Islamic Republic of Iran, expenditure on energy by households amounts to

4 per cent or less of disposable income in all income categories, which is about one third to one fourth of "international standards".

5. Impact of the pricing policy on energy demand

That the low cost of energy increased the national demand for energy is obvious. But in addition it has some other indirect microeconomic consequences. In the agricultural sector, for example, because of the relative cheapness of electricity two tendencies can be noted. First, there is a tendency to replace diesel pumps and traditional systems of irrigation by electric pumps: second since no consideration needs to be taken of the cost of energy, there is an over-consumption of both scarce water resources resulting in ecological damage, and electricity, contributing to the 20 per cent annual growth in rural power consumption that took place during the 1980s.

6. Impact of the pricing policy on macroeconomics

As the real price of energy is increased gradually during the second five-year plan period, the price elasticity of demand (over a three- to four-year period) in the Islamic Republic of Iran may change from the insignificant (-0.01) to the rather important (-0.2), based on experience in other countries. For the period of the plan, this will mean that energy demand at the end of the period is unlikely to have fallen more than 5 per cent compared with the "business-as-usual" scenario. However, during the third five-year plan period, the impact will continue to be felt and will result in an estimated additional 15 per cent savings.

G. NON-PRICING POLICY

1. Elements of the strategy

A two-tiered approach is suggested, as non-pricing policy for increasing energy efficiency in the short term (next five years) and in the medium term (next 5-10 years) activities. The short term activities include:

- ❑ *Legislation, regulations and institutional arrangements:* government decisions and a legislative framework are needed for giving high priority to energy efficiency investments as against power expansion investments. A policy implementation framework also needs to be created.
- ❑ *Demand-side management action:* education and information campaigns can start rapidly. However, action should be well prepared by careful analysis of energy demand and consumer behaviour.
- ❑ *Apply existing rules such as the Building Code (use of better insulation, design, materials, and construction techniques)* to improve the energy efficiency of buildings through training for architects, engineers and technicians, and better enforcement;
- ❑ *Decisions on regulations and incentives (either monetary or non-monetary)* – which can promote greater efficiency in the production, transmission and use of energy.

The medium term activities include:

- ❑ *Household appliance standardization and labelling:* the Government should decide and make clear to manufacturers that standards are a major tool for developing quality and efficiency.
- ❑ *Consumer protection:* a consumer protection policy will be developed; the establishment of consumer protection organizations should be encouraged.
- ❑ *Load research and load management:* energy suppliers, especially power companies, should not only start load research, but also rapidly build up an energy-efficiency strategy based on information already available.
- ❑ *Performance monitoring* is important for learning to what extent the proposed strategy has achieved its stated and required objectives, which will require the formulation of performance targets.
- ❑ *Strengthening domestic R and D capacity* – both to facilitate adaptation to local conditions of imported technology and to attempt to develop new technology.

2. Legislation and institutional arrangements

According to studies made, the savings potential rate in the country in industry and other areas is about 20 to 35 per cent. Annually, this is equal to a capital of above 5 billion dollars. Every attempt to reduce waste of energy will be a step forward in the development and increase of the nation's wealth.

Taking these points into consideration, the second five-year plan (1995-1999) has specified a sub-law for this issue, in which it was stipulated that all energy-consuming factories establish an energy management department and carry out energy management programmes.

In the past few years, the Ministry of Energy has carried out the formation and organization of energy management in this field. In the lifetime of its programme, it has founded new organizations owing to the increase in its obligations. The Iran Energy Efficiency Organization (IEEO), was founded in April 1996 and began its activities in different fields. At present, IEEO is involved in energy auditing and management, training and awareness programmes in all energy-consuming branches.

3. Energy efficiency label

The sub-law of the second five-year plan, which has been formulated with the aim of achieving sustainable management and rational use of the energy of the country, stipulates that specific standards for energy efficiency in different systems and equipment be established and all users be obliged to follow these standards.

The design and placing of the efficiency labels is a step forward in informing the consumers as to the correct use and efficiency of various types of equipment. Therefore, each consumer in the country can make a contribution towards lowering the amount of energy used and the losses by choosing the most efficient equipment.

The efficiency label has different parts explaining the efficiency and energy usage and compliance with standards.

4. Energy audits

IEEO began its work on energy auditing with 20 manufacturing units, such as in the pharmaceutical, food, metal, chemical, cement, paper, glass, rubber and textile industries.

5. Information and training programmes

Changing the patterns of energy consumption at all social levels is the goal of an information programme in IEEO, which is accomplished by the media for all energy-consuming groups.

This programme has different sections:

- BEHSAMAN (Energy Efficiency Programme) Bulletin
- Technical booklets on energy management
- Films on energy management

H. CONCLUSIONS AND RECOMMENDATIONS

- The primary energy supply is dominated by oil products, which accounted for about 60 per cent of primary energy supply in 1995; natural gas came a clear second with 30 per cent. As regards the sectoral consumption of final energy consumption, the residential/commercial sector was the most important energy-consuming subsector in 1995, accounting for more than a third of total consumption.
- Since the present fuel prices are between 10 per cent (fuel oil) and 30 per cent (gasoline) of the economic cost of supply (export f.o.b. price plus costs of distribution for the fuels), the prices of fuels in real terms have to be raised 3 to 10 times in accordance with the pricing policy.
- The longstanding subsidization of domestic energy consumption has led to excessive, low-priority consumption, a habit of energy waste and a situation where the energy sector companies cannot even cover operating costs (let alone finance investments). Given the fact that the cost of supplying both oil and electricity is increasing, the practice of low energy prices is becoming even more costly and antithetical to the pursuit of efficiency of supply, optimal substitution in consumption and the minimization of the environmental impact of energy operations. The positive impact that this policy may have had on low-income groups is partly undone by the free rider effect for those groups that can pay higher prices, while the negative impact on the government budget and the allocation of resources is obvious.

- During the second five-year plan, 1994-1999, the Government intends to intensity the reform process by reducing subsidies to consumption and by implementing the commercialization and privatization policies that have scarcely started.

- The draft studies show that the potential economic energy savings during the period 1994-2005 are estimated to be at least 2 million TOE for fuels and about 8,040 GWh of electricity (or about 2,015 MW), most of which will be realized after 2000.

XIV. RECENT MOVES AROUND INDEPENDENT POWER PRODUCERS IN JAPAN*

INTRODUCTION

The electricity wholesale supply system was newly introduced under the latest amendment to the Electricity Utilities Industry Law in December 1995, in hopes of cutting high electricity rates in Japan, by introducing IPPs to the power generation market, at international levels. These waves of so-called deregulation of various industries, including electric utilities, were integrated into a general Economic Structural Reform Programme approved by a Cabinet meeting in December 1996. The present report aims to examine the results of Japan's first bidding for wholesale electricity supply, and consider future issues.

1. Results of first round of IPP bidding (fiscal year 1996)

(a) Twenty successful bidders to supply a total of 3,046.90 MW

Electric utilities announced the successful bidders in their competitive bidding for electricity wholesale supply held in fiscal year 1996. There were six such utilities, Hokkaido (100 MW put up for bidding), Tohoku (155 MW), Tokyo (1,000 MW), Chubu (200 MW), Kansai (1,000 MW), and Kyushu (200 MW).

In 1996, a total of 2,655 MW power sources to be commissioned in the fiscal years from 1999 to 2002 were invited for the bidding. Independent power producers who participated in the bidding numbered 100 in total, with their combined capacity amounting to 10,813 MW, 4.1 times larger than the size tendered. Successful bidders numbered 20, who were expected to supply a total of 3,046.9 MW.

Successful bidders come from diverse industries, and include steelmakers, oil refiners, gas producers, heavy electrical machinery makers, and trading firms. The principal fuels employed in their power generation are equally diverse, ranging from residual fuel oil to kerosene, heavy fuel oil, LNG and town gas. Above all, steelmakers are conspicuously on the offensive. For example, the Nippon Steel Corporation (NSC) won the bidding of four electric utilities, including Hokkaido (100 MW), Tohoku (136 MW), Kansai (133 MW), and Kyushu (137 MW).

Among others, Kobe Steel Ltd. was the winner of the bidding of Kansai Electric Power (54.5 MW, 659 MW), Nakayama Godo Hatsuden (a joint venture of Nakayama Steel Works and Tomen) of Chubu Electric Power (135.5 MW), and Meikai Hatsuden, a subsidiary of NSC-affiliated Topy Industries of Chubu Electric Power (135 MW). With affiliates and subsidiaries included, the steel industry overall won 1,626 MW, or 50 per cent of the whole MW put up for bidding. The principal generating fuel in use in the steel industry is coal.

The rate of in-plant power generation is high among steelmakers. Besides, having ports, berths and vast mothballed lands, they are already well-equipped with the necessary infrastructure for power generation. Also, steelmakers are advantaged in that they know well how to secure and handle overseas coal, which is more competitive than alternative fuels in generating cost terms, and have acquired the know-how of power plant operation. On top of this, they can supply steel products to build power plants themselves, which further increases their advantages. Further, their rich experience in power plant operation enables them to make in-depth cost analyses on any forms of power generation of competitive bidders, so that they can offer successful bidding prices.

(b) More or less successful first bidding results

The first bidding yielded more or less successful results. Participants in the bidding were four times larger than called for. In price terms, the bidding reportedly allowed electric utilities to secure power sources for much cheaper prices than they expected. Taking Tokyo Electric Power as an example, the avoided cost of its baseload power source is ¥9.30/kWh, of which the utilization factor is 80 per cent. While the yardstick of the successful bidding price was reportedly put at around ¥8/kWh, it is widely known that Tokyo Electric Power could procure power sources for the mid-¥7/kWh level, even cheaper by around ¥2 than the avoided cost. While some worried

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whether or not competitive bidding for wholesale electricity supply could be established as a market, and that bidding prices should stick to the ceiling prices set by electric utilities, the outcome of the actual bidding completely wiped away such worries. The outcome was fully foreseeable from the experience of the United States of America, to begin with.

Even if competitive bidding itself was successful, the question is to what extent it can contribute to reducing (electricity) rates, which is an ultimate objective of freeing the Japanese power production market. Competitive bidding can be defined as competitive procurement of new power sources. But, because the competition is limited among newly built power sources, few immediate effects can be expected in lowering (electricity) rates. And yet, if competitive bidding are stimulated more, and if IPPs can build much cheaper power sources than at present, competitive bidding can surely contribute to rate reduction in the long run. Further, it is noteworthy that, as already demonstrated in the United States, intensifying competition among IPPs urges makers to cut their power plant prices. This can also affect electric utilities' costs of procuring materials and equipment, and eventually lead to a lower avoided cost. Thus, on the assumption that the greater part of domestic-overseas electricity rate differentials could be explained by capital cost, the effect to be expected from the bidding system is not small.

2. Future issues

(a) Bidding frame to be expanded

Discussed here are the major issues of wholesale electricity supply. In fiscal year 1997 again, bidding is definitely scheduled by several electric utilities, including Tohoku (150 MW), Tokyo (1,000 MW), Chubu (400 MW), Kansai (700 MW), Chugoku (200 MW) and Kyushu. Increasing the frequency of bidding allows continuous reductions in generating costs. However, too-frequent bidding needs special attention, because it can urge some electric utilities to narrow the frame of a bid year by year to the extent that IPPs can hardly demonstrate economy of scale. For this reason, it is more desirable to expand the frame of a bid as much as possible. While competitive bidding is offered in a discretionary way by electric utilities, some argue that regulatory authorities had better intervene in the organization and evaluation of bidding. In this regard, some case studies in the United States show that to reform bidding procedures critically requires good communication among the three parties concerned; the regulatory authorities, the electric utilities and the bidders. Transparency of bidding procedures can then be cited as the key to a successful bidding system for wholesale electricity supply.

(b) Treatment of the non-price element in evaluating competitive bidding results

In general, if the price element of the bidding results fails to decide a winner, a successful bidder ultimately depends on non-price elements. The weight of the two varies depending on the country. For instance, very heavy weight is put on non-price elements in the United States. In sharp contrast, the evaluation of bidding results in Japan centres on the price element, without raising any problems, because bidders are judged fully qualified for the experience of power plant operation, and certainties of funds, construction and fuel procurement, among others. And yet, the environmental characteristics of a given power plant deserve positive evaluation. Amid growing concerns over environmental problems worldwide, IPPs taking sophisticated environmental measures should be scored highly, and it is recommended that the overall evaluation of bidding results should reflect external effects on the environment.

(c) Wholesale supply of electricity by IPPs in terms of dual supply as well as to its own use

In contrast with a new power plant for outside use only, although it might involve such technical problems as deviation from the specified supply pattern, the wholesale supply of IPP electricity by dual supply as well as for its own use is deemed to have much advantage for IPPs in terms of cost. This might raise some issues to be discussed in further detail.

XV. EFFORTS BY THE REPUBLIC OF KOREA TO HARMONIZE ENERGY, ECONOMY AND ENVIRONMENT*

A. ENERGY IN THE REPUBLIC OF KOREA AT A GLANCE

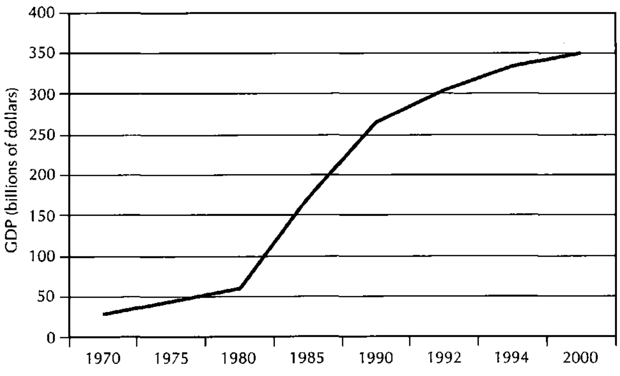
1. Economic situation in brief

The Republic of Korea has sustained rapid economic growth for over 30 years. From 1962 through 1995, the nation's GNP expanded from 2.3 billion US dollars to 451.7 billion US dollars, turning the Republic of Korea into the world's eleventh largest economy and boosting the per capita GNP from $87 to $10,076, an annual increase of 7 per cent in nominal terms.

The growth of the economy powered by an export boom beginning in the early 1960s has transformed the nation from an agrarian to an industrialized and urbanized middle-income society. In 1995, the share of agriculture in GDP was only 7 per cent, while that of mining and manufacturing was around 30 per cent.

Starting out with a reliance on light industries such as textiles in the early stages of industrialization, the emphasis soon shifted to such heavy industries as chemicals, iron and steel, machinery and automobiles. Since the 1980s, the main industrial players have included electronics, especially semi-conductors.

Figure XV.1 GDP growth of the Republic of Korea



Note: The figure for 2000 is an estimate by the Korea Energy Economics Institute under a business-as-usual scenario which is based upon the assumption that current trends are maintained.

The growth of GNP hovered above the 10 per cent mark throughout the 1980s, but began to slow down in the 1990s, to 8.6 per cent in 1994 and 9.0 per cent in 1995. Now, the country appears to be headed on a path of more moderate growth.

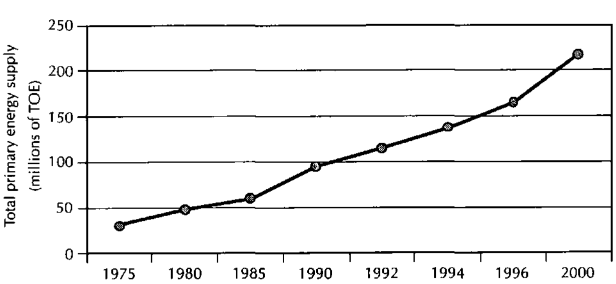
2. Energy supply and demand

In line with the nation's dramatic economic growth, energy demand has increased sharply as well. Total energy demand, which stood at 9.5 million TOE in 1961, increased 16-fold to 150.4 million TOE in 1995, to rank the Republic of Korea as the eleventh largest energy-consuming nation in the world. Between 1985 and 1995, the country's annual average growth rate in energy demand was third, at 10.3 per cent, trailing Thailand's 12.1 per cent and Malaysia's 11 per cent. This trend of a high increase in energy demand is continuing, as energy consumption rose 9.62 per cent in 1995 over the previous year, considerably higher than the 2.51 per cent in Japan, 1.67 per cent in the United States and 2.57 per cent in France.

The high rate of increase in energy demand is expected to persist in the future because of expected sustained economic growth, despite nationwide efforts driven by the Government to encourage energy conservation and higher energy efficiency. According to an estimate by the Korea Energy Economics Institute under the business-as-usual scenario, total primary energy demand will increase at a rate of 8.2 per cent up to 2000.

Per capita energy consumption has also been increasing commensurate with economic growth and

Figure XV.2 Increase in total primary energy supply



* Ministry of Trade, Industry and Energy Republic of Korea, May 1997.

Figure XV.3 Increase in total primary energy supply: comparison among selected countries

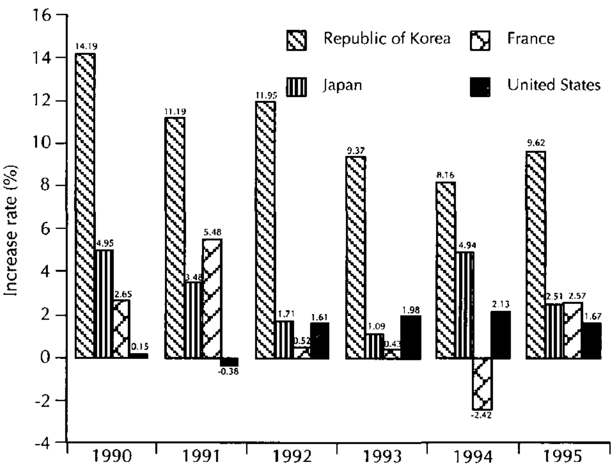
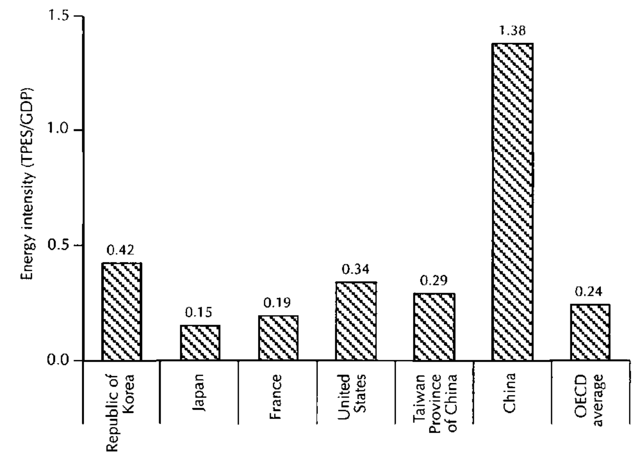


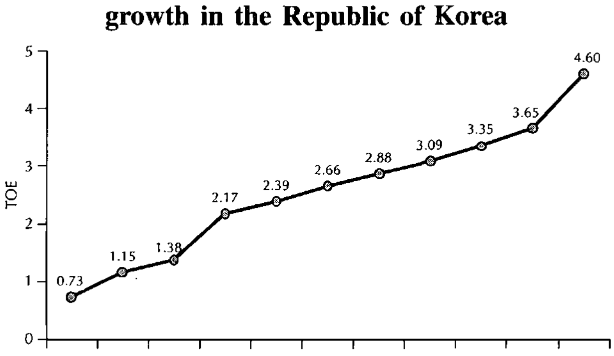
Figure XV.5 Comparison of energy intensity in major countries or areas in 1995
(Millions of TOE/GDP (thousands of dollars))



improvements in the national standard of living. The per capita energy consumption in 1995 was 3.35 TOE, considerably lower than the 7.68 TOE per capita in the United States but quickly approaching France's 4.06 TOE and Japan's 3.90 TOE.

The average per capita income of OECD countries is 2.5~3 times higher than that of the Republic of Korea while their per capita energy consumption is twice as high, which implies the potential that the Republic of Korea's per capita energy consumption will continue to increase along with economic expansion in the future.

Figure XV.4 Per capita energy consumption growth in the Republic of Korea



The energy intensity in the Republic of Korea, the ratio of total energy consumption to GDP, is somewhat higher than that of most OECD countries, but this is mainly because of its industrial structure, which is focused on such energy-intensive industries as iron and steel, cement and chemicals.

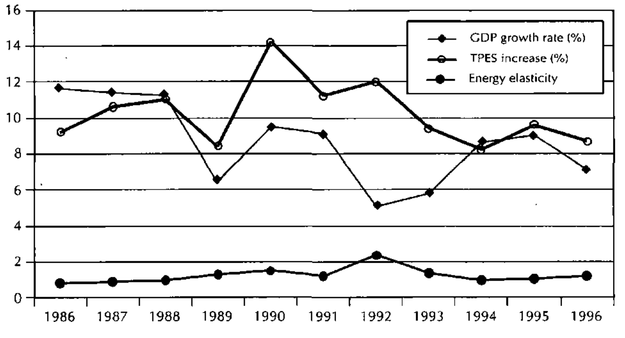
In terms of specific energy consumption (energy input to produce unit product), however, there is little difference in energy efficiency between the major energy-intensive industries in the Republic of Korea and most OECD countries, as seen in an example of the Republic of Korea-Japan comparison in terms of energy-intensive products in table XV.1. Another striking feature of the Republic of Korea's energy consumption is the unusually high share of non-fuels, most notably naphtha for petrochemical feedstock, which reaches 15 per cent, much higher than the 3~4 per cent in most OECD countries. As far as only pure energy consumption is concerned, therefore, while excluding these non-fuels, the Republic of Korea's energy intensity falls significantly to levels that are almost comparable with those of some OECD countries.

Energy elasticity reached a high of 2.36 in 1992 after energy consumption surpassed GDP growth since 1989 but has stabilized recently around the 1.00 mark.

Table XV.1 Comparison of the major energy-intensive products of the Republic of Korea and Japan

	Republic of Korea		*Japan*	
Industry (item)	*Company*	*Energy intensity (Mcal/t)*	*Company*	*Energy intensity (Mcal/t)*
Iron and steel (steelmaking)	PO	5 288	SN	6 189
Petrochemical (ethylene)	DL	5 232	TO	5 300
Ceramic (cement)	SY	265	ON	260

Figure XV.6 Changes in energy elasticity



In the Republic of Korea, reducing the energy elasticity down to unity amidst rigorous economic growth is one of the Government's key energy policy objectives.

Looking at energy consumption for 1995, the industrial sector accounted for about one half of the total, while the commercial and residential sector and transport sector accounted for slightly more than 20 per cent each. By fuel, the reliance on petroleum as an energy source was over 60 per cent and that on coal was 18.3 per cent, indicating that the proportion of fossil fuels is still high.

Looking at the annual growth in final energy consumption between 1986 and 1995, the industrial sector averaged 18.8 per cent, the commercial/ residential sector 5.7 per cent, the transport sector 25.2 per cent and the public sector 0.2 per cent, revealing that the rates of increase were the highest for the industrial and transport sectors.

Figure XV.7 Final energy consumption by sector, 1995

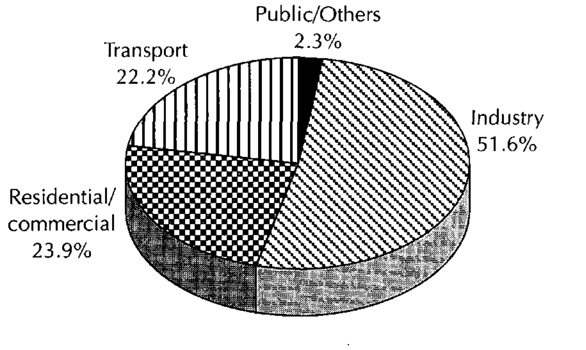
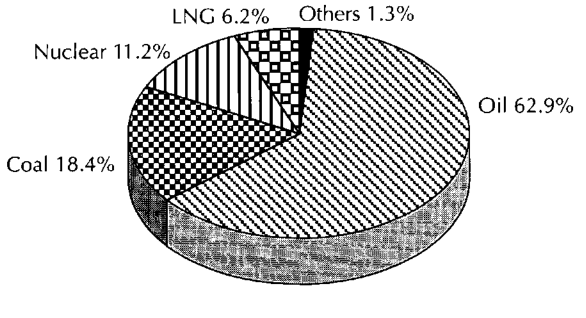
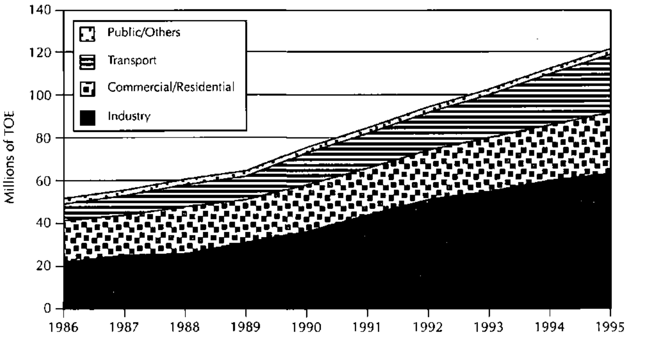


Figure XV.8 Final energy consumption by source, 1995



The strong increase in final energy consumption in the industrial sector was mainly due to the growth of energy-intensive industries in the 1980s. The transport sector consumed 27 million TOE in 1995, 22.2 per cent of the total energy consumption. This is still lower than the OECD average, however, and it has the potential for further increase.

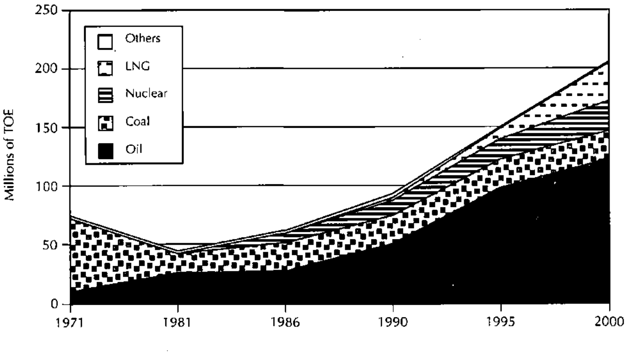
Figure XV.9 Sectoral share change in total final energy consumption



Owing to the rapid economic growth since 1986 and the subsequent improvement in the standard of living, the consumption of domestic anthracite coal has been decreasing. Conversely, the reliance on petroleum has been increasing rapidly. At the same time, the demand for gas, electricity and other forms of clean fuel has been picking up.

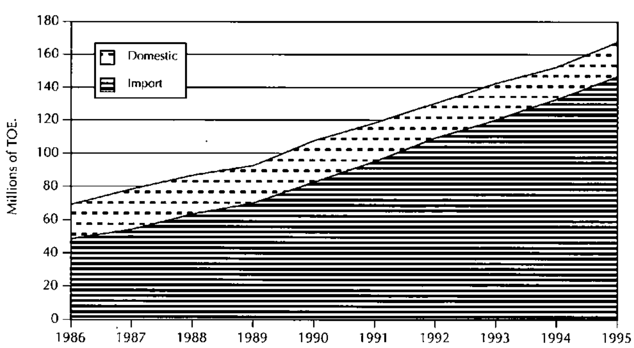
As the Republic of Korea has no significant indigenous energy resources, almost all of its energy needs have to be met by imports. In 1995, the energy import dependence ratio, including nuclear energy, was

Figure XV.10 Changes in total primary energy supply shares by source



a high 96.79 per cent, with 145 million TOE of the total of 150 million being imported from foreign sources. The Republic of Korea paid $18.6 billion for energy imports in 1995, equivalent to 14 per cent of its total inbound shipments. In particular, the import of petroleum reached 2.3 million barrels per day, ranking the Republic of Korea the world's fourth largest importer after the United States, Japan and Germany. Converted into TOE, petroleum imports reached 94 million TOE, accounting for 65 per cent of 1995 total energy imports.

Figure XV.11 Energy import dependence



B. EMERGING ISSUES

1. Global warming and the United Nations Framework Convention on Climate Change

Since the adoption of the United Nations Framework Convention on Climate Change at the Earth Summit at Rio de Janeiro in 1992, which marked the emergence of environmental problems as major global issues, there have been continuing international discussions on the emission of gases responsible for the greenhouse effect, limiting the use of fossil fuels, the imposition of energy and carbon dioxide gas taxes and strengthening of energy efficiency regulations.

The Republic of Korea is currently recognized as a developing country under the Framework Convention and it will be difficult for it to limit the emission of carbon dioxide to the levels of other OECD countries in the foreseeable future. However, as one of the 11 biggest energy-consuming countries in the world, the Republic of Korea has been striving to balance its energy efficiency improvement, environment conservation and economic growth, emerging as a model case of environmentally sound and sustainable economic growth.

2. Limitations to the expansion of energy supply facilities

To meet the rising demand for energy accompanying economic growth and increases in personal income, there is an ever-growing need for the construction of new power plants, expansion and sophistication of oil-refining facilities, and building of LNG storage depots and distribution pipelines, all of which require huge investments. (It is estimated that approximately 51 billion US dollars will be needed for the construction of new power plants alone by 2010.)

However, owing to a policy of keeping energy costs low and the reality of the domestic capital market, it is difficult to raise sufficient funds to finance these projects. In addition, the "not-in-my-backyard" syndrome is making it difficult to secure suitable sites on which to construct power generation and energy storage facilities.

3. Changes in lifestyle

Economic growth and the resulting ability of the population to afford greater convenience and comfort is pushing consumers to want bigger and better products. In terms of home electronics appliances, the best-selling model television sets, refrigerators and washing machines increased 30 per cent in size between 1990 and 1995. In addition, the number of compact cars and other light vehicles on the road in the Republic of Korea is considerably smaller, with consumers now preferring to drive larger sedans. Owing to these changes in lifestyle, energy demand in the commercial and residential sector has been exploding. Consequently, it is becoming more and more obvious that there is a need to encourage a nationwide campaign to move toward energy-conserving lifestyles.

4. Energy security

Over 95 per cent of the energy sources in the Republic of Korea are imported. In particular, the dependence on petroleum increased from 48.2 per cent in 1985 to 62.6 per cent in 1995, mainly owing to the explosive increase in demand in the transport and industrial sectors caused by the soaring number of vehicles and changes in industrial structure.

When considering that petroleum dependency rates are about 30-50 per cent in other OECD countries and that 77.8 per cent (1996 figure) of the petroleum needs in the Republic of Korea are met by imports from the Middle East, there is a serious problem of energy security. Accordingly, there is high policy priority on the need to improve energy efficiency and conservation, which is also vital from the perspective of reducing the nation's snowballing trade and current account deficits.

5. Urbanization and air pollution

With the rapid urbanization taking place since the 1960 and the increasing number of vehicles on the roads, the air pollution problem in major cities in the Republic of Korea is becoming more and more serious. The use of natural gas and district heating in lieu of anthracite coal for cooking and heating, has fortunately made a viable contribution to improving air quality. However, the smog effect caused by the emission of pollutants by vehicles is a serious problem which warrants the development of effective solutions.

Therefore, energy conservation and efficiency improvement are one of the foremost priorities of the country's energy-related policy, along with the switch to cleaner fuels and the development of new and renewable energy sources in the energy plan.

C. ENERGY EFFICIENCY AND CONSERVATION POLICY AND PROGRAMMES

Introduction

Efforts by the Republic of Korea to promote energy efficiency and conservation were triggered by the two oil crises in the 1970s. Faced with an era of high oil prices all over the world, the Republic of Korea, which has to import virtually all of its energy, faced the challenge of unstable energy supply and demand. To overcome this situation, the Government developed energy efficiency and conservation policies while endeavouring to secure energy supply.

In 1978, the Ministry of Energy and Resources was established to administer the energy and resource policies, and in 1980 the Korea Energy Management Corporation (KEMCO) was founded to implement energy efficiency and conservation policy and programmes. In addition, the Government promulgated the Rationalization of Energy Utilization Act in 1980 to serve as the basic law for energy efficiency and conservation. In the same year, the Energy Saving Facility Fund was set up to support investments for energy conservation facilities, while a portion of the Petroleum Business Fund (PBF) was reserved for energy conservation programmes and to finance R and D programmes for new and renewable energy sources.

The Petroleum Business Fund was built with taxes imposed on imported petroleum and was mainly used to build up the strategic petroleum reserves and to support the expansion of the natural gas supply, the installation of energy-saving facilities and the development of alternative energy technologies. During the oil glut of the late 1980s when oil prices fell dramatically, the Petroleum Business Fund was utilized to ensure that oil prices did not fall too low in the domestic market. In the process, a fund of some 7 billion US dollars was established. The management of the Fund was widely recognized as one of the most successful energy policies in late 1980s and early 1990s. This Fund, which was the precursor of today's energy tax, was absorbed into the Special Account for Energy and Resources Projects in 1995.

Energy efficiency and conservation policies in the early 1980s involved rather simple measures, including public awareness programmes, energy audits and financial support for energy efficiency investments. In the latter part of the 1980s, with the stabilization of

Table XV.2 Energy efficiency expenditure
(10^8 won nominal)

Fund source	*1981-1988*	*1989*	*1990*	*1991*	*1992*	*1993*	*1994*	*1995*	*1996*	*Total*
Petroleum Business Fund	9 258	2 132	1 310	1 133	1 064	1 325	1 814	1 866	2 083	21 985
Energy Rationalization	165	5	27	35	44	34	49			359
Financial	5 581	–	–	–	–	–	–	–	–	5 581
Government	100	–	–	–	–	–	–	–	–	100
Total	**15 104**	**2 137**	**1 337**	**1 168**	**1 108**	**1 359**	**1 863**	**1 866**	**2 083**	**28 025**

Note: As of April 1997, 1 US dollar = about 900 won.

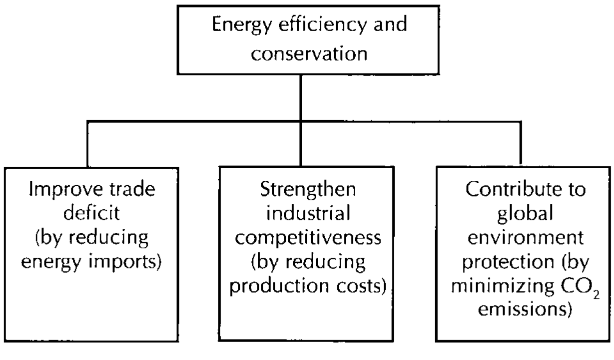
the oil market and the beginning of the era of low oil prices which brought about sharp increases in oil demand, the Government sought more effective policy measures to supplement existing ones.

From the beginning of the 1990s, oil prices rebounded with the outbreak of the Gulf War, and the issues of environmental protection rose to the surface, particularly encouraged by the United Nations Conference on Environment and Development, which brought to the fore the need to reduce the use of fossil fuels and to improve energy efficiency. As a natural course of economic development, since the late 1970s there has been an expansion in energy-intensive industries in the Republic of Korea. The rapid expansion of energy-intensive industries, along with higher standards of living, resulted in huge increases in the energy demand, mainly in the industrial and transport sectors. Consequently, the Government implemented more mid- and long-term energy efficiency and conservation policy measures, including the five-year efficiency improvement plan for energy-intensive companies, energy impact assessment programmes, energy labelling and a comprehensive demand-side management plan for public utilities.

1. Objectives and basic directions for energy efficiency and conservation policies

(a) Policy objectives

- ❑ To improve the trade deficit through reduction of energy imports
- ❑ To strengthen industrial competitiveness through reduction of production costs
- ❑ To contribute to global environment protection through reduction of CO_2 emissions



(b) Basic directions

- ❑ To enhance efficiency in the whole energy flow of production, distribution and consumption
- ❑ To strengthen demand-side management
- ❑ To make the best use of the market mechanism to encourage and expand investments in energy-saving facilities
- ❑ To strengthen regulations to an appropriate level in key areas, including energy equipment and appliances efficiency standards
- ❑ To promote an energy and resource-saving lifestyle through strengthening energy conservation awareness, adjusting energy price levels properly, and developing and improving other related programmes
- ❑ To strengthen international cooperation

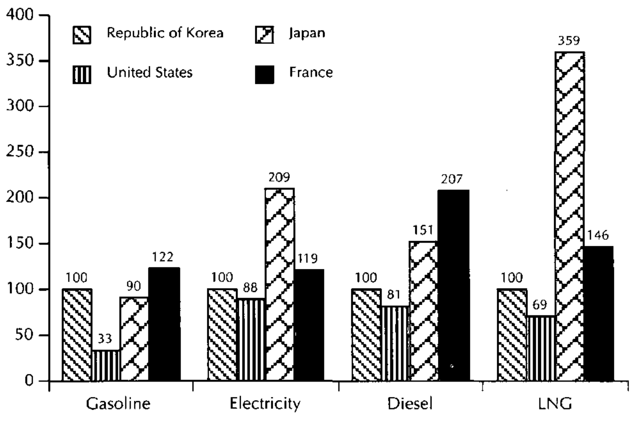
2. Energy efficiency and conservation policy and programmes

Cross-sectional policies and programmes

Energy Pricing

The Government of the Republic of Korea has played an active role in the price-setting process for most forms of energy. To encourage and sustain economic development and growth, domestic energy prices have been maintained somewhat low to provide reasonable cost of energy supplies. For instance, while the per capita GNP expanded fourfold from 1985 through 1995, energy prices actually fell. But, as the 1993 New Economic Five-year Plan calls for the reform of the economy by emphasizing deregulation, strengthening the market mechanism, promoting private-sector participation and institutional restructuring, the Government has made gradual progress towards price deregulation in line with the new emphasis on reform, as seen in the price of gasoline in figure XV.12, which is about the same as or higher than in most industrialized countries. However, it is true that the prices of most oil products and electricity are comparatively low, thus giving little motivation for saving energy. Consequently, the Government is planning to gradually adjust energy prices to more appropriate levels high enough to encourage people to save energy.

Figure XV.12 Comparison of the energy price indices of major countries



Note: (1) All figures are relative to the base of the Republic of Korea set as 100.

(2) Gasoline prices are based on those in the Republic of Korea in January 1997; all others are based on October 1996 data.

Financial and tax incentives for energy efficiency investments

Following the 1979 oil price increase, the Government established the Energy Saving Facility Fund to fund facility investment that would generate energy-saving investment in industry. A fund of about 200 billion won (250 million US dollars) was established in 1980 and was supplemented with 23.8 billion won (30 million US dollars) for the energy savings projects by the Petroleum Business Fund (then the Petroleum Stabilization Fund).

At present, almost all funds for energy efficiency originate from the Petroleum Business Fund. The loan money, called the Rational Energy Utilization Fund, is made available through loaning institutions. This Fund is operated by KEMCO on behalf of the Government. Almost all energy efficiency expenditures are for loans, excluding the KEMCO annual budget at about 25 million US dollars as of 1995. The terms of the loans depend on the type of project. In 1996, loans were provided at the interest rate of 5 per cent a year, with a three-year grace period and five-year payback period for industry projects; 7 per cent, five-year grace and five-year payback period for combined heat and power industrial projects; and 5 per cent, three-year grace and five-year payback period for R and D projects. About 50 per cent of the Rational Energy Utilization Fund has been made available to energy efficiency activities so far, while 45 per cent has gone to finance district heating and CHP plants.

The Government also offers tax incentives for energy efficiency investments based on article 26 of the Regulations on Tax Reduction and Exemption. Before 1997, the replacement of inefficient industrial furnances and kilns and the installation of co-generation facilities, alternative fuel-using facilities and other equipment and facilities that could bring forth more than 10 per cent in energy savings were all qualified for a 10 per cent income tax deduction for domestic products and for 3 per cent for foreign ones. But from 1997, a 5 per cent income tax deduction is provided equally, regardless of its origin.

Public Awareness Programmes

In an effort to improve public awareness of the need for energy conservation, the Government has implemented a number of nationwide campaigns. Through public campaigns, community meetings, schools and public organizations, non-governmental organizations and civic groups, the Government has been urging active participation in the conservation of energy. The Government has also designated schools as model institutions for energy conservation programmes and included energy savings in the curricula of elementary and middle schools, to educate the younger generation about the importance of conserving energy and protecting the environment.

At the same time, the Government, to inspire public support through the staging of various awareness events, has designated November as Energy Conservation Month and the first Friday of every month as Energy Conservation Day. In addition, every other year, an Energy Conservation Rally is held to generate the momentum of energy conservation throughout the country by recognizing those making viable contributions to energy conservation. Since 1975, the Government has also organized an annual Energy Conservation Exhibition (ENCONEX) with the purpose of disseminating state-of-the-art energy-efficient systems.

Among the public awareness programmes that warrant particular attention is the Green Energy Family, which began in 1995. Its first undertaking was the Green Light Project, which aims to save 4,977 GWh by 2001 through the widespread distribution of high-efficiency lighting appliances to both households and industries. All enterprises and families are invited to participate in the project, for which KEMCO provides consulting services, as well as the right to use a pertinent logo. The campaign is a continuing, step-by-step programme. "Green Light Advertising,"

Table XV.3 Registered energy service companies in the Republic of Korea and their major activities

No.	*Name of company*	*Registration date*	*Field of activities approved*	*Major activities engaged in*
1	Choong-Ang Development Co. Ltd.	24 June 1993	Industry and Building	– Energy-efficient lighting substitution Project for Choong-Ang Ilbo (1994) – Energy-efficient lighting substitution Project for Samsung Electronics
2	Tae-Il Precision Co. Ltd.	22 November 1994	Building	– Energy-efficient lighting substitution Project for universities, public and government buildings, and other private buildings (1994-1995)
3	LG Industrial Electronics Co. Ltd.	25 June 1996	Industry and Building	
4	E.C.I Co. Ltd.	9 July 1996	Building	
5	Sam-Young Facilities Co. Ltd.	24 December 1993	Building	
6	Byuk-San Development Co. Ltd.	24 October 1993	Industry and Building	
7	Samsung Engineering Co. Ltd.	6 October 1994	Industry and Building	– Diesel-engine Co-generation (3,000 kW) Project for Moojoo Resort (1994-1996)
8	Samsung Heavy Industries Co. Ltd.	14 December 1993	Industry and Building	– Diesel-engine Co-generation (2,000 kW) Project for Everland (1995)
9	Hyundai Heavy Industries Co. Ltd.	15 January 1997	Industry and Building	
10	LG Honeywell Co. Ltd.		Building	
11	Litech Electronics Co. Ltd.	June 1996	Building	– Energy-efficient lighting substitution (1996)
12	Hankook Heavy Industries Co. Ltd.	April 1997	Industry and Building	

"Green Traffic" and "Green Energy 10" programmes will follow in the near future.

Facilitating the activities of energy service companies

Enhancing the role of energy service companies (ESCOs) in the energy conservation market was identified as a key measure in the Rationalization of Energy Utilization Act. As of April 1997, 12 ESCOs are registered. But the scope of energy service company activities has been limited so far to such areas as the replacement of low-efficiency lighting equipment and the construction of co-generation facilities for industrial plants and commercial buildings. In order to boost ESCO activities and to encourage third-party financing, the Government has provided soft loans and tax incentives for investments in energy efficiency projects. Seed money for establishing an ESCO is also available from the Government.

To further promote ESCO activities, the Government offers even more preferential conditions in loans and tax deductions from 1997, and the tax incentives will be given to both the ESCOs and end-users. In 1996, the Energy Saving Mart was inaugurated to provide a matchmaking venue for ESCOs and major energy consumers, their most prospective potential customers, where ESCOs were given an opportunity to explain the concept of their unique business showcasing some successful projects, exibit energy efficiency and conservation technologies, and give consulting service about the energy-saving investments. Encouraged by the success of this programme, the Government is now planning to hold the event on an annual basis.

Another major project undertaken in 1996 was Energy Savings Performance Contracting (ESPC), similar to the Federal Energy Management Programme of the Department of Energy of the United States. In this project, energy efficiency investments are made by ESCOs, and the resulting savings are divided among public organizations under respective contracts. This means that public organizations can obtain the expertise and technology of ESCOs without a heavy initial investment and incurring high risk.

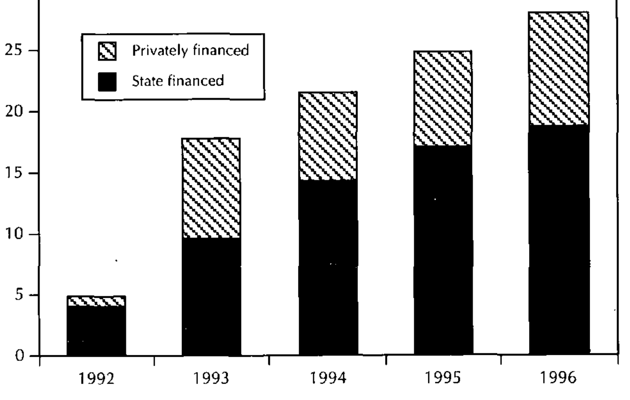
Promoting energy efficiency technology R and D activities

The priority of energy technology R and D is placed on energy conservation and the development of alternative energy to fossil fuels. The Government leads the R and D activities in collaboration with industry, universities and research institutes. The priority projects are financed under the government budget and energy-related funds from the Government and industry.

In 1991, the Government set up a Five-Year Basic Plan for the Development of Energy Efficiency and Conservation Technologies (1992-1996) to promote R and D energy efficiency and conservation technologies in a more systematic and effective manner. The R and D Management Centre for Energy and Resources (RaCER) was founded as an affiliate of KEMCO in 1992 to take charge of managing the whole R and D process and financial assistance.

Between 1992 and 1996, a total of 7,000 personnel from 880 organizations, ranging from private and public companies to research institutes, participated in joint or individual projects, and the Government provided financial support amounting to about 70 million US dollars for 289 R and D programmes.

Figure XV.13 Financial assistance for the development of energy efficiency and conservation technologies, 1992-1996



Note: As of May 1997, 1 US dollar = approximately 900 won.

At present, a Ten-Year Energy Technology Development Plan, from 1997 to 2006, is being implemented. This plan focuses on the following three categories:

- ❑ Energy efficiency and conservation technologies: 12 technologies, including high-efficiency industrial furnaces and lighting appliances
- ❑ Alternative energy technologies: four technologies, including solar and fuel-cell
- ❑ Clean energy technology: five technologies, including fluidized bed coal combustion

Daylight savings time system

A daylight savings time system is currently in use in 70 countries around the world on account of its positive effects, such as reduction in the use of energy, increase in personal leisure time and spreading traffic concentration during rush hours. The Government of the Republic of Korea has conducted public hearings and other opinion-gathering programmes in an effort to compile data to support the adoption of the system. Based upon the Presidential Decree of Law concerning Standard Time, the Government is now considering putting this system into effect between 1 May and 30 September each year by pushing back the clock by one hour.

Demand-side management

As there exist escalating difficulties in securing suitable sites and huge investment capital for constructing energy supply facilities, great emphasis has been placed on the importance of demand-side management (DSM).

Since the beginning of the 1990s, the dramatic increase in the use of air conditioners in the hot summer months has caused a severe drain on electricity reserves and has resulted in a virtual shortage on several occasions. Accordingly, the Rational Energy Utilization Act was revised in July 1995 to adopt DSM to make related investments by utilities mandatory from 1996. The result has been that Korea Electric Power Corporation (KEPCO), the only power utility, invested some 45 million US dollars in such DSM programmes as Load Management, Time-of-Use Rate System, Discount System for Voluntary Curtailment, Promotion of an Ice-storage Cooling System, Discounts for Midnight Use and Rebates for Efficient Lighting Appliances. In addition, the Korea Gas Corporation

Table XV.4 1997 investment plan by main utilities

(Millions of US dollars-approximate)

Investment Areas		*KEPCO*	*KGC*	*KDHC*	*Total*
Efficiency improvement	Projects	– Dissemination of energy-efficient lighting appliances – R and D	– Development of energy efficiency and conservation technologies – Development of facilities operation modes	– Instruction on efficient heat use	
	Investment (subtotal)	31.4	1.3	0.25	33
Load management	Projects	– Improvement of rate system (replacement of electronic meters) – Discount for voluntary curtailment and summer vacation adjustment – Promotion of the diffusion of ice-storage cooling system – R and D of demand controller	– DSM research – Development of gas cooling and co-generation equipment – Research of DSM rate system	– Education for end-users	
	Investment (subtotal)	25	2.8	0.04	28
Load shift/fuel shift/other	Projects	– Increase of midnight power demand	– Research on LNG vehicles	– Fuel switching in apartment houses	
	Investment (subtotal)	3.5	0.7	0.03	4.2
Total investment		**60.1**	**4.8**	**0.3**	**65.2**

Table XV.5. Phase-by-phase technology development plan for new and renewable energy sources

	Phase I	*Phase II*	*Phase III*	*Phase IV*
Plan period	1988-1991	1992-1996	1997-2001	2001-2006
R and D goal	Establish foundation for research	Establish foundation for practical application	Development of targeted core technologies	Commercialization of developed technologies
Target NRSE supply ratio of TPES	Financial support	Demand development, demonstration	Market development	Expansion of dissemination
	(0.5%)	(0.6%)	(1.3%)	(2.0%)

(KGC) and the Korea District Heating Corporation (KDHC) spent about 4.8 million US dollars and about 300,000 US dollars, respectively, on DSM projects.

3. Development and dissemination of new and renewable sources of energy

The Republic of Korea first began investing in the development of new and renewable sources of energy in the 1970s. These efforts gained momentum through the promulgation of the Alternative Energy Development Promotion Act of December 1987. However, it was not until the following year, with the formulation of the Basic Plan for the Development of New and Renewable Energy Technologies, that systematic and effective technology development began to take concrete shape.

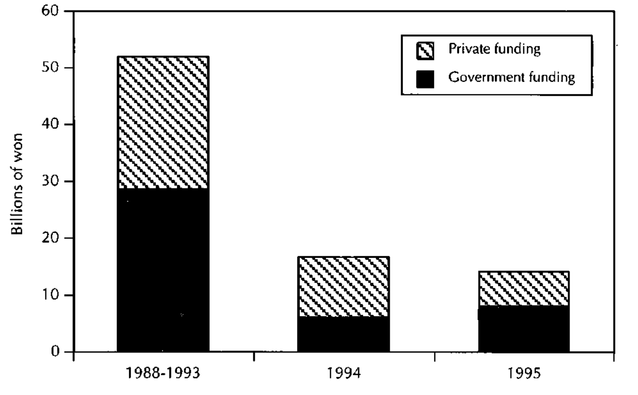
The Basic Plan consists of four phases, as shown in table XV.5. If the fourth phase has been completed by the year 2006, new and renewable sources of energy (NRSE) would account for 2 per cent of total energy demand.

Eight energy sources (solar, bio, waste, small hydro, wind, hydrogen, ocean and geothermal) and two related technologies (fuel-cell and coal utilization technologies) defined by the Alternative Energy Development Promotion Act are classified into the following three categories:

- ❑ Core technologies: photovoltaic, solar thermal, fuel-cell and integrated gasification combined cycle (IGCC)
- ❑ General technologies: waste, bio, wind power and coal utilization technology
- ❑ Basic technologies: small hydro, ocean, hydrogen and geothermal

The R and D Management Centre for Energy and Resources (RaCER), an affiliate of KEMCO, was established in 1989 to oversee research and development for new and renewable energy sources. Its responsibilities extend to the selection, support, operation, evaluation and management of projects. When the budget and action plans for each year are finalized, the Centre receives applications for research projects for the following year, selects the appropriate research projects and provides full funding for universities and research centres and a portion of the funding for private companies and research cooperatives.

Figure XV.14 Financial support for R and D of NRSE technologies



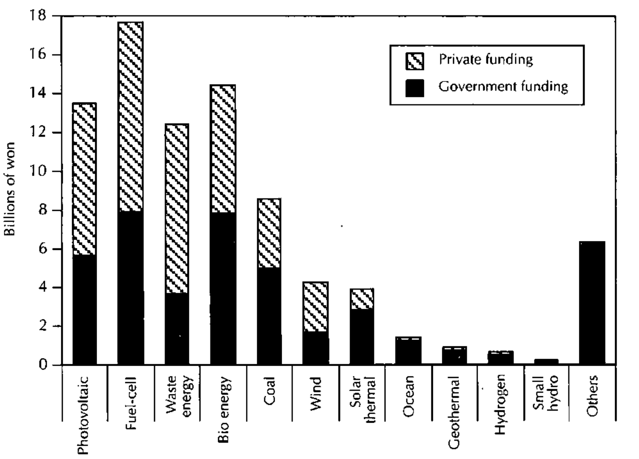
Note: As of May 1997, 1 US dollar = approximately 900 won.

In general, universities focus on basic technologies, research institutes on practical technologies, and private companies on technologies readily commercializable.

Between 1988 and 1995, the use and supply of new and renewable energy has been expanding at a rapid rate, 27 per cent per year, owing mostly to the Basic Plan. However, the percentage of supply as a ratio of total energy demand remained at a low 0.61 per cent in 1995, mainly because of the stabilization of energy prices from the mid-1980s.

In the future, the Government will focus on extending more funds for related research, implement demonstration supply projects, and acquire the latest technologies through strengthened international cooperation in order to increase the use of new and renewable energy sources.

Figure XV.15 Financial support for individual technologies, 1988-1995



Note: As of May 1997, 1 US dollar = approximately 900 won.

Table XV.6 Supply of new and renewable energy by year

	1989	*1991*	*1993*	*1995*
Amount supplied (thousand TOE)	214	413	649	908
Total primary energy supply (thousand TOE)	81 619	103 622	126 368	149 572
Supply ratio (%)	0.26	0.40	0.51	0.61

D. FUTURE CHALLENGES

1. Towards a less energy-intensive industrial structure

Through the 1970s and 1980s, the Government of the Republic of Korea oriented its policies towards the promotion of such energy-intensive industries as iron and steel, cement and petrochemical. These industries, as industrial materials producers, supported other key industries such as machinery, electronics and fine chemicals, and thus made a significant contribution to the development of the Korean economy. For the Republic of Korea, which relies on import for almost all of its energy needs, however, it is very urgent to improve the energy intensity of the industrial sector as a whole. Consequently, the Government will seek to improve the energy efficiency of these energy-intensive industries, while at the same time fostering low-energy-consuming industries such as electronics, computer software, information and communication technology, and biotechnology.

2. Rationalization of energy prices

The Government recognizes that low energy prices constitute one of the critical factors behind excessive energy consumption. In an attempt to curb the wasteful use of energy and encourage consumers to buy high-efficiency equipment and appliances, the Government is planning to rationalize its energy price structure. Considering the adverse effects that a sudden increase in energy prices may bring about, the Government will prudently continue its efforts to bring prices more into line with the average level of non-oil-producing OECD countries.

Along these lines, the low electricity rates currently being applied to the industrial and agricultural sectors will be gradually raised. In addition, a price pre-notification system will be introduced to send accurate price signals to industry and consumers, and eventually push energy prices up to the levels in non-oil-producing OECD countries.

At the same time, in an effort to improve the energy price-setting system, the Government will introduce a floating-rate system to reflect changes in the international prices of primary energy sources and exchange rates, and will completely deregulate the pricing of LPG.

3. Activation of the integrated resource planning system

Demand-side management (DSM) for electricity and natural gas can effectively bring about large-scale energy saving without causing inconvenience to consumers or the construction of new power-generation facilities. In addition, the Government is planning to make it mandatory to implement integrated resource planning, which seeks a balance between investments in energy supply facilities and investments in DSM for energy efficiency and conservation.

To achieve this objective, the Government will recommend that electricity and gas utilities include concrete DSM measures, together with an evaluation of their potential saving effects, when they establish long-term demand and supply plans. The Government also intends to compensate their DSM costs by adjusting the utility rates or by offering tax incentives.

4. Establishment of energy-efficient transport and logistics systems

The DSM concept will also be applied to the transport sector. In developing new towns and industrial estates, serious consideration should be given to minimizing in advance the potential transport demand resulting from the economic activities in a city or in an industrial zone.

To enhance transport efficiency, distribution centres will be established in various regions, and related regulations and policies will be modified accordingly.

5. Activation of partnership programmes

The Government will help provincial administrations to establish regional energy plans and promote energy efficiency partnership programmes with social organizations, private companies and schools. Particular emphasis will be placed on the maximization of natural energy utilization to engage in the Eco-City projects.

ANNEX: PRINCIPAL ACTORS IN ENERGY EFFICIENCY

The following are the principal government participants in developing and delivering energy efficiency policies and programmes. Others, such as KEPCO and KGC, are also involved to varying but limited degrees.

Ministry of Trade, Industry and Energy

The Energy Policy Office in the Ministry of Trade, Industry and Energy is responsible for energy policy. Within this office, the Energy Conservation Policy Division is responsible for energy conservation and efficiency planning and policy development. To pursue these tasks effectively, the Ministry supervises, as mandated by the relevant laws, and collaborates closely with KEMCO, KEPCO, RaCER, KIER and KDHC.

Korea Energy Management Corporation

KEMCO is the government agency in charge of implementing the energy efficiency and conservation policies and programmes established by the Ministry. KEMCO was established in 1980, as mandated by the Rational Energy Utilization Act. It reports directly to the Energy Conservation Policy Division and must receive annual approval for its expenditure. KEMCO also participates in the development of policies and programmes through its interaction with the Ministry.

KEMCO has a wide range of programmes in almost all of the major end-use sectors. These programmes fall under the following general areas:

- ❑ Energy audits and technical guidance
- ❑ Research, development and demonstration
- ❑ Education, training and information services
- ❑ Management of energy-using equipment and appliances
- ❑ Financial and technical support to R and D and efficiency investments
- ❑ Coordination and promotion of new and renewable energy R and D
- ❑ Total energy supply, i.e. co-generation and district heating projects

KEMCO has a staff of 750 in its main office in Seoul, 12 branches, and three separated centres: the Urban Mass Energy Supply Centre and the R and D Management Centre for Energy and Resources (RaCER) both in Seoul, and the Industrial CHP Centre in Taejon. Technical personnel account for 60 per cent of the total staff of these. The combined annual budget is about $25 million, of which about 70 per cent comes from the Government and the balance from revenues for services rendered.

Korea Energy Economics Institute

KEEI conducts basic research on conservation and energy efficiency policy for the Government. Most of the data and statistics in this field used by the Government in formulating its short- and long-term conservation policy is collected or synthesized by KEEI. It provides comprehensive national energy data, including the Yearbook of Energy Statistics, to the central and local governments. It also conducts socio-economic evaluations of existing conservation policies, and recently developed a series of energy efficiency and materials savings policy recommendations.

Korea Institute for Energy Research

KIER was formally established in 1981, although its history dates back to 1977. It is the main energy technology research institute in the Republic of Korea. It is funded by the Ministry of Trade, Industry and Energy directly and indirectly (i.e. through the RaCER) and by industry. It has 350 employees, of whom 270 are researchers. The Ministry and RaCER both provide advice on their research priorities to KIER. The final decision on priorities is made by the Government's Economic Planning Board. KIER is divided into two principal divisions: the Energy Conservation Research Centre and the Alternative Energy Research Centre. The latter is further divided into the Combustion Equipment, Building Energy and Industrial Energy Research Departments. There is also an Energy Technology Policy Division which conducts analysis for the purpose of setting priorities in research and development activities, as well as an Energy and Environment and Technical Information Department. KIER is the agency which develops building and appliance standards on behalf of the Ministry and KEMCO.

Korea District Heating Corporation

KDHC was created by the Government in 1985 to promote district heating in the Republic of Korea. It was restructured as a public corporation in May 1992 based on the Integrated Energy Supply Act. Shares are held by KEPCO (48.3 per cent), KEMCO (26.1 per cent) and the City of Seoul (25.6 per cent). KDHC is the largest "district heat utility" in the country.

The private sector and local governments can participate in the district heating business. The Government, through KDHC, supports district heating schemes through the provision of loans on favourable terms from the Petroleum Business Fund. KDHC started supplying district heating to southern Seoul in 1987. There are currently seven district heating systems, all built within the past 10 years, and 6 of these are owned and operated by KDHC. At present, about 4 per cent of the heating market is supplied by district heating. The Government's objective is to increase this figure to 15 per cent nationwide by 2001.

XVI. MALAYSIAN ENERGY INFRASTRUCTURE*

INTRODUCTION

In this paper, an attempt will be made to describe the energy infrastructure in Malaysia, outlining the energy demand in the country and the supply situation in terms of crude oil, natural gas, coal, hydro and electricity.

A. OVERVIEW

1. General trend

As Malaysia moves towards achieving the aims of its Vision 2020, it is envisaged that its economy will double itself every 10 years over the three decades from the 1990s. The Malaysian economy is targeted to grow at 7 per cent a year in the decade of the second Outline Perspective Plan (OPP2, 1991-2000). In actual fact, during the eight years since 1988, the economy's performance has been even more impressive, with a sustained high annual growth rate of 8.9 per cent. To achieve this target, the Government realizes that it is important for the energy requirements to be well planned and not become a constraint on this growth.

During the sixth Malaysian plan period (1991-1995), the energy sector played a significant role in the rapidly expanding industrial sector and contributed to government revenue as well as increased export earnings. During this period, the focus of the sector was to ensure adequate and reliable supplies of energy as well as to utilize the resources efficiently while recognizing the environmental considerations. The strategy was to move towards reduction in the dependence on oil as an energy resource, and this resulted in the rapid development of environment-friendly natural gas. The period also saw the privatization and subsequent restructuring of the electricity supply sector. A number of independent power producers (IPPs) were licensed to introduce competition in the generation subsector of this industry. At the same time, initial efforts were made to conserve the nation's energy resources through the development and promotion of efficient systems, processes, equipment and buildings.

2. Energy demand

The final consumption of commercial energy grew at an annual rate of 8.6 per cent during the period 1991-1995, as shown in table XVI.1, in tandem with the rapid growth of the manufacturing and transport sector. The energy intensity of the economy increased from 6.96 GJ or 0.166 tons (TOE) per thousand ringgits of GDP in 1970 to 7.07 GJ, or 0.169 TOE per thousand ringgit of GDP in 1995. The final consumption of gas, coal and electricity grew at 17.8, 13.3 and 12.8 per cent a year respectively.

As shown in table XVI.2, the transport sector was the largest consuming sector and accounted for 39.1 per cent of the total commercial energy demand in 1995, followed by the manufacturing sector

Table XVI.1 Final commercial energy demand by source, 1990-2000

Source	*1990*		*1995*		*2000*		*Average annual growth rate (%)*	
	PJ	*%*	*PJ*	*%*	*PJ*	*%*	*6 MP*	*7 MP*
Petroleum products	414.0	74.9	561.7	67.1	777.5	60.8	6.3	6.7
Natural gas	45.7	8.3	103.5	12.4	188.1	14.7	17.8	12.7
Electricity	71.8	13.0	131.4	15.7	221.8	17.3	12.8	11.0
Coal and coke	21.5	3.9	40.1	4.8	92.0	7.2	13.3	18.1
Total	553.0	100.0	836.7	100.0	1 279.4	100.0	8.6	8.9
Per capita consumption (GJ)	29.9		41.1		56.1		6.6	6.4

* Francis Xavier Jacob, Principal Assistant Director, Electricity Regulation Division, Department of Electricity and Gas Supply, Malaysia.

Table XVI.2 Final commercial energy demand by sector, 1990-2000

Sector	*1990*		*1995*		*2000*		*Average annual growth rate (%)*	
	PJ	*%*	*PJ*	*%*	*PJ*	*%*	*6 MP*	*7 MP*
Agriculture and forestry	32.8	5.9	52.7	6.3	63.4	5.0	9.9	3.7
Mining and quarrying	25.7	4.6	34.4	4.1	50.0	3.9	6.0	7.8
Manufacturing	187.8	34.0	298.7	35.7	488.7	38.2	9.7	10.3
Transport	220.9	39.9	326.7	39.1	490.1	38.3	8.1	8.4
Commercial	23.9	4.3	34.7	4.1	53.3	4.2	7.7	9.0
Residential	43.4	7.8	51.5	6.2	64.4	5.0	3.5	4.6
Non-energy	18.5	3.3	38.0	4.5	69.5	5.4	15.5	12.8
Total	**553.0**	**100.0**	**836.7**	**100.0**	**1 279.4**	**100.0**	**8.6**	**8.9**

Table XVI.3 Primary commercial energy supply by source, 1990-2000

Source	*1990*		*1995*		*2000*		*Average annual growth rate (%)*	
	PJ	*%*	*PJ*	*%*	*PJ*	*%*	*6 MP*	*7 MP*
Crude oil and petroleum products	520.2	71.4	746.1	55.3	943.2	49.4	7.5	4.8
Natural gas	114.4	15.7	456.4	33.8	793.9	41.6	32.0	11.7
Hydro	38.3	5.3	52.8	3.9	53.5	2.8	6.6	0.3
Coal and coke	55.5	7.6	93.2	7.0	117.9	6.2	10.9	4.8
Total	**728.9**	**100.0**	**1 348.5**	**100.0**	**1 908.5**	**100.0**	**13.1**	**7.2**

at 35.7 per cent. With the total of motorized vehicles growing at about 7.0 per cent a year, energy demand in the transport sector grew at about 7.0 per cent a year during the period. Energy demand by the manufacturing sector increased at an annual rate of 9.7 per cent during the same period.

3. Energy supply

The supply of primary commercial energy increased at an annual rate of 13.1 per cent during this period, as shown in table XVI.3. The dependence on crude oil and petroleum products declined, indicating the success of the country's four-fuel diversification policy, from 71.4 per cent in 1990 to 55.3 per cent in 1995. At the same time, the share of natural gas increased from 15.7 to 33.8 per cent. This increased supply can be attributed to accelerated production activities to meet the increasing demand in the electricity and non-electricity sectors.

(a) Crude oil

Malaysia's reserves of crude oil increased by about 41 per cent from 2.9 billion barrels to 4.1 billion barrels during the period. In line with the National Depletion Policy, which aims to prolong the producing life of crude oil reserves, production averaged about 631,000 barrels per day (bpd). Actual production increased from 601,000 bpd in 1990 to 664,000 bpd in 1995. The higher production in 1995 was mainly due to the better production performance of existing fields.

Domestic crude oil, which has a low sulphur content and is considered to be of premium quality, was largely exported. Nevertheless, the export volume decreased from 463,000 bpd in 1990 to 399 bpd in 1995, commensurate with the increased intake by local refineries.

The domestic crude oil refining capacity increased by 72 per cent to 356,000 bpd with the coming onstream of a 100,000-bpd capacity refinery in 1994 and the expansion of existing refineries. The amount of oil refined locally was approximately 16 million tons in 1995. With the increase in domestic crude oil refining capacity, the country moved towards self-sufficiency in the production of petroleum products such as fuel oil, diesel and petrol.

(b) Natural gas

Malaysia's natural gas reserves amounted to about 85 trillion cubic feet (TCF) in 1995. Of this, 83 per cent was non-associated gas. The production of natural gas almost doubled, from 1,865 million standard cubic feet per day (MSCFD) in 1990 to 3,476 MSCFD in 1995.

During the period, there was a marked increase in the utilization of gas, particularly for electricity generation and export. The methane component was transmitted through the gas pipeline system to the east, south and west of the peninsula and also exported to Singapore. Other components, ethane, propane and butane, were used as feedstock by several petrochemical industries producing, among others, methyl-tertiary-butyl-ether (MBTE), ethylene and propylene. The bulk of the natural gas produced off the coast of Sabah was utilized by the methanol and hot briquette iron plants as feedstock. Gas produced off Sarawak was used to produce LNG for export.

To further diversify gas utilization, it was promoted as a fuel for vehicles. Under the natural gas for vehicles (NGV) promotion programme, the fuel was exempted from excise duty, making its retail price at the pump half that of premium petrol. In addition, the conversion kits that allowed petrol engines to use gas were exempted from import duty and sales tax. During the period, six NGV stations were constructed in the Klang Valley and one in Miri. Gas was also reticulated to industries and commercial outlets as well as residential areas.

To ensure sustainable development of the gas sector, a long-term utilization limit of 2,000 MSCFD was adopted for peninsular Malaysia. Of this, 1,300 MSCFD is for electricity generation, with the rest being used as feedstock for petrochemical industries as well as for export to Singapore.

The major gas infrastructure project undertaken during the period was the M$ 3.3 billion Peninsular Gas Utilization project.

(c) Coal

During the period, the National Mineral Policy was formulated to facilitate and expedite the expansion and diversification of the sector as well as to ensure the effective and efficient development and management of the country's mineral resources, including coal. The total coal resources at present amount to about 982 million tons. Proven reserves as at 1995 were about 175.5 million tons, 97.3 per cent of which was in Sarawak and the rest in Sabah. Although the cost of production was relatively competitive, the high cost of transport, owing to the relative inaccessibility of coal areas, constrained further mining activities. The production from existing mines more than doubled, from 98,600 tons in 1990 to 200,000 in 1995.

In line with the four-fuel diversification policy, the use of local coal as an energy source was encouraged. About 65 per cent of the coal produced in 1995 was blended with imported coal for use at the Sultan Abdul Aziz power station in Kapar, Selangor. While coal exports increased slightly from 26,000 tons in 1990 to 35,000 in 1995, domestic requirements continued to be met by imports, which increased from 1.8 million tons in 1990 to 2.4 million tons in 1995. Apart from electricity generation, the other major user of coal was the cement industry.

(d) Hydropower

The estimated gross hydropower potential of the country was about 29,000 MW at the end of the period. Of this, 1,414 MW had been developed as at 1990, involving large plants such as the 400 MW Kenyir hydroelectric project and mini hydros ranging from 100 kW to 10 MW. About 69 per cent of the undeveloped hydropower potential is in Sarawak and about 17.2 per cent in Sabah. During the period, an additional 70 MW of hydropower was commissioned at Sungai Piah, Perak. Construction work on the 600 MW Pergau hydroelectric project continued during the period. The total electrical energy generated by hydropower increased from 4,001 GWh in 1990 to 4,424 GWh in 1995. However, the share of hydropower in the total electricity generated declined from 17.6 to 10.6 per cent in the period.

(e) Electricity

Electricity demand grew at about 12.8 per cent a year during the period. This was met by new capacities installed by the three major utilities as well as IPPs. A total of 5,535 MW of new generation capacity was added to the National Electricity Company (TNB) system in peninsular Malaysia. Of these new capacities, 51 per cent was from the utility and the rest IPPs. The reserve margin of the TNB system declined from about 33 per cent in 1990 to 18 per cent in 1993, and subsequently increased to about 61.1 per cent in 1995, as shown in table XVI.4.

Table XVI.4 Generation capacity (MW), 1990-2000

Year	*Generation by system*	*Total installed capacity*	*Peak demand*	*Reserve demand (percentage)*
1990	TNB	4 576	3 447	32.8
	LLS	303	204	48.5
	SESCO	363	194	87.1
	Total	**5 242**	**3 845**	**36.3**
1995	TNB	10 111	6 276	61.1
	LLS	671	323	107.7
	SESCO	645	377	71.1
	Total	**11 427**	**6 976**	**63.8**
2000	TNB	13 548	10 448	29.7
	LLS	960	555	73.0
	SESCO	985	692	42.3
	Total	**15 493**	**11 695**	**32.5**

The installed generation capacity of the Sabah Electricity Board (LLS) rose by 17.2 per cent from 303 MW in 1990 to 671 MW in 1995. The electricity supply system in LLS remained largely unintegrated during the period. Peak demand for electricity in Sabah increased by 9.6 per cent a year from 204 MW to 323 MW over the period. IPPs have also been introduced in Sabah to help meet the demand.

The generating capacity of the Sarawak Electricity Supply Company (SESCO) increased by 12.3 per cent a year and the peak demand by 14.2 per cent a year. In 1995, SESCO installed capacity stood at 645 MW, while demand was at 377 MW.

In line with the four-fuel policy, the use of gas for electricity generation in the country increased from 26.2 per cent in 1990 to 68.4 per cent in 1995. With this, the share of fuel oil declined from 41.9 per cent in 1990 to 11.2 per cent in 1995.

Along with the increase in the generating capacity, the transmission networks were expanded both to improve the coverage and to enhance system reliability and stability. TNB expansion of the transmission system involved the laying of 5,029 circuit kilometres (cct-km) of 275 and 132 kV lines and the phasing out of 66 kV lines from 892 cct-km in 1990 to 274 cct-km in 1995, as shown in table XVI.5. In addition, TNB began implementation of its 500-kV transmission project in 1995.

During the period, LLS completed the 33 kV Tuaran transmission system and initiated the 33-kV line from Patau-Patau to Sungai Beradun and its associated sub-stations. In Sarawak, a 198-km, 275-kV transmission line linking Bintulu to Miri, and a 56-km, 132-kV line from Kemantan to Tanjung Manis, were undertaken.

Table XVI.5 Transmission network capacity (cct-km), 1990-2000

Year	*Utility*	*500 kV*	*275 kV*	*132 kV*	*66 kV*
1990	TNB	0	3 596	6 107	892
	LLS	0	0	479	54
	SESCO	0	327	46	0
1995	TNB	0	4 881	9 851	274
	LLS	0	0	479	82
	SESCO	0	569	63	0
2000	TNB	1 112	5 493	11 594	0
	LLS	0	640	1 421	132
	SESCO	0	767	128	0

The distribution network of the utilities comprises 33, 22, 11 and 0.415 kV lines. The TNB network increased from 25,765 cct-km to 44,276 cct-km, and the LLS network from 2,850 cct-km to 3,555 cct-km over the period, as seen in table XVI.6. SESCO increased the network by 1,351 cct-km.

Table XVI.6 Distribution network capacity (cct-km), 1990-2000

Year	*Utility*	*33 kV*	*22 kV*	*11 kV*	*Total*
1990	TNB	2 656	1 845	21 264	25 765
	LLS	70	280	2 500	2 850
	SESCO	736	0	2 769	3 505
1995	TNB	3 647	2 432	38 197	44 276
	LLS	105	350	3 100	3 555
	SESCO	1 192	0	3 664	4 856
2000	TNB	5 286	3 162	68 755	77 203
	LLS	140	400	4 000	4 540
	SESCO	1 500	0	6 500	8 000

By the end of the period, 92 per cent of rural households were served with electricity, compared with 80 per cent in 1990, as shown in table XVI.7. Of the total expenditure on rural electrification by the federal Government, 87 per cent was for grid extension projects and the remainder for stand-alone projects involving the installation of diesel generators and solar-powered systems.

Table XVI.7 Rural electrification coverage by region, 1990-2000

Region	*1990*	*1995*	*2000*
Peninsular	91	99	100
Sabah	48	65	75
Sarawak	50	67	80
Malaysia	80	92	93

(f) Non-conventional energy

Malaysia is endowed with non-conventional renewable energy resources such as biomass, solar and wind. The utilization of these grew at 7.4 per cent a year, from 92.5 PJ in 1990 to 132.3 PJ in 1995. A large portion of these resources consisted of biomass, namely oil palm waste and wood waste, used to produce steam for processing activities and to produce electricity. During the period, a pilot wind-based plant with a capacity of 150 kW was installed on an island off Sabah. Thirty-two projects to generate electricity using solar technologies, benefiting about 800 rural households, mainly in Sabah and Sarawak, were also implemented in this period.

B. FUTURE OUTLOOK AND ISSUES

1. General trend

For the seventh plan (1996-2000), concerted efforts will be made to ensure that the development of energy resources will continue to contribute to the nation's economic growth and well-being. The emphasis will be on the sustainable development of depletable resources as well as the continued diversification of energy sources. In the electricity sector, with the generation capacity aspects being well taken care of, the focus will be on expanding and upgrading the transmission and distribution infrastructure.

Since long lead times are associated with energy projects before they come onstream, long-term planning will be emphasized. With the aim of improving the energy sector operations, there will be an ongoing exercise to promote higher productivity and efficiency. In order that the competitive edge of the nation is sustained and improved, the quality, reliability and efficiency of the energy supply system and services will be upgraded continually.

2. Energy demand

Over the seventh Malaysian plan period, the overall demand for commercial energy is expected to increase at an annual rate of 8.9 per cent to 1,279.4 PJ in 2000, while the energy intensity of the economy is anticipated to increase to 7.34 GJ, or 0.175 TOE per thousand ringgit of GDP. This reflects the increase in more energy-intensive industries as well as the rising affluence of the population per capita consumption is expected to increase to 56.1 GJ in 2000.

Electricity demand is projected to grow at 11 per cent a year, increasing its share of total energy demand to 17.3 per cent in 2000. Per capita electricity consumption is expected to be 2,800 kWh at that time. At the same time, petroleum products are expected to decline to 61 per cent of total commercial energy demand in line with the fuel diversification policy.

The transport and manufacturing sectors are expected to be the main energy-consuming sectors, with about 38.3 per cent each of the total consumption.

3. Energy supply

Security of energy supply will be ensured through a prudent fuel mix based on domestic resources. The exploration and production of depletable energy resources, as well as the harnessing of the energy potential of renewable resources, are expected to continue.

(a) Crude oil

To increase the country's crude oil reserves, exploration activities will continue, especially in deepwater areas. During the period, the production of crude oil will average about 606,000 bpd, while that of condensate is expected to be about 89,000 bpd. About 43 per cent of the total volume produced is expected to be exported, with the rest refined locally. The country is expected to attain self-sufficiency in refining capacity with the commissioning of the second 100,000 bpd refinery in Tangga Batu, Melaka, in 1997.

(b) Natural gas

The production of gas during the period is expected to increase to 6,238 MSCFD by 2000. By then, about 1,300 MSCFD, or 65 per cent of the methane produced in Terengganu, is expected to be used for electricity production, with the rest being exported to Singapore as well as being used by domestic industries as fuel or feedstock. In Sabah, the period will see the increasing use of the gas for electricity generation, while in Sarawak, petrochemical industries and electricity generation are expected to increase.

About 250 km of pipelines will be constructed in the Klang Valley to cater for industrial, commercial and residential consumers as well as NGV retailing stations.

(c) Coal

In the context of least-cost planning, coal is expected to play an increasing role during the period. About 90 per cent of the 5.5 million tons required annually by the country will be met by imports. Local production is expected to increase to 510,000 a year by 2000. Two coal-fired electricity generating plants, a 1,000-MW plant in Klang, Selangor and a 100-MW plant in Sejinkat, Sarawak are expected to be commissioned by then.

(d) Hydropower

The Pergau hydroelectric project will increase the energy generated by hydro resources to about 5,204 GWh a year during the period. The construction of the 2,400 MW Bakun hydroelectric project will continue during the period. This installation is expected to supply annually 12,850 GWh of energy to the peninsula and 875 GWh to the SESCO system, or an equivalent of around 1,600 and 100 MW respectively in terms of firm capacity. The completion of this project will begin the proposed integration of the electricity supply system of the peninsula, Sarawak and Sabah. The 165-MW Liwagu hydroelectric project in Sabah is expected to be completed during the period.

(e) Electricity

During the period, the needs of the nation will be adequately met with the generating capacities of the utilities and IPPs. Greater emphasis will be given to the expansion and upgrading of the transmission and distribution networks.

Rural electrification programmes during the period will comprise grid extensions and the provision of stand-alone generators using solar, micro and mini hydros as well as various hybrid stations. By the end of the period, about 93 per cent of the rural areas are expected to be electrified.

(f) Non-conventional energy

The consumption of non-conventional energy is expected to decline to 124.2 PJ in the year 2000. This will be due to the increasing substitution of biomass by gas and electricity. Other forms of renewable energy, such as solar, micro hydros and hybrid systems, are expected to increase.

C. POLICY OPTIONS

1. Privatization of the energy supply sector

Building on the earlier success of the privatization of the energy supply sector, the private sector is expected to be increasingly entrusted with such projects in the future. In the electricity sector, generation capacity is expected to be developed by the utility and IPPs in the approximate ratio of 70:30. In Sabah, LLS is expected to be privatized soon. The Government's share in SESCO is gradually being reduced.

Privatization will reduce the financial burden of the Government in implementing energy infrastructure projects. It will also be a stimulant for economic growth, in line with the governments plans for the private sector to contribute towards meeting development goals. It is also expected to increase productivity and efficiency as the sector is open to more market forces.

2. Productivity improvements

Energy efficiency in the production of primary energy, conversion of primary energy to secondary energy, transmission of energy and the final utilization of energy will be improved. Given the labour shortage in the country, capital intensity and automation will be promoted, resulting in greater use of electricity. This is expected to enhance the competitiveness of Malaysian exports. In the long term, as demand for energy grows, the country is expected to become a net importer of energy, thereby adversely affecting the balance of payments. Thus, energy-efficiency improvement measures are imperative.

3. Environmental considerations

With a view to reducing the negative impacts of harnessing and utilizing energy resources on the environment, environmental considerations will continue to be considered in energy planning and policy formulation. The use of hydro resources in generating electricity will be given increasing emphasis. The use of natural gas, which is environment-friendly, will be promoted aggressively in the transport and manufacturing sectors. In addition, electric-based urban public transport systems will be further expanded.

4. Energy pricing

Pricing policies will be directed at ensuring that energy prices reflect the economic cost or true cost of supply, are able to raise revenues for the sector's development as well as remain competitive to encourage the diversification of energy resources into greater use of indigenous resources. With regard to electricity pricing, the availability in adequate quantity and quality and at reasonable prices is necessary for the promotion of industrial development. Towards this end, efforts will be made to ensure stability in electricity tariffs at acceptable and internationally competitive levels. At the same time, the needs of power utilities to generate sufficient revenues for future development plans will be taken into account.

For electricity, the tariff mechanism used was in the form of a formula based on:

$$\mathbf{CPI - M - Y,}$$

where

CPI is the consumer price index set annually,

M is the efficiency factor set every 4 years, and

Y is the fuel cost pass through factor and to take into account energy purchased from IPPs

After about one and a half years of use of this formula, it was suspended pending further review.

The retail prices of several petroleum products continue to be determined by the automatic pricing mechanism, which takes into account costs, taxes and the prevailing ex-refinery product prices in Singapore. Despite constant fluctuations in the Singapore prices, domestic retail price stability is maintained by varying the tax imposed on the products.

Gas supplied for electricity generation as well as reticulation in the peninsula is pegged to medium fuel oil prices quoted in Singapore. Industries and other bulk users negotiate prices on a case-by-case basis. The price of gas in Sabah is based on netback computations, while the LNG from Sarawak is linked to the price of a basket of crude oils imported for domestic consumption in Japan.

D. CONCLUSIONS

The energy sector will continue to play an important role in the development and expansion of the other sectors of the economy. Concerted efforts will be made to increase the productivity and efficiency of the energy sector to ensure that energy of the required quantity and quality is supplied at reasonable prices. With the inevitable increase in electricity tariffs, the supply quality will be under pressure to be improved. Environmental considerations will continue to be factored in energy policies.

XVII. ENERGY INFRASTRUCTURE AND PRICING POLICIES: PAKISTAN*

INTRODUCTION

The energy infrastructure plays a very important role in term of fulfilling the energy requirements of a country. In the context of the overall energy system, its role is critical, from upstream activities such as exploration/production to the level of downstream activities, such as transmission and distribution to the final end-consumers. In terms of broad definitions, the upstream activities relate to the development of energy resources, such as exploration/production of coal, oil and gas, hydroelectric and nuclear plants, the installation of renewable energy resources and supply sources of rural energy. The infrastructure of downstream activities, which can be recognized as energy industry, covers installations such as thermal power capacity, power transmission and distribution lines, including grid stations, oil and gas transport and distribution lines, including purification plants, petroleum refineries, oil transport, distribution and storage networks and port facilities for handling imports/exports of energy products. Another area which cannot be ignored, especially in the case of Pakistan, is the infrastructure relating to the downstream activities of rural energy (which is still the single largest source for meeting overall energy demand), such as the transport and distribution network of rural energy, i.e. woodfuel etc.

The present paper reviews the energy infrastructure development and energy pricing policies in the historical perspective; it also analyses the ongoing changes in this area and tries to identify options and policies for future infrastructure development. In the next section a review of demand supply analysis has been made along with the Government of Pakistan pricing policies and the energy infrastructure development undertaken until recently. It also contains a detailed commentary on the energy infrastructure and evolving trends therein. Section B looks into the future of energy infrastructure in the light of demand supply projections and identifies the potential bottlenecks and issues vis-à-vis the Government's ongoing pricing policies and privatization programme. Section C summarizes the policy options available to address the above issues. The conclusions and recommendations are given in section D.

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A. OVERVIEW OF THE ENERGY SECTOR

1. Energy resources

The commercially exploitable energy resources of Pakistan consist of hydropower, natural gas, oil and coal. In addition, the country has a large base of traditional fuels in the form of fuelwood, agriculture and animal waste. Despite its own energy resources of a fairly large size, Pakistan's dependence on energy imports has been higher than envisaged by the Government in the previous 10 years, particularly due to financial and implementation constraints.

Hydropower. Pakistan's hydropower potential is estimated at about 27,000 MW, of which only 4,826 MW has been utilized (table XVII.1). Besides the Ghazi Barotha hydro project of 1,400 MW, no other major hydro project is expected in the near future. Feasibility studies of two major hydro projects, Kalabagh (3,600 MW) and Basha (3,300 MW), have been completed and the projects appear to be economically attractive; however, they have not been developed owing to political and environmental constraints.

Table XVII.1 Hydropower potential and remaining reserves

(MW)

Potential	*Utilized*	*Remaining reserves*
27 000	4 825	22 175
100%	18%	82%

Source: Pakistan Economic Survey, 1995-1996.

Oil. In the oil subsector the remaining recoverable reserves as on 30 June 1996 amounted to about 29.51 million tons of oil equivalent (MTOE); however, future exploration in the less explored areas and offshore could change this estimate considerably. With 57,549 barrels/day production in 1995/96, the resulting reserves to production ratio is only

Table XVII.2 Reserves as on 30 June 1996

(Millions of TOE)

Fuel	*Original recoverable*	*Cumulative production*	*Balance recoverable*	*Production rate*	*Depletion time*
Crude oil	74.87	45.36	29.51	2.82	10.5 years
Natural gas	568.32	212.29	356.03	13.72	26 years
Associated gas	18.52	11.70	6.81	0.40	17 years

Source: Energy Yearbook, 1996.

10.5 years, which calls for additional exploration activity (table XVII.2).

Gas. In the light of past experience, Pakistan is considered a gas-prone area. According to the latest available estimates, the remaining recoverable gas (mostly non-associated) reserves are estimated at 356 MTOE (*ibid.*). At present, gas production amounts to about 1,821 million cubic feet per day (14 million TOE) as compared with demand estimates of about 1,700-1,800 MCFD. With the current rate of production, the remaining reserves are likely to be exhausted in a shorter period of time. Despite recent discoveries, the rate of gas exploration has been slower owing to the lack of resources in gas exploration.

Coal. Domestic proven reserves of coal and lignite as of 1996 are estimated at about 734 million tons, out of which 432 million are recoverable mainly in Sindh Province of Pakistan. The present market is confined to providing fuel for brick kilns. The development of coal mines for power generation will depend on the quality of coal, mining costs and organizational constraints.

Biomass/renewable. Most of the renewable energy is obtained by the burning of biomass (wood, agriculture and animal waste), while the use of wind energy, solar energy and biogas remains insignificant. According to a household energy strategy study concluded in 1993, about 85 per cent of the household needs are met by biomass fuels.[1] The study also estimated that the total standing woodstock is about 210 million tons,[2] with an annual sustainable production of 23 million tons. Similarly, about 58 million tons of crop residues (principally wheat residue and cotton sticks) are available each year. The study also concluded that wood fuel markets in Pakistan have generally been competitive, although there are certain areas which are under the threat of deforestation, primarily owing to the shortage of timber stock. Details of biomass energy resources are given in table XVII.3.

Table XVII.3 Biomass energy resources

(Millions of tons)

Type	*Standing stock*	*Annual productivity*
Woody biomass	210.78	22.70
Cotton residue	–	12.46
Maize residue	–	3.47
Sugar cane	–	12.88
Rice residue	–	8.16
Animal waste	–	10.90
Wheat residue	–	20.65

Source: Biomass Resource Assessment; Household energy strategy study, 1991.

2. Energy demand

Commercial energy.[3] During the past five or six years, energy consumption in Pakistan has increased by about 6.4 per cent a year, owing mainly to a steady increase in gross domestic product (GDP) per capita, increased mechanization of agriculture, steady growth in manufacturing and a high rate of urbanization, besides aggressive government policies to extend commercial fuels like electricity and gas to new consumers at a subsidized rate. The sharpest increase was in oil consumption (7.4 per cent a year), followed by natural gas (6.3 per cent a year) and electricity (5.8 per cent) (table XVII.4). As regards the sectoral consumption, the industrial sector is the largest consumer of commercial energy (accounting for 37.7 per cent of total consumption in 1995/96), followed by transport (32.4 per cent), residential (20.6 per cent), agriculture (3.5 per cent), commercial sector (3.0 per cent), and others (2.9 per cent). Commercial energy consumption in all sectors grew at slower rates during the period 1991-1996 compared with 1983-1988, primarily reflecting the severe supply constraints of electricity and natural gas. Total delivered energy was 23.14 MTOE in 1995/96.

Traditional fuels. According to the household energy strategy study,[4] the household sector accounts for almost 90 per cent of total traditional fuel

[1] Government of Pakistan (1993).

[2] Garry Archer (1993).

[3] Government of Pakistan (1997b).

[4] Heaps and Oureghi (1993).

Table XVII.4 Final energy consumption by source

(Millions of tons of oil equivalent)

Source	1990/91	1995/96	Percentage growth
Oil[a]	7.80	11.20	7.40
Gas[b]	5.10	6.90	6.30
LPG	0.16	0.23	7.70
Coal	1.36	1.45	1.30
Hydroelectricity[c]	2.57	3.40	5.80
Total	**17.00**	**23.10**	**6.40**

Source: *Energy Yearbook, 1996.*

[a] Excluding consumption for power generation.

[b] Excluding consumption for power generation and feedstock for fertilizer production.

[c] @ 3,412 Btu/kWh, being the actual energy content of electricity.

Table XVII.5 Primary energy supplies

(Millions of tons of oil equivalent)

Source	1990/91	1995/96	Percentage growth
Oil[a]	10.80	16.50	8.70
Gas	11.00	14.10	5.00
LPG[b]	0.10	0.19	11.60
Coal	2.00	2.30	3.10
Hydroelectricity[c]	4.40	5.50	4.90
Nuclear electricity[c]	0.09	0.12	4.60
Total	**28.50**	**38.70**	**6.40**

Source: *Energy Yearbook, 1996.*

[a] Excluding petroleum products exports and bunkering.

[b] Including import and production from field plants.

[c] Converted at 10,000 Btu/kWh to represent primary energy equivalent of hydro and nuclear electricity as if this was generated by using fossil fuels.

consumption in Pakistan. In spite of the growth of modern fuel usage, the majority of households, especially in the rural areas, still rely on bio-fuels such as firewood, dung and crop residues. It is estimated that out of about 20 MTOE of energy consumed in the household sector, modern fuels account for only 3 MTOE (15 per cent), with traditional fuels accounting for the remainder (85 per cent) urban households account for about 70 per cent of the modern fuels used in the residential sector, and for about 15 per cent of the traditional fuels.

3. Energy supply

According to the energy balance for the years 1995-1996,[5] total primary energy supply stands at about 38.75 million TOE. Of this amount, about 24.33 million TOE (62.8 per cent) consisted of indigenous resources. The share of natural gas was 14.1 million TOE (36.4 per cent); the share of crude and petroleum products was 16.5 million TOE (42.6 per cent) and that of hydro and nuclear electricity was 5.6 MTOE (14.5 per cent) (for details, see table XVII.5).

Self-reliance vis-à-vis imports. As compared with 8.5 MTOE (29.8 per cent) in 1990/91, about 14.7 MTOE (39.7 per cent) were imported in 1995/96 in the form of crude oil for the domestically available refining capacity and petroleum products, principally diesel and furnace oil. In terms of energy supply, the contribution of domestic resources is falling behind and thus giving way to the imports. The level of petroleum product imports increased from 4.4 MTOE in 1990/91 to 10.3 MTOE in 1995/96 (see table XVII.6), despite an increase in domestic production of crude oil and petroleum products and hydroelectric power. As a result, the foreign exchange (US dollars) outflow associated with increasing energy imports increased from $1.7 billion in 1990/91 to $2.0 billion in 1995/96. Table XVII.7 provides the details. This could be attributed to inadequate investments in energy supplies, and irrational pricing policies for energy resources development.

Table XVII.6 Energy self-reliance trends

(Millions of TOE)

	1990/91		1995/96	
Energy type	Imports	Percentage share	Imports	Percentage share
Crude oil	4.1	22.8	4.4	17.6
Petroleum products	4.4	24.7	10.3	39.1

Source: *Energy Yearbook, 1996.*

Table XVII.7 Foreign currency outflow for energy

(Millions of US dollars)

Energy type	1990/91	1995/96
Crude oil	633	538
Petroleum products	1 087	1 471
Total	**1 720**	**2 009**

Source: *Energy Yearbook, 1996.*

[5] Government of Pakistan (1997b).

4. Emerging issues

The slower rate of energy supply can largely be attributed to the lack of proper investment in the energy infrastructure. This has been mainly due to the fact that most of the energy infrastructure in the country has been owned and operated by the public sector in Pakistan. Owing to persistent budget deficits, the Government has been finding it difficult to allocate the required resources in the energy sector to meet the growing requirements of energy. Although the share of energy supply investments in the overall investment of Pakistan has been increasing over the years; from 15 per cent in 1990/91 to about 21 per cent in 1995/96 (the volume of investment doubled from $1.2 billion to $2.5 billion in the same period; see table XVII.8 for details). However, this has not been sufficient to meet the energy investment requirements as a whole. The lack of full participation of the private sector in the energy sector points towards inappropriate energy pricing policies; which have not been so consistent as to attract the requisite infrastructure development in the private sector until recently. Despite some progress made in private power generation, the situation of constraints on supply in the coal, oil and gas sector is expected to continue in the foreseeable future unless some adjustments are made in energy-pricing policies.

Table XVII.8 Energy supply investment*

(Millions of US dollars)

	1990/91	*1995/96*
Energy supply investment	1 189	2 467
Percentage of total investment	15%	21.2%

Source: *Economic Survey, 1995-1996.*
* Including public and private sector investment.

5. Pricing policy

Energy consumer prices are regulated by the Government and do not necessarily reflect the cost of supply, especially for certain consumer categories which are subsidized at the expense of other consumers. This has encouraged higher growth in demand in the past. Similarly, most of the producers' prices reflect a cost-plus mechanism through which the producers are guaranteed a certain level of return over and above their costs, which leaves much to be desired as far as incentives for private producers are concerned. Against this background, the development in energy infrastructure lagged behind the fast-growing demand.

Recent developments in producers' prices. The Government has been gradually liberalizing energy prices, and generally moving towards more market-oriented and transparent regimes. The 1994 Petroleum Policy[6] introduced a more attractive market-based reference price for determining the domestic producer price of natural gas, and eliminated the discretionary discount applied by the Government on the border price of crude, for determining the producer price of domestically produced crude oil. As a result, producer prices for domestically produced crude continue to be pegged to international prices of crude, while the natural gas producer price is now indexed to the international price of a basket of crude oil. Refinery prices are directly linked to international market prices. Similarly, in the power sector, under private power policy,[7] a highly attractive bulk tariff (6.5 cents per kilowatt hour) has been offered to the private generating companies, which has already produced very encouraging results in terms of a sizeable capacity addition in the private sector.

Recent developments in consumer prices. The prices of petroleum products and natural gas have been periodically adjusted in line with movements in world market prices. As a result, current consumer prices for petroleum products are at or above the corresponding import prices, adjusted for inland transport and distribution margins. On average, during the period 1988-1995, prices of motor gasoline were been raised by about 10 per cent a year, kerosene 11 per cent a year, diesel 7.8 per cent a year, and fuel oil 6 per cent a year. Consumer prices of natural gas were also increased by about 25 and 26 per cent in mid-1996 and 1997 respectively. Despite the recent increase, gas tariffs for residential consumers are at about 80 per cent of the border price of fuel oil. Electricity tariffs, including the fuel adjustment surcharge, have been increased regularly, to enable the Water and Power Development Authority (WAPDA) to finance at least 40 per cent of its average investment programme through internal cash generation. As a result, the average electricity tariffs have risen from about PRs 0.64/kWh in 1984/85, to PRs 2.24/kWh in 1995/96.

6. Institutional set-up[8]

The energy sector, by and large, is owned and operated by the Government. The responsibility for

6 Government of Pakistan (1994c).

7 Government of Pakistan (1994d).

8 World Bank/Energy Wing, Planning and Development Division (1995).

the energy sector is shared by four ministries: the Ministry of Petroleum and Natural Resources, the Ministry of Planning and Development, the Ministry of Water and Power, and the Ministry of Production. A high-level Cabinet Committee is responsible for the review and approval of all plans, policies and projects in the energy sector, while the implementation of the approved projects is assigned to the respective ministries and entities. An Energy Review Group provides coordination among the entities and ministries and monitors the progress of ongoing projects, programmes, policy actions and issues. In addition, the Environment and Urban Affairs Division, is responsible for formulating and monitoring the implementation of Government's environmental policies, including those for the energy sector.

The day-to-day operations in the energy sector are shared by a number of public and some private sector entities. The public sector entities are (a) the Water and Power Development Authority (WAPDA), which is also responsible for the construction, operation and maintenance of power generation, transmission and distribution facilities throughout the country, except the Karachi area; (b) the Oil and Gas Development Corporation (OGDC), for the exploration and development of oil and gas; (c) the Pakistan Mineral Development Corporation (PMDC), for the exploration and development of mineral resources; and (d) the State Petroleum Refining and Petrochemical Corporation (PERAC) which owns the National Refinery Limited (NRL), for processing crude oil. Also involved in the energy sector are a number of semi-autonomous entities in which the Government has a controlling interest, either directly or through public institutions: (i) Karachi Electricity Supply Corporation (KESC), which is a vertically integrated utility in the Karachi area; (ii) Sui Northern Gas Pipeline Limited (SNGPL) and Sui Southern Gas Corporation (SSGC), responsible for the transmission and distribution of natural gas; (iii) two independent gas transmission networks which supply natural gas to the WAPDA Guddu Power Station and to three fertilizer plants; and (iv) Pakistan State Oil Limited (PSO), responsible for the marketing and distribution of petroleum products. Private sector entities include a large number of Pakistani coal mining companies and two refineries; two companies for the marketing and distribution of petroleum products, and a number of oil and gas development companies. The Ministry of Water and Power has jurisdiction over WAPDA and KESC, and the Ministry of Petroleum and Natural Resources over NRL and Pakistan Refinery Limited (PRL). All other operational entities (public and semi-autonomous) are under the jurisdiction of the Ministry of Petroleum and Natural Resources.

Against the backdrop of the above institutional set-up, the Government has overwhelming control over the energy sector, which has been cited as one of the impediments to this sector's development. However, the list of private sector entities has started growing in the wake of private power generation/transmission companies and with the privatization and corporatization of public entities.

7. Energy infrastructure (see annex)

Power infrastructure.[9] In the power sector, the main public sector utilities, KESC and WAPDA, are integrated through a 220-kV double-circuit transmission line. The generating capacity of KESC has increased over the years, from 1,138 MW in 1985/86 to 1,738 MW in 1995/96; similarly, in the WAPDA system, the generating capacity increased from 5,023 MW in 1985/86 to 11,094 MW in 1995/96. Out of the hydel capacity increased from 2,898 MW in 1985/86 to 4,826 MW in 1995/96. Furthermore, an additional capacity of 1,292 MW has been added for the first time in the private sector, which is likely to increase to a level of 4,293 MW by 1998. Similarly, the network of power transmission and distribution has expanded over the years, from 22,729 km of transmission lines and 206,975 km of distribution lines in 1990 to 27,229 km and 268,486 km respectively in 1995. There are 31,508 grid stations in WAPDA which increased from 12,400 in 1985/86. With the help of the above-mentioned system the WAPDA and KESC system support about 10 million consumers in the residential, commercial, industrial and agriculture categories. WAPDA accounts for about 84 per cent of the total installed capacity of 12,969 MW, while supplying about 80 per cent of the country's electricity consumption.

The Government of Pakistan has been pursuing a strategic plan in the power sector with the objective of (a) enhancing capital formation through private sources, (b) improving efficiency through competition, and (c) rationalizing electricity prices. This plan envisages a gradual transition of the power system from integrated state-owned utilities to a decentralized system with substantial private ownership and management and reflecting a commercial and competitive operating environment. Similarly, a

[9] Government of Pakistan (1996).

transmission line and the distribution of certain area electricity boards will be operated by the private sector.

Gas infrastructure. Pakistan has developed an extensive gas transmission and distribution network of more than 3,500 km of high-pressure trunk-lines to service the major centres of demand in the country's four provinces. Two principal gas transmission systems, the northern and southern systems, exist in Pakistan. The northern system, managed by SNGPL, supplies gas to the cities of Multan, Faisalabad, Lahore, Gujranwala, Islamabad and Peshawar from the Sui Gas field and other fields in the Pothwar area. The southern system, managed by SSGC, runs south from the Sui field to serve both sides of the Indus river valley and the major cities of Karachi and Hyderabad. SNGPL and SSGC together handle approximately two thirds of the volume of gas produced. A third, much smaller, system is essentially dedicated to evacuating gas for utilization in power generation and fertilizer production.

However, the transmission network is at present operating at its maximum capacity during the winter peak season. Any increase in gas supply requirements will necessitate expansion of the system. Although Pakistan ranks among the leading gas-producing developing countries, its gas reserves have not been adequately developed and exploited to meet the growing demand, for a variety of reasons: (a) the limited involvement of international companies owing, in part, to a lack of appropriate incentives; (b) the scarcity of public sector funds; and (c) delays in project implementation. This scenario is likely to change as the privatization of SNGPL and SSGC is in process. Besides, to attract more companies, an incentive-driven "return on equity-based" formula will be offered to new investors in this area.

Petroleum infrastructure.[10] Petroleum products play an important role in meeting the overall energy needs of Pakistan. In 1995/96, of the total consumption of about 23 MTOE, the share of petroleum products was 48.5 per cent. The daily production of crude and petroleum products falls short of the total daily requirement of crude and petroleum products and the deficit quantities of about 190,000 bpd being imported from the Middle East. The petroleum infrastructure supports the production, refining, storage, import, transport and distribution throughout the country.

Refineries. There are currently three refineries in Pakistan, the state-owned National Refinery Limited (NRL), and two privately owned refineries, Pakistan Refinery Limited (PRL) and Attock Refinery Limited (ARL). Of these, NRL and PRL are located in Karachi, have a maximum processing capacity of about 6 million tons a year, and rely primarily upon imported crude, even though the Lower Indus basin crude is also utilized to the maximum extent possible. ARL, at Rawalpindi, with a processing capacity of 1.6 million tons, is based on the indigenous crude. The three refineries produce a range of products based on their available configurations. While the production from the three refineries meets some of the national needs, large shortfalls occur for diesel, fuel oil, kerosene, and high octane blending component (HOBC), which are made up through imports. In the future, 13.4 million tons of additional capacity is being proposed. According to the new petroleum policy, any one can set-up a refinery on an import-parity pricing basis.

Ports. Imported crude oil and petroleum products are received at the oil terminals at Karachi Port and Port Qasim. Port Qasim is currently receiving imported fuel oil, which is conveyed to the Bin Qasim Power Plant of KESC nearby through a pipeline. Another facility at Port Qasim receives furnace oil and transports it to the private power plant at Hubco. At present there are constraints in the receipt, handling and storage of petroleum products at Karachi Port, which becoming major impediments to development in the sector. For a variety of reasons, investment in the above facilities at the port continue to lay behind optimal levels. At present, three operation oil piers (OPI, OPIV and OPV) can handle a bulk liquid cargo of a maximum capacity of 13.5 million tons. In addition, Port Qasim has proposed 7.2 million-ton capacity and associated storage tanks.

The transport of petroleum products is carried out according to a transport plan prepared by the Oil Companies Advisory Committee (OCAC); it intends to provide the least-cost transport, utilizing to the maximum extent possible the pipeline and the available railway wagons. Finished petroleum products are transported up country to major consumption centres by pipeline (35 per cent) rail (14 per cent) and road (51 per cent).

Road transport. The product movement through road transport of about 4.2 million tons in 1995/96 was primarily undertaken by private sector tankers supplemented by National Logistic Cell. About 7,500 private sector tankers, each having a carriage capacity

[10] Government of Pakistan (1997).

of 9,100 litres, are engaged in this business. Road transport is highly competitive and appears to work fairly smoothly, with no sign of any shortage of such transport.

Railways plays an important role in the transport of petroleum products from Karachi and Mahmood Kot near Multan to the province of Punjab and North West Frontier Province. It accounted for a product movement of about 2.6 million tons in 1995/96. The distribution companies own about 1,850 railway wagons, each having a carriage capacity of about 20 tons. In addition, Pakistan Railways has its own fleet of about 3,700 wagons. However, owing to a current turn-around time between Karachi and Multan of 10 days, which can be reduced to 7, the existing availability of rail wagons is therefore not sufficient to meet the demand.

Pipeline. The Pak Arab (PARCO) pipeline, completed in 1981, is the only major product pipeline in the country. It transports refined products from Karachi to mid-country storage at Multan for further distribution to the up-country locations by road and rail. The pipeline was designed for an initial capacity of 4.5 million tons per year (TPY), with two pumping stations. Currently, about 3.8 million TPY of products namely high-speed diesel and kerosene, are being moved through the pipeline system. The Company is planning to increase the capacity to about 6 million TPY by installing two additional booster pumps.

Distribution. Three major companies, Pakistan State Oil (PSO), Shell and Caltex have permission to distribute and market petroleum products. In 1994/95, the distribution companies marketed a total of 14.0 million tons. The state-owned PSO is the largest trading company, with a 76 per cent share of the market, followed by Shell (18.5 per cent) and Caltex (5.4 per cent) in 1994/95. Shell and Caltex have integrated interest in both refining and distribution in Pakistan. The companies appoint local private dealers to market their product through service stations/ retail outlets, besides selling directly to large industrial consumers and power stations and the aviation industry. The Ministry of Petroleum and Natural Resources controls the number of retail outlets, which has resulted in the expansion of the PSO outlets in far greater numbers than those of Shell and Caltex.

Storage. Karachi Port and Port Qasim support storage facilities of 80,000 tons and 30,000 tons respectively. Some 60,000 tons storage capacity is under construction at Karachi Port, and a dedicated storage of 160,000 tons is also under way for the pipeline to Hubco. Each of the three marketing companies have storage depots for different petroleum products close to the consumption centres. Products are received from refineries and through imports, and reserves maintained at the storage depots. As of July 1995, Oil Marketing Companies (OMC) total storage capacity was 467,846 tons. Filling facilities and bunkers for aviation fuels are present at major airports. Fuel oil is generally used by large consumers (cement plant, power stations), which create their own receiving and storage facilities. The storage maintained by refineries is around 618,050 tons. PARCO maintains a total storage capacity of 203,769 tons.

LPG bottling and distribution. Liquefied petroleum gas (LPG) is produced at the refineries, and at the gas fields in the Pothwar and Lower Indus basins. There are a number of companies in the country (Fongas, Burshane, Wakgas, Lifeline, Pakgas etc.), which are engaged in bottling and marketing operations. Each of the LPG marketing companies has its own network of distributors, where filled cylinders are sold and empty ones picked up. Since LPG supplies from gas fields fall short of domestic demand, the Government has allowed imports to fill the shortfalls. LPG bottling facilities were also created at Port Qasim, where most of the imports are received.

Fuelwood marketing infrastructure.[11] According to the findings of a wood-fuel marketing survey, about 40,412 businesses operate in fuelwood markets throughout Pakistan. Roughly 32 per cent are found in urban centres, 52 per cent in villages, and the remaining 16 per cent are located along metalled roads. In addition, about 4,800 timber traders also sell wood, though at lower levels. Retailers dominate the firewood market in numerical terms, totalling over 36,000, or 91 per cent of total. Sales to the household and commercial sectors comprise the bulk of their revenue. The Punjab and NWFP possess the highest representation of retailers. These provinces account for about 65 per cent of all retailers and 59 per cent of all traders. This heavy concentration can partly be attributed to the availability and proximity of wood supplies from private farms. Thus most of the wood trade is taking place in the northern part of the country. On an annual basis, fuelwood markets generated 16 million tons in sales volume during the year 1991/92, or roughly 135 kg per capita annually. About 12.4 million tons were sold to the final consumers, compared with 3.4 million tons sold to other traders.

[11] William Dougherty (1993).

About 71,848 people were working on a permanent basis during the winter of 1991/92. A further 26,928 people were employed as part-time staff. The study revealed that fuelwood markets in Pakistan operate under an organized set of arrangements and structures which are responsive to economic conditions. Trading networks are regulated by a number of interacting factors such as supply locations, transport requirements, alternative fuel availability, and purchase and selling prices. The transport of wood is a critical element of the firewood supply chain. High tonnages of firewood are transported over large distances in Pakistan, especially during the peak winter months. The most common form of transport is a six-wheel Bedford truck, although a variety of other mediums are used, such as tractor trolleys and animals. Average wood transport costs were estimated at Rs 0.53 per ton-km for a fully loaded eight-ton truck.

8. Regional cooperation

In Pakistan, the experience of regional cooperation in the area of energy infrastructure development has been minimal. The only project in operation is a 864-km long white oil pipeline from Karachi to Multan with a capacity of 4.5 million tons a year. This pipeline has equity participation of Pakistan and an Arab country. It plays a vital role in the transport of petroleum products from Karachi Port in the south to mid-country distribution centres. Besides other projects for regional cooperation, such as a natural gas pipeline from the Middle East/Central Asia, oil refineries etc. are in the planning stage and no concrete decision has yet been taken with regard to these.

B. FUTURE OUTLOOK AND ISSUES

1. Demand forecast

Base case. Some recent demand forecasts available with the Energy Wing, Planning and Development Division[12] are based on both elasticity and an end-use approach. For the base case forecast, the underlying macroeconomic framework assumes 6.5 per cent annual growth in GDP during the next 25 years, whereas energy price forecasts are based on (a) the World Bank forecast for petroleum products, (b) the import parity price for natural gas, and (c) LRMC-determined prices for electricity. According to the base case, final energy demand will increase from 30 MTOE in 1997/98 to 121 MTOE in 2018 within an average growth rate of about 7.2 per cent. For sectoral and fuel details, see table XVII.9. Much of the increase will be in the residential and industrial sectors (particularly for electricity and natural gas) mainly due to rapid urbanization, increasing access of the rural population to commercial fuel and sustained industrial growth. Rapid expansion in transport facilities would also imply a steep increase in petroleum products in the transport sector. The

[12] Government of Pakistan (1995).

Table XVII.9 Energy demand projections

(Thousands of tons of oil equivalent)

Sector/fuel	*1997/98*	*1997/98*	*2007/08*	*2007/08*	*2017/18*	*2017/18*
	High	**Low**	**High**	**Low**	**High**	**Low**
Households	4 678	4 544	10 728	9 534	25 179	16 957
Industry	11 587	11 174	23 492	21 229	51 149	38 111
Transport	8 326	7 286	15 390	12 391	28 523	19 497
Fertilizer	2 552	2 398	4 519	3 951	7 677	5 909
Agriculture	1 053	981	1 520	1 364	2 171	1 679
Commercial	1 431	1 399	2 842	2 677	6 033	4 679
Total	**29 626**	**27 782**	**58 492**	**51 145**	**120 732**	**86 832**
All sectors						
Electricity	4 538	4 540	11 008	10 208	27 035	19 249
Natural gas	9 297	8 969	21 054	18 771	48 310	34 754
Petroleum products	11 843	10 341	21 153	17 037	38 319	26 467
Coal	3 948	3 931	5 276	5 129	7 067	6 362
Power	**12 737**	**11 735**	**21 894**	**20 590**	**48 211**	**48 301**

Source: World Bank/Energy Wing, Planning and Development Division, Government of Pakistan, "Pakistan: Energy Options Study" (draft) (Washington, DC).

fuel demand pattern depicted by these projections indicates a shift from low-value traditional fuels to high-value modern fuels as the economy moves from low- to medium-income status. Details are provided in the table.

Low case. An alternate scenario envisages declining GDP growth from 5.5 per cent in the initial years to 4.5 per cent at the end of the period, and a higher price increase for petroleum products in the future than the base case. Under this scenario, the final energy consumption is projected to increase at an annual rate of about 5.8 per cent, which is equivalent to a difference of about 34 MTOE by 2018 compared with the high GDP/low price base-case scenario. Consequently, the energy demand in the residential and transport sector declines by about 46 to 48 per cent; by about 34 per cent in the industrial sector and by about 29 per cent in the agriculture sector relative to the base scenario. The overall final energy demand will increase from 27.8 million TOE in 1997/98 to 86.8 million TOE in 2018 (details are provided in table XVII.9).

The fuel requirement by the power sector for generating and distributing the demand level of electricity has also been worked out for both high and low GDP scenarios with no constraints on the supply of oil or gas and limited availability of hydel power.

2. Energy supply

Supply forecast. The supply forecast has been made by using the Oil and Gas Supply Model of the Energy Wing, which takes into account the important exploration, production and financial aspects. The driving parameters in the model are (a) the number of wells to be drilled in a particular year (b) the success ratio in each area (c) the probability of discovery (d) the size of the discovery (e) the lead time before full production (f) the depletion rate and life of the field, and (g) the cost of exploration and drilling. In terms of output, this model provides outputs such as the number of fields discovered, the production from each field and the investment requirements per year.

Energy balance. The energy balances,[13] based upon supply and demand (high- and low-growth scenarios) projections and fuel requirements for power generation and other transformation, indicate heavy dependency on imported fossil fuels. This import dependency is expected to increase from the present 35 per cent of total primary supply to 74 and 64 per cent under the high- and low-growth scenarios respectively in 2018. As indigenous crude oil and natural gas availability is limited, the country would continue to import energy in the form of oil, natural gas or coal, and this increasing dependence on imported fuel supplies could be a matter of great concern. Large investments will also be required for revamping the logistic infrastructure (port, transport and storage facilities) for handling this increased volume of imports.

3. Investment requirements

Under the low and base demand scenarios, total energy investments[14] for 1998-2018 are estimated to be in the range of PRs 2,573-3,225 billion at 1992/93 constant prices, at an average annual rate of PRs 129 billion to PRs 161 billion ($3.0 to $4.1 billion). Out of these, 57-64 per cent of the investment will be in the power sector, 39-33 per cent in oil and gas and the remaining 3-4 per cent in coal development. Details are provided in table XVII.10. A major share of total investment would be undertaken in the private sector (67 per cent) mostly in oil and gas and thermal generation, whereas the public sector would account for about 33 per cent of total energy investment, mostly in the hydropower sector.

Power. In the power sector, 49-56 per cent of the investments, or PRs 42-51 billion annually ($1-1.2 billion) are to be financed during the period 1998-2018 in the public sector by the two public sector enterprises, WAPDA and KESC, and the remaining investments will be undertaken by the private sector. KESC future investments will be limited to distribution. WAPDA investments include construction of ongoing thermal projects, future major hydroelectric projects, and transmission (including transmission requirements for new-generation capacity to be provided by the private sector) and distribution projects.

Oil and gas. In the oil and gas sector, the capital investment requirements for the infrastructure would cost a total of PRs 1,010-1,065 billion, which amounts to PRs 51-53 billion annually ($1.2-1.3 billion).

13 Ibid.

14 Ibid.

Table XVII.10 Investment of the energy sector

(Millions of rupees at 1992/93 prices)

Sector/fuel	*Low case (1998-2018)*	*High case (1998-2018)*
Exploration/development	500 886	501 223
Oil		
Refineries	87 396	87 585
Oil transport	172 449	203 407
Oil storage/distribution	137 103	137 245
Total oil	**396 949**	**428 237**
Gas		
Purification plants	943	946
Gas pipelines	91 075	102 195
Gas distribution	20 275	32 899
Total gas	**112 293**	**136 040**
Power		
Generation	366 727	364 630
Transmission	389 447	569 446
Distribution	86 046	85 186
Private power	632 145	1 052 351
Total power	**1 474 364**	**2 071 613**
Coal	88 421	88 421
Total energy sector	**2 572 912**	**3 225 532**

Source: Pakistan Energy Options Study, EW/WB 1995 (Draft).

4. Financial constraints/issues

General. As mentioned earlier, the investments required to expand the energy supply system in the wake of growing energy demand in the country are large. In the current situation where the public sector dominates the energy scene, the key issue is the financial sustainability of such an investment programme. This will ultimately depend on the level of tariffs, the ability to self-finance the investments, and the level of domestic and external borrowing required. As for the financing of private sector projects, the present financial system of Pakistan appears to be unable to support such a magnitude of investments. The recent experience in the Hub Power Project shows that long-term domestic financing in Pakistan is difficult to mobilize at present. The limited availability of local long-term financing is the real constraint on the mobilization of resources for private energy projects. Furthermore, given the lack of depth of the capital markets and the limited financial instruments available in the market place, competition for scarce domestic resources will be keen, both from the private sector, which will require financing for thermal plant construction, and other public sector enterprises.

Power. WAPDA and KESC will need to rely on their ability to mobilize resources on the strength of their own balance sheets. In the presence of the alarmingly high level of receivables and poor revenue collection, these utilities will face great difficulty in mobilizing resources from the market. Further affecting the creditworthiness of WAPDA/KESC is their dependence on the Government to seek approval for required tariff increases. Furthermore, the changing structure of WAPDA from a semi-autonomous public sector agency to that of a restructured, corporatized and partly privatized commercial enterprise will imply, among others, that WAPDA and the private sector would compete in the mobilization of local and external financial resources for their investment programmes.

Oil and gas. In this sector, a key issue to be addressed is whether the two utilities will be able to finance the domestic expansion of transmission facilities to deliver the additional domestic production and the imported natural gas to ultimate consumers. Internal cash generation is expected to finance 22 per cent of the investments (traditionally Sui Northern Gas Pipeline Limited (SNGPL) and Sui Southern Gas Corporation (SSGC) have financed from internal resources about 20 per cent of their investment programme). Based on the past borrowing experience and trading profile of both SNGPL and SSGC, the borrowing levels are expected to be achieved. In addition, both SNGPL and SSGC are in the process of being privatized and it is expected that the strategic foreign investors would make substantial investments in the companies. Similarly, Pakistan State Oil Limited (PSO), which shares a very large portion of the petroleum product infrastructure in the country, also faces a shortage of funds for future expansion in the wake of increasing demand.

5. Issues in pricing policy

The Government of Pakistan has been following the regulated price regime in the energy sector. Under this regime, energy prices are set by the Government from time to time which does not reflect the true economic cost of supply. In consequence, energy consumption has grown rapidly in recent years especially by those sectors/consumers which are subsidized. Currently, WAPDA neither utilizes cost-of-service analysis in tariff design nor effectively incorporates marginal cost techniques. As a result, there are large degrees of cross-subsidization, both inter-class and intra-class, and the costs that these subsidies impose on other customer classes are not transparent. Similarly, most of the producers prices reflect a cost-plus mechanism through which the producers are guaranteed a certain level of return over and above their costs, which leaves much to be desired as far as incentives for private producers are concerned.

6. Non-pricing policy issues

Although a policy for attracting private sector participation in the energy sector was introduced in the 1980s, the implementation of private energy projects has been limited by difficulties in the mobilization of external financing. Unlike in the power sector, government policies in the oil and gas sector have not been able to release the pressure on supplies by attracting the required investment. In addition, the lack of a transparent regulatory framework and overlapping of government responsibilities (policy, regulation and ownership functions) have been perceived by the private sector as excessive interference by the Government in the operation of the energy sector.

7. Environmental policy and conservation

Environmental policy,[15] with special reference to the energy sector, in Pakistan has not been so prominent up to now. Similarly, Pakistan's achievement in the field of energy efficiency and conservation has been mixed. According to the Constitution, both the environment and ecology are under the concurrent jurisdiction of the federal and provincial governments, both of which have legislative and executive powers in these areas. The 1983 Pakistan Environmental Protection Ordinance provides the legal framework for government policies. A National Conservation Strategy, approved by the Cabinet in 1992 as a basic document for environmental action, provides a set of policies aimed at conservation, sustainable development, and improved efficiency in managing natural resources. The main shortcoming has been the lack of action at the policy and legislative levels. In order to support the development of environmentally sustainable energy options, there is an urgent need to strengthen the environmental institutions.

8. Regional cooperation

As mentioned earlier, the advantage of regional cooperation in terms of a relatively cheaper supply of energy has already been recognized by the Government of Pakistan and the countries of the region. Serious efforts are under way to import gas from different alternatives on a cost-advantage basis from Qattar through a submerged coastal pipeline, an in-land gas pipeline from the Islamic Republic of Iran and over-land pipeline from Turkmenistan. Similarly, an oil pipeline from Turkmenistan to Karachi is also under active consideration by the Government of Pakistan. In the area of oil refining, two important projects are being seriously considered, the Iran-Pak Refinery and Pak-Arab Refinery. These refineries will be based on imported crude from the Islamic Republic of Iran and the Middle-East respectively and will have equity shareholding by the respective countries along with Pakistan. In the area of power transmission, the proposal of a transmission line from Tajikistan is also an available option. Serious pursuit of the above projects and other projects of a similar nature is likely to improve the situation in the energy infrastructure development of Pakistan in the future if the right kind of policies are pursued in this direction.

C. POLICY OPTIONS

Owing to financial constraints and inappropriate pricing policies in the past, severe energy supply constraints emerged in the early 1980s and have continued to this decade. These constraints have been a major impediment to the growth of the economy. Traditionally owned and operated by the public sector, the gas and power utilities have been constrained in the implementation of their investment programmes by inadequate public revenues and controlled pricing policies. In order to avoid a worse situation in the future in the wake of the future energy balance, the Government has already started taking steps towards consistent pricing policies, a privatization programme, a regulatory framework and environmental/ conservation policies.

1. Role of the private sector

In the 1994 energy policy, the Government adopted an aggressive strategy towards the privatization of the sector and increasing the efficiency of the demand and supply of energy. Under this programme, the two electricity utilities, WAPDA and KESC, will be corporatized and gradually privatized. The two gas public utilities, SNGPL and SSGC, as well as OGDC, the state-owned exploration company, will also be privatized. However, the Government and WAPDA should take a more proactive role in the implementation of the reorganization and privatization of the power sector. In particular, the Government should pursue more vigorously the establishment of a

[15] Government of Pakistan (1994b).

National Electrical Power Regulatory Authority (NEPRA), and WAPDA should accelerate the corporatization of its generation and distribution units. The Government should allow and also encourage other forms of sales of power, where possible at deregulated tariffs. This would accelerate the deregulation and privatization programme, while minimizing the level of government liabilities. Similar steps are needed in the oil and gas subsectors: privatization and corporatization of SNGPL/SSGCL and OGDC and respectively; and immediate establishment of a Gas Regulatory Authority (GRA) and a Petroleum Regulatory Board (PRB).

2. Reduced role of the Government

The Government had played its multi-faceted role in the energy sector looking after upstream/downstream activities, implementing policy measures, performing ownership responsibilities, appraising investment proposals, and setting prices and profits. Although the existing system provided strong central control, it resulted in a number of anomalies, which can be summarized as follows: (a) concurrent to policies attracting new investments, it has retained control over price and returns fixation; (b) policy implementation, ownership, and routine administrative responsibilities have given the wrong signals to the private sector to undertake new initiatives on a competitive basis; (c) very little competition in the petroleum sector markets has resulted in an inefficient allocation of resources; and (d) the absence of private sector participation has resulted in greater public sector involvement in new infrastructure investments, which, however, have lagged behind the requirements owing to financial constraints and inadequate implementation capability.

In the light of the above, and recognizing a need to further develop its domestic energy resources, enhance the efficiency of the energy sector and streamline the sector's institutions, the Government has already launched in the gas sector (a) restructuring programme of the gas industry by undertaking a restructuring and privatization programme for SNGPL and SSGC; (b) the Government intends to move the pricing formula from a cost-plus structure to a formula which rewards the company for efficiency gains. Similarly, in the power sector in 1992, the Government approved WAPDA's strategic plan which called for meeting three critical goals in the power sector: (i) to enhance capital formation; (ii) to improve efficiency and rationalize prices; and (iii) to move towards competition by providing a greater role for the private sector.

3. Role of regulator

Regulatory bodies are conceived to (a) oversee the privatization exercise, (b) regulate rates for service, (c) foster and preserve the competitive structure and (d) ensure the coordinated reliable and adequate supply of energy. The most important role that a regulator can immediately play in regulation is to focus on efficiency improvement by setting performance indicators for private/public companies and conduct periodic monitoring. With the introduction of the private sector and a more liberalized public sector in the future energy scene of Pakistan, it is necessary that an independent regulatory institutions should be in place. The Government has already taken steps towards the setting up of regulatory authorities. A critical element of the power sector strategic plan is the creation and establishment of a National Regularity Authority, which would be mandated to oversee the restructuring process, evaluation of the privatized power sector and would regulate monopolistic services. Similarly, the Government has planned to establish a Gas Regulatory Authority and a Petroleum Regulatory Board well before the corporatized and privatized energy sector takes shape.

4. Rational pricing policy

As recognized earlier, liberal pricing policies in the past have been pivotal in encouraging higher demand on the one hand, and failed to help develop an appropriate supply infrastructure system on the other. Starting in 1996, the Government introduced important energy price reforms to allow public sector enterprises to mobilize the required financial resources and to reduce the growth in energy consumption. To assist in this issue, and install greater confidence among potential investors, WAPDA has been given greater independence in the short period in determining electricity tariff increases. There is room for improvement in the pricing regimes of gas and petroleum products in such a way that the inherent imperfections in the existing prices are removed in both producer and consumer prices without favouring either of the two in particular.

5. Financial constraints

At present, the public sector is absorbing about 70 per cent of the capital available. By reducing the fiscal deficit to sustainable levels, the Government can free some resources for the private sector. To foster the development of the capital markets as a source of long-term debt and equity financing for private power projects, the new energy policy introduced important reforms. While the introduction of these reforms represents important progress towards the mobilization of local financing for power projects, some of the issues described above still need to be addressed. Further action is required to make the privatization programme in the energy sector successful.

D. CONCLUSIONS AND RECOMMENDATIONS

The analysis of energy infrastructure development reveals that excess demand and constraints supply have been the burning issues in Pakistan's energy sector in the past and still are, to an even greater extent. Two important factors, namely, overwhelming control by the Government in the energy sector and irrational energy pricing policies, have been singled out as the main reasons for this situation in energy infrastructure development. Energy pricing policies on one hand have encouraged higher energy demand owing to inherent cross-subsidies in the consumer tariff structure of electricity and gas, but on the other hand, the producers' pricing mechanism has failed to encourage sufficient development in the energy infrastructure to meet the growing demand. Similarly, the dominating role of the public sector in the ownership of energy infrastructure, which clashes with the Government's role of policy-making and price-setting, has also been one of the impediments to energy infrastructure development.

The above concerns have already been recognized by the Government and major changes are being made in the areas of both energy pricing policy and energy infrastructure development. Although the Government has undertaken the corporatization and privatization of public sector entities and is pursuing policies to encourage new investments in the energy infrastructure development, the following recommendations, which point towards more action and measures, may be considered.

Role of the Government. The Government should make a serious effort to monitor the implementation of the new energy policy and its effectiveness. It should, in particular, undertake the following action in the near future: (a) rationalize the energy prices towards the economic cost of supply; (b) accelerate the reorganization and privatization of the power sector; and (c) introduce a regulatory authority for gas and petroleum activities including the strengthening of the National Electrical Power Regulatory Authority (NEPRA).

Regulatory framework. It is essential that a regulator operate in an environment which is free of undue political influence. However, in order to make its operations more acceptable to the fuel and power industry and its customers, it is also essential that all of the regulator's rulings, decisions and processes should be open to the public at all times.

Petroleum policy. The Government should promote competition in the petroleum industry by (a) allowing new companies to enter the market without conditions, (b) deregulating distribution margins and transport fees for marketing companies, (c) liberalizing consumer prices, (d) rationalizing the structure of taxes on different products, and (e) introducing effective steps to reduce government intervention to the minimum.

Gas policy. The policy-making, regulatory and administrative functions at present exercised by the Government should be separated. A gas regulatory framework must be in place before the privatization of SNGPL and SSGC. Pricing reforms are also necessary to promote energy conservation, and to facilitate resource mobilization in the sector.

Power policy. In the power sector, the package of incentives provided to the private sector have succeeded in increasing the number of private thermal power generation plants in the power system. Similar efforts are needed in the areas of hydel and indigenous coal-based generation in the future to make use of domestic resources on the one hand, and to lessen the burden of imported fuel on balance of payments, on the other.

Capital market reforms. There is a need to identify particular issues in the financial sector regarding the mobilization of resources for projects with long gestation periods. Some of the main issues which stand out are particularly those related to the ability of financial institutions operating in the country and the domestic capital market to mobilize resources. In particular, the Government should facilitate the creation of a secondary market to encourage the mobilization of long-term savings and foreign capital in the domestic market.

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ANNEX

ENERGY INFRASTRUCTURE

Generation	**1985-1986**	**1995-1996**
❑ Total generation, WAPDA	5 023 MW	11 094 MW
❑ Hydel generation, WAPDA	2 898 MW	4 826 MW
❑ Thermal generation, KESC	1 138 MW	1 738 MW
❑ Private	–	1 292 MW
Transmission	**1985-1986**	**1995-1996**
❑ WAPDA and KESC	22 729 km	27 229 km
Distribution:	**1985-1986**	**1995-1996**
❑ WAPDA and KESC	206 975 km	268 486 km
❑ Grid stations (WAPDA)	31 508	12 400
Gas transmission and distribution		3 500 km

Refineries	**Current capacity**
❑ National Refinery Limited	3.0 (million tons/year)
❑ Pakistan Refinery Limited	3.0
❑ Attock Refinery Limited	1.6
Fuel transportation	**Current capacity**
❑ Pipelines	4.5 (million tons/year)
❑ Road	4.2
❑ Railway	2.6
Distribution	14.0 (million tons/year)
PSO	76 per cent
SHELL	18.5 per cent
CALTEX	5.4 per cent
Storage	**Current capacity**
Karachi Port	80 000 (Tons)
Port Qasim	30 000 (Tons)
Oil companies	467 846 (Tons)
Refineries	618 050 (Tons)
PARCO	203 769 (Tons)
Under construction	160 000 (Tons)

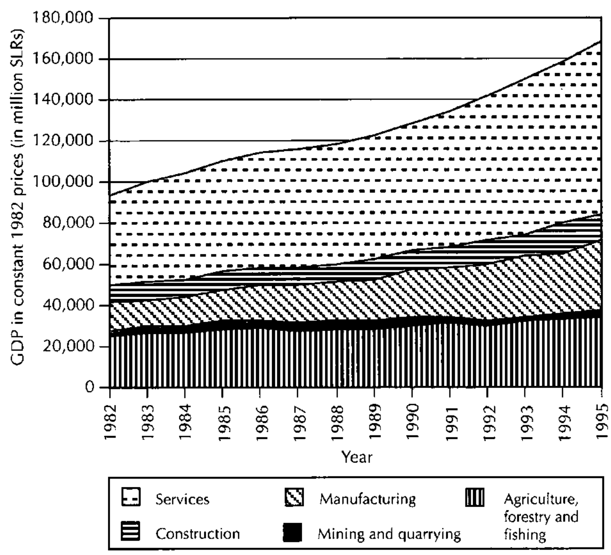
XVIII. INFRASTRUCTURE AND ENERGY PRICING POLICIES: SRI LANKA*

INTRODUCTION

Sri Lanka, an island south-east of the Indian subcontinent (situated between 6° and 10° north and longitude 80° and 82° east), has a population of approximately 18 million people and a land area of 65,600 square kilometres (maximum length and width 432 km and 224 km respectively). Its tropical weather is characterized by an average temperature of 26°C and average humidity of 80 per cent; the country receives close to 2,000 mm of rain annually, the bulk of which comes during two monsoon periods.

Sri Lanka's GDP in 1996 was SLRs 621,662 million at current factor cost prices (1 US dollar = SLRs 59.00 in 1996); over the past five years, Sri Lanka has maintained an average annual real economic growth of 5.5 per cent. The economy grew at a low 3.9 per cent during the period 1995/96. Agriculture, forestry and fishing now account for over a fifth of the country's GDP. These three sectors together employ the largest share of the labour force (39 per cent), followed by the services and hotel sectors (32 per cent). The industrial sector (manufacturing and construction) currently contributes 27 per cent to GDP; during the past decade the service sector has shown significant growth, signalling the increasing importance of service-related activities. Figure XVIII.1 shows the historical composition of GDP in Sri Lanka for the period 1982-1995.

Figure XVIII.1 Historical composition of GDP



Source: *Annual Report* (1982-1995) (Central Bank of Sri Lanka).

A. ECONOMIC POLICY OF THE GOVERNMENT

The *Economic Policy Statement* of the Government of Sri Lanka issued in September 1994 confirms the Government's continued commitment to building a strong economy within the market framework, as evident from the following extract:

> Public investment would be needed to build the infrastructure that is required as a necessary complement to rapid private sector growth. However, as the resource requirements for the provision of adequate infrastructure are so overwhelmingly large, a significant portion of the infrastructure investment efforts will have to be undertaken by the private sector. This would be expected to complement public sector infrastructure expenditure in areas such as roads and highways, power, telecommunications and ports. Private sector infrastructure investment would occur under arrangements such as build, operate and transfer (BOT) and build, operate and own (BOO), which would be implemented within an evaluation and regulatory framework that would guarantee transparency and accountability.

The above statement is very clear on the Government's intention regarding private sector participation in infrastructure development, that includes programmes related to power (and energy). The scope of the private sector would be expanded by encouraging and providing the necessary facilities, including a legal framework within which it can enter into new areas of production in agriculture, industry, infrastructure development and the service sectors. As clearly stated in the policy statement, the private sector is expected to play a key role in energy sector development activities; the role of the private sector will add a new dimension to energy sector planning and policy formulation.

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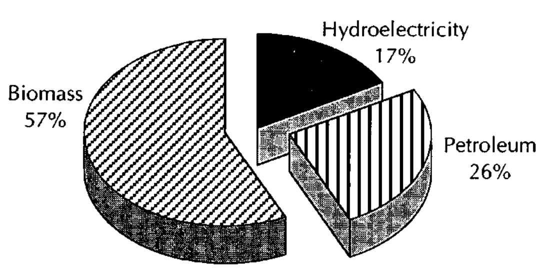
B. ENERGY SECTOR OVERVIEW

Sri Lanka's economy underwent a fundamental change in the post-1977 period with its transformation from essentially a centrally planned economy to a market-based one. Immediately following this change, the demand for energy services, electricity and petroleum in particular, recorded unprecedented growth.[1]

Sri Lanka is a country with moderate energy resources of its own. With no proven reserves of fossil fuels, hydro energy and biomass (mainly fuelwood) are Sri Lanka's only indigenous energy resources. All of the country's fossil fuel needs are imported – mainly as crude oil and partly as finished petroleum products. As is typical of any developing country, the household sector is the largest consumer of final energy, accounting for nearly 70 per cent of the total energy consumed in the country. About 90 per cent of the household energy is still provided by fuelwood and other biomass fuels. Petroleum products and hydroelectricity are the other two main sources of primary energy in the country, accounting for approximately 26 and 17 per cent of the total energy supply in 1995. Figure XVIII.2 depicts the energy supply by source for 1995.

Figure XVIII.2 Energy supply mix in 1995



Source: *Energy Balance 1995*, Energy Conservation Fund.

Meeting the growing demand for energy is a major challenge faced by any developing nation such as Sri Lanka. Fluctuations in world oil prices, intentions of cushioning transport and kerosene (lighting) costs, and the Government's need to generate adequate tax revenues have led to a complex system of energy prices that incorporate numerous levies, taxes and severe distortions. The sale prices generally do not reflect production costs or world market prices, as is evident from those of petrol, diesel and kerosene.

Sri Lanka's only indigenous "commercial" energy resource, hydroelectricity, has only a limited further development potential of about 4,000 GWh per year (approximately 1,000 MW in capacity). Funding electricity sector expansion is a major challenge faced by many developing countries such as Sri Lanka. As shown in figure XVIII.3, Sri Lanka's total power sector investment requirements for the next two decades are estimated at around $2.5 billion. Developing countries have traditionally depended on loans from foreign donors for their electricity sector capacity expansion programmes in the past. Such funding has seen a marked decline recently as a result of a shift in focus on the part of many international donors. In power sector development, the long gestation periods associated with capacity-building (e.g. 5 to 10 years for installing hydropower plants) call for decision-making well in advance, even under the uncertainties pertaining to demand growth. In the short and medium terms, the projected GDP growth rates of 6-6.5 per cent a year will give rise to a steady increase in the demand for energy. Electricity consumption, in particular, is expected to grow at around 9 per cent a year for the next decade. Meeting the demand certainly needs a concerted and urgent effort in establishing new generating, transmitting and distributing facilities.

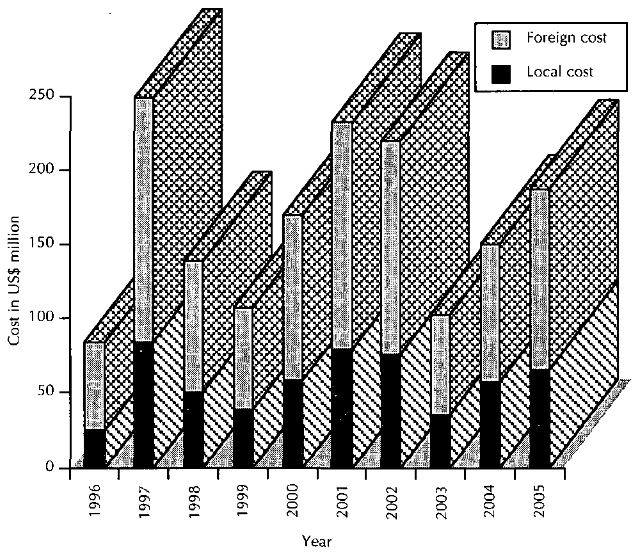
The other major "commercial" energy source used mainly in transport, industry and power generation is oil, which is wholly imported, either as crude oil or finished products. The petroleum bill of the country accounts for about SLRs 20 billion annually, which translates into nearly 11 per cent of total imports or 14 per cent of the country's export earnings.[2] The oil import requirements have been increasing over the years; this trend is likely to continue, with more thermal electricity generation added to the system.

The main "non-commercial" energy source is biomass, which includes fuelwood. Biomass fuel availability and consumption need to be viewed in the context of the diminishing forest cover of the country. In 1956, the total forest cover of Sri Lanka had been estimated at 44 per cent of total land area; this figure had reduced to 27 per cent in 1981 and 23.9 per cent in 1994. As fuelwood is transported and sold to households and industry, it can no longer be classified as a "non-commercial" source of energy in the context of Sri Lanka. In accordance with tradition, however,

[1] The electricity growth rate had averaged around 6.6 per cent for the period 1978-1995. GDP had grown at an average rate of 4.4 per cent a year during the same period.

[2] These percentages, however, depend on the import price of oil and the quantity of imports to satisfy the demand.

Figure XVIII.3 Power sector investment requirements up to 2005



Source: Long-term generation expansion planning studies: 1996-2010, Planning Division, Ceylon Electricity Board.

the definition "commercial" used in this paper excludes biomass.[3]

Although the concerns outlined above are present, increasing energy supplies of the appropriate types are required to support the social and economic growth of the country. Long gestation periods (5 to 10 years in certain instances) for completing major energy projects warrant decision-making well in advance, though facing uncertainties in respect of demand growth and many other future parameters.

In the above context, what is the role and the optimum mix of traditional energies for the future? Will non-traditional as well as new and renewable sources of energy have a place? If so, to what extent? What is the scope for energy conservation? What are the possibilities of demand modification, source-switching and demand-matching? A variety of similar questions need examination.

In the short and medium terms, the projected annual GDP growth rate of about 6.0-7.5 per cent will give rise to a steady energy demand increase. For instance, in the electrical power sector, the annual growth rate is expected to be in the region of 9 per cent. Meeting such demand will need a concerted and urgent effort for new installations for generation, transmission and distribution facilities.

C. MAIN ASPECTS COVERED

- Energy usage patterns of Sri Lanka from different sources
- Projection of likely energy demand for different categories of consumers and types of energy, considering the scope for beneficial energy substitutes
- Rural energy demand and supply methods and applications relevant to Sri Lanka for energy end-use efficiency improvement (demand-side management) and energy conservation
- The extent of indigenous energy sources that are available as well as those which may be developed and shown to be economically viable
- Optimum investment basis for supplying energy sources in an environmentally acceptable manner
- Financing strategy and role of the private sector; private power development
- Present pricing of energy and directions for change
- Directions for research and development in energy supply and end-use technologies
- Regional cooperation

D. ENERGY SUPPLY AND DEMAND

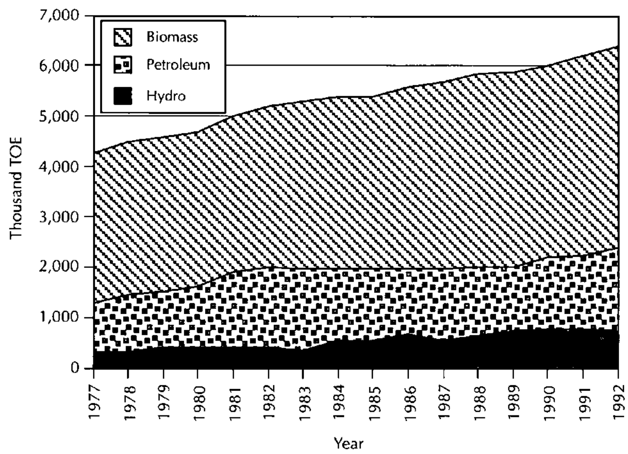
Sri Lanka's limited indigenous energy resources, mainly biomass and hydroelectricity, accounted for about 75 per cent of the primary energy supply in 1994. The country's hydroelectric potential is estimated to be in the region of 2,000 MW; 1,040 MW of this has already been developed.

Sri Lanka has no known fossil fuel resources; imported petroleum, which currently accounts for a fourth of primary energy supply, will continue to play an increasing role in the energy sector.[4] Figure XVIII.4 depicts the historical energy supply pattern in the

[3] Biomass is collected only in the rural areas.

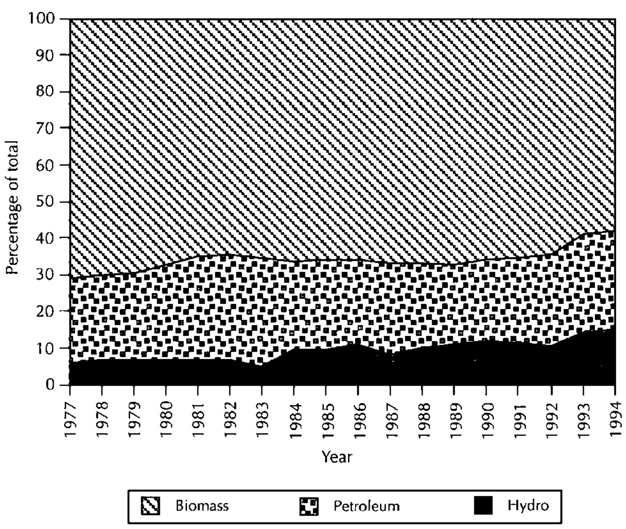
[4] Although a modest petroleum exploration programme was carried out, the prospects for making substantial oil discoveries are believed to be limited. A small quantity of peat had been located in the marshy lands located north of Colombo; a recent feasibility study indicated, however, that the quantity and extent of this reserve could not prove to be commercially viable for extraction and use in power generation.

Figure XVIII.4 Primary energy supply by source, 1977-1992



Source: *Sri Lanka Energy Balance,* Planning Division, Ceylon Electricity Board.

Figure XVIII.5 Share of primary energy supply by source, 1977-1992



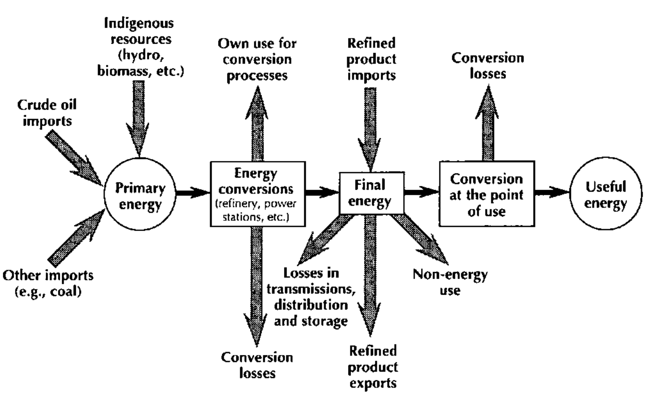
Source: *Sri Lanka Energy Balance,* Planning Division, Ceylon Electricity Board.

country. This presents a rather skewed picture of the supply side with regard to biomass resources; the estimates available at present indicate that the annual availability of biomass, fuelwood in particular, has been substantially higher than the actual amounts consumed in a given year.

Although reliable data on biomass supply are difficult to obtain, estimates clearly indicate the important role of biomass fuels in the gross energy supply.[5] As shown in figure XVIII.5, the share of biomass in the primary energy supply has remained high; its contribution to the total useful energy, however, is much less due to the relatively low efficiency of conversion of biomass, particularly in domestic cooking, for which a major part of biomass is used. Biomass fuels are likely to remain an important source of energy. Other renewable resources, such as solar, wind and small-scale hydropower, offer prospects for exploitation even though their contribution is likely to remain marginal in the next decade.

The flow of energy in an economy may be measured at three levels: primary energy, final energy and useful energy. As shown in figure XVIII.6, primary energy comprises all energy directly used in various economic activities, as well as by the transforming industries such as refinery and electric power plants. Final energy is the energy that is directly used for economic activities, including energy supplied by transforming industries. Clearly, the difference between primary and final energy is the energy lost in transformation. Useful energy is the energy that produces work (heat, light, motive power) after conversion by end-use equipment (stoves, light bulbs, electric motors). In the case of biomass (including fuelwood), while the primary energy "supply" is as indicated in the figure, the energy "availability" (taking into consideration utilized biomass which decays all over the country) bears a much higher proportion.

Figure XVIII.6 Energy flow diagram for Sri Lanka



E. ENERGY SUPPLY

1. Petroleum

The state-owned agency, Ceylon Petroleum Corporation (CPC), is responsible for all aspects of petroleum supply except the import and retail marketing of LPG, which is now handled by the private monopoly Shell (Lanka) Limited.

5 The share of biomass in the total energy supply was approximately 61 per cent in 1994.

The bulk of the country's petroleum requirements is imported as crude oil, which is then processed at the 51,000 barrels/stream day oil refinery at Sapugaskanda. The crude slate comprises Middle East crude, whose average gravity is in the 32-34 degree API range, and some Far Eastern crude, such as *Miri* and *Tapis* blends having higher percentages of middle distillates. CPC acquires most of its crude oil requirements through contracts with the government oil companies of Egypt, the Islamic Republic of Iran, Malaysia, Saudi Arabia and United Arab Emirates, while the balance is bought in the spot market.

While the refinery's aggregate throughput is greater than the total consumption of petroleum products in the country, its production slate differs today less significantly from the mix of products demanded. Processing as much crude oil as possible to meet the demand for middle distillates (kerosene, jet A-1 and diesel) has still resulted in a deficit of these products, requiring supplementary imports, while at the same time producing a marginal surplus of naphtha, which has to be exported. The refinery is operated at the optimum level to minimize net foreign exchange outflow, governed by three factors: crude oil prices, demand pattern and border prices of finished products.

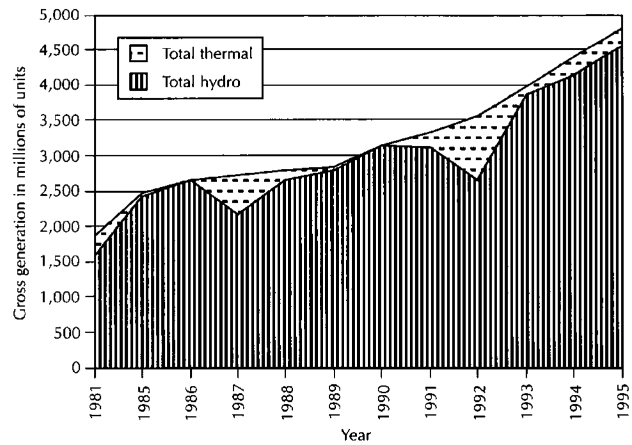
2. Electricity

Since 1992, the total installed electricity generating capacity has remained unchanged at 1,409 MW (comprising 1,137 MW of hydro and 272 MW of thermal). As shown in figure XVIII.7, the total electrical energy consumption has registered significant growth. The large share of hydropower in the total electricity generation depicted in figure XVIII.7 is likely to diminish by the turn of the century as most planned future generating plants are thermal-based. Figure XVIII.8 represents the generation pattern expected under the long-term generation expansion plan of Ceylon Electricity Board.

3. Biomass

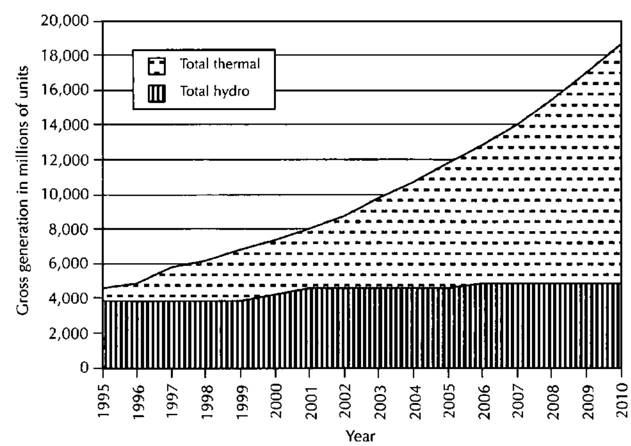
Existing estimates should be viewed with some caution, as the absence of reliable data on biomass makes it difficult to identify the pattern in total energy demand and correlate it to economic variables. The data available point to some increase in the consumption of biomass fuels in response to increasing oil prices (e.g. furnace oil in tea factories being replaced by fuelwood). During recent decades, natural forests have been disappearing rapidly, with an adverse

Figure XVIII.7 Historical growth in electricity generation



Source: *Monthly Review Report,* System Control Branch, Ceylon Electricity Board.

Figure XVIII.8 Expected future generation mix



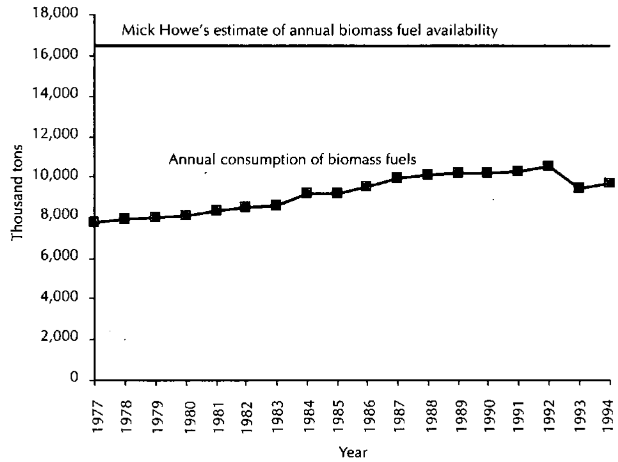
Source: Long-term Generation Expansion Planning Studies 1995-2009, Planning Division, Ceylon Electricity Board.

effect on the sustainability of future fuelwood supplies. In localities in which the forest has been depleted, the result is adverse environmental impact. The Forestry Sector Master Plan Project studies concluded in 1995 indicated that no serious crisis was likely to emerge in the future. This conclusion is compatible with the estimate that on a national basis annual biomass availability far exceeds its annual consumption (there can be localized shortages of fuelwood unless an intervention is made by the Government). A comparison between all-island availability and consumption is given in figure XVIII.9.

F. ENERGY-ECONOMY RELATIONSHIP

The increasing energy consumption has been linked historically to economic growth and population

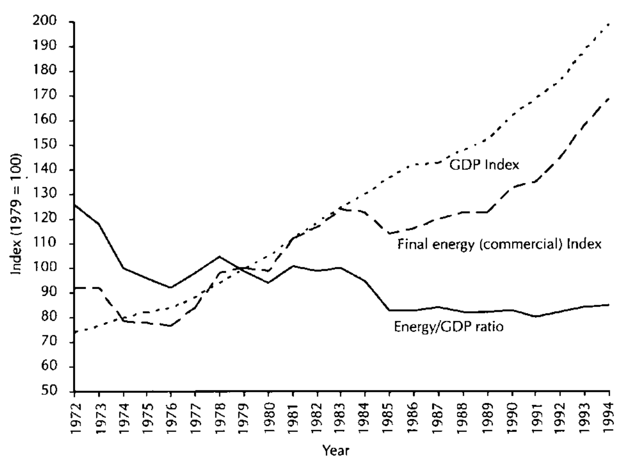
Figure XVIII.9 Potential biomass fuel production



Source: Mick Howe, *Farmers, Forests, and Fuels* (1990).

growth. Several important policy changes beginning in the late 1970s had a significant influence on energy consumption, in both the level and the pattern. Table XVIII.1 gives some key growth indices for different periods in the last three decades. With the liberalization of the economy in the late 1970s, the demand for energy has increased substantially, particularly in the industrial and transport sectors. The trends in GDP and final energy consumption from 1972, excluding biomass fuels, are shown in figure XVIII.9. The decline in final energy consumption following the first oil crisis in 1973 was mainly due to the lower demand for petroleum products. The increase in the growth rate of energy consumption during the intermediate period 1977-1982 was of the order of 6.0 per cent a year corresponding to an yearly GDP growth rate of 6.8 per cent. From 1982 to 1989, the annual energy consumption growth rate had declined to 1.3 per cent while the GDP growth rate had dropped to 3.7 per cent, mainly due to the political instability in the country. The energy intensity of GDP also had shown a drop from 1972 up to 1985, remained static during the period 1985 to 1992 and increased thereafter. This reduction in energy intensity can be partly attributed to structural adjustments in the economy as well as energy efficiency improvements and fuel substitutions brought on by the first oil price shock in 1973. It may also be misleading, because energy from biomass (classified as "non-commercial")[6] is not accounted for in the above analysis, though more and more biomass replaced oil between 1972 and 1995.

Figure XVIII.10 Relationship between final energy (commercial) and GDP



Source: *Energy Balance,* Planning Division, Ceylon Electricity Board *Annual Report,* Central Bank of Sri Lanka.

[6] Commercial energy here excludes biomass energy.

Table XVIII.1 Growth rates of GDP, final energy demand and energy prices from 1970 to 1994
(petroleum products and electricity)

Period	*Percentage growth rates*					
	1970-1973	*1973-1977*	*1977-1980*	*1980-1982*	*1982-1989*	*1989-1994*
GDP	2.20	3.30	6.80	5.50	3.70	5.50
Total energy demand	–	-2.50	6.00	6.00	1.30	7.10
Electricity	7.60	4.70	10.20	10.10	4.90	8.70
Petroleum products	-0.30	-3.10	5.50	5.50	0.80	6.80
Energy intensity in GDP (energy/GDP)			0.88	1.09	.98	1.29
Change in energy prices						
Electricity	-1.50	-3.60	31.10	38.30	-6.50	1.80
Petroleum products	11.20	14.20*	30.00	-3.00	-2.50	-3.20

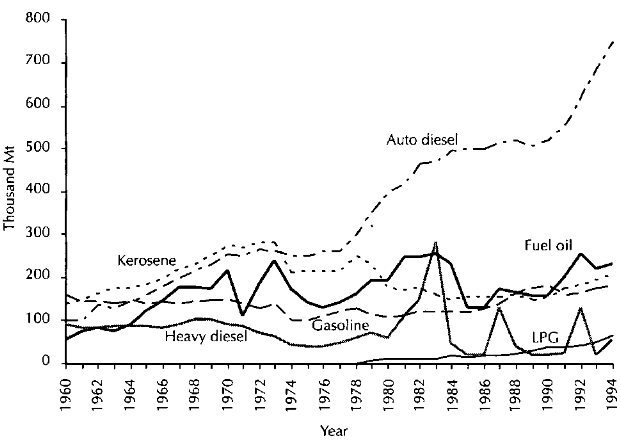
Source: *Statistical Data,* Ceylon Petroleum Corporation *Annual Report,* Central Bank of Sri Lanka.

G. ENERGY DEMAND

1. Petroleum products

The historical demand for petroleum products in Sri Lanka is shown in figure XVIII.11. From 1972 to 1997, the consumption of all petroleum products, except that of LPG and auto diesel, showed a decline. This resulted from the virtual elimination of petroleum-based electricity generation following the addition of new hydroelectricity capacity, coupled with the reduction in demand caused by the trebling of prices. Since 1977, most petroleum products have shown an increased demand, especially auto diesel and LPG. The demand for heavy diesel and fuel oil showed a marked increase in 1982 and 1983, resulting from the increased thermal electricity generation in those two years.

Figure XVIII.11 Demand for petroleum products

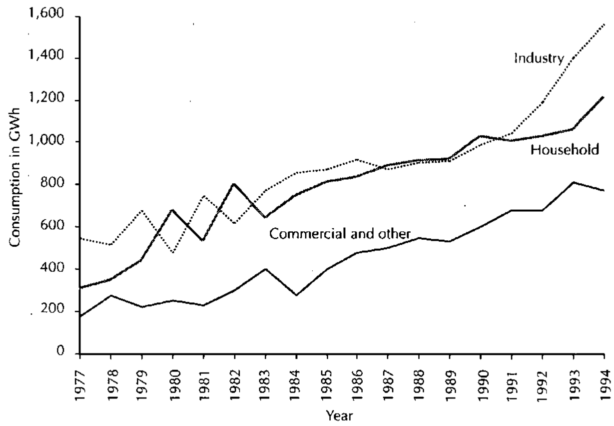


Source: *Statistical Data,* Ceylon Petroleum Corporation.

2. Electricity

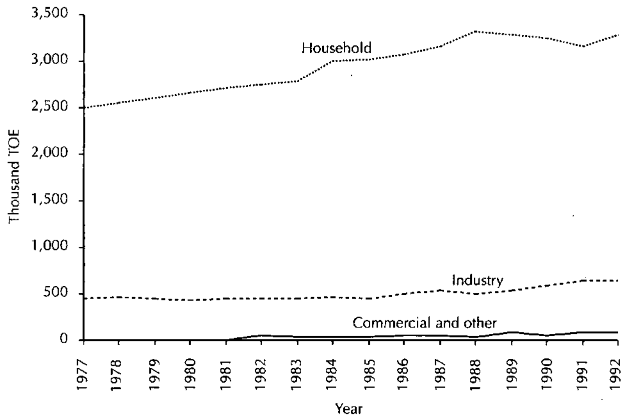
In contrast to the demand for oil, electricity demand continued to grow at an average annual rate of 4.7 per cent during the period 1972-1977 and 10 per cent per annum in the early 1980s. Between 1982 and 1989, the growth rate dropped to 4.9 per cent and increased again to 8.9 per cent from 1989 to 1994. To date, less than 45 per cent of the households are provided with grid electricity. This implies that the consumption of electricity in the domestic sector is constrained partly by inadequate lines and partly by the inability to afford to pay for electricity.

Figure XVIII.12 Electricity demand by sector



Source: Energy balance, Planning Division, Ceylon Electricity Board.

Figure XVIII.13 Biomass fuel demand by sector



3. Biomass

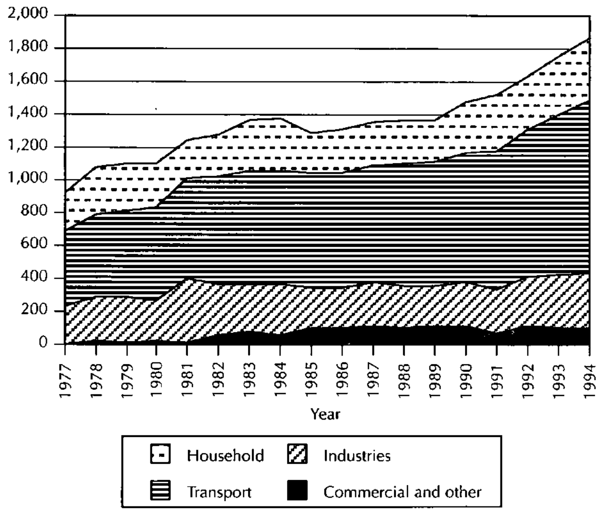
The absence of reliable data on biomass makes it difficult to identify the pattern in total energy demand and to correlate it to economic variables. Figure XVIII.13 shows the trends in biomass fuel use, based on estimates available. Approximately 14 per cent of the biomass used is for industrial and commercial purposes.

4. Sectoral energy consumption

(a) Industry

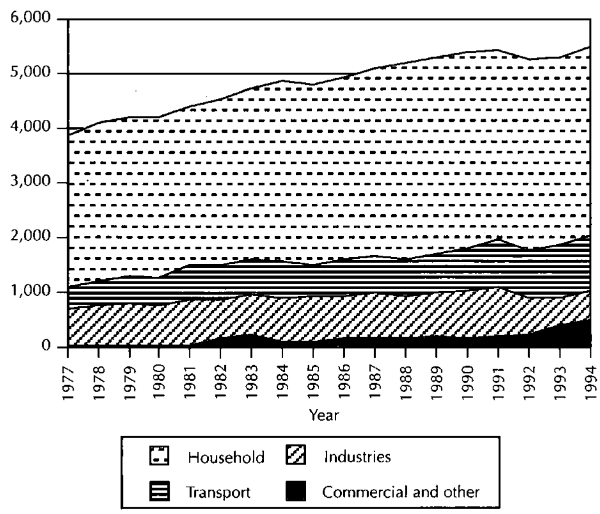
The industrial sector accounted for 17.8 per cent of the total electricity and petroleum products consumed in 1994; during the same period, the share of biomass fuels consumed by the industry decreased to 8.4 per cent. The manufacturing subsector, which contributes the largest share of the industrial sector's

Figure XVIII.14 Final energy (electricity and petroleum) consumption



Source: Energy Balance, Planning Division, Ceylon Electricity Board.

Figure XVIII.15 Final energy (total) consumption



Source: Energy Balance, Planning Division, Ceylon Electricity Board.

value added, consumes almost all of the sector's energy; mining operations consume relatively small amounts of energy. The consumption of commercial energy in the manufacturing sector rose at an average annual rate of 8.8 per cent during the period 1982-1994 from 306.5 kTOE in 1982 to 330.8 kTOE in 1994). This is mainly due to the expansion of textile and leather product manufacturing and non-metallic mineral production. The main sources of energy in the manufacturing sector are electricity, fuel oil, heavy diesel, and biomass. Other fuels, such as LPG and kerosene, are consumed in small quantities and reliable data on their usage are not readily available. A major petroleum product consumer, the State Fertilizer Manufacturing plant operated during the period 1982-1984.

Energy-consuming activities in the industrial sector are categorized into three major areas: motive power, thermal energy and lighting. Electricity is used for motive power and lighting in all industries. Based on the results of the energy audits carried out, it has been estimated that on average 15 per cent of the total electricity is used for lighting. The balance 85 per cent is used in motor drives. Demand for thermal energy is supplied by fuel oil, heavy diesel and biomass fuels.

(b) Transport

At present, the transport sector in Sri Lanka depends entirely on petroleum products (gasoline and diesel) for its energy needs; it accounted for over 75 per cent of total petroleum consumption in 1994, compared with 50 per cent in 1977. Diesel is the dominant transport fuel, which is a reflection both of the relatively extensive public transport network and of the long-standing policy to price auto diesel well

Table XVIII.2 Estimated industrial energy consumption pattern by source in 1994

(Thousands of TOE)

Subsector	*Electricity*	*Fuel oil*	*Heavy diesel*	*Fuelwood*	*Bagasse*
Food, beverage and tobacco	23.8	19.7	8.8	409.7	151.0
Textile and leather products	28.8	27.2	4.6		
Wood and wood products	1.8	2.2	0.2		
Paper and paper products	4.2	10.5	0.7		
Chemical, petroleum, rubber, plastic	5.2	36.5	1.9	25.0	
Non-metal and mineral	15.3	46.1	4.0	145.7	
Basic metal products	1.7	4.2	0.1		
Fabricated metal, machinery	2.6	3.1	0.4		
Others	1.7	–	–		
Total	**85.1**	**149.6**	**20.8**	**580.3**	**151.0**

below gasoline. Since the liberalization of import regulations for private automobiles, a number of consumers have taken advantage of this relative price differential by importing diesel vehicles. As a result, the proportion of diesel vehicles has shown significant growth in the last decade, requiring the import of refined diesel fuel, over and above the refining capacity.

The consumption of gasoline, which is used mainly in private cars, has continued to fall until 1975 and started to grow at 4.4 per cent a year until 1990 to reach its 1960 level of consumption in 1975.[7] From 1990, consumption fluctuated to reach the 1990 level again in 1994. This fluctuation in gasoline demand was a reflection of frequent increases in price.[8]

(c) Households

While the per capita consumption of energy in Sri Lanka is low by international standards and most households use energy only for cooking and lighting, households account for more than 65 per cent of final energy consumption. This high proportion of household energy consumption can be attributed to the relatively low conversion efficiency of biomass, which is the predominant household fuel for most of the population, in domestic cooking.

Household energy will continue to grow rapidly as a result of the growing population and rising living standards. Only about 45 per cent of the households have access to grid electricity and the consumption of kerosene, used primarily for lighting, has been declining over the past two decades in response to higher prices and fuel substitutions for cooking. While LPG, which is mainly used for cooking in households, registered an annual average growth rate of 18.4 per cent from 1984 to 1994, kerosene increased only 3.3 per cent during the same period. Household electricity demand grew at an annual average rate of 7.2 per cent during the period 1984-1994.

[7] This level has been the highest for the past three decades.

[8] Gasoline consumption appears to be more sensitive to price changes in the short run.

Figure XVIII.16 Final energy consumption (electricity and petroleum) projection

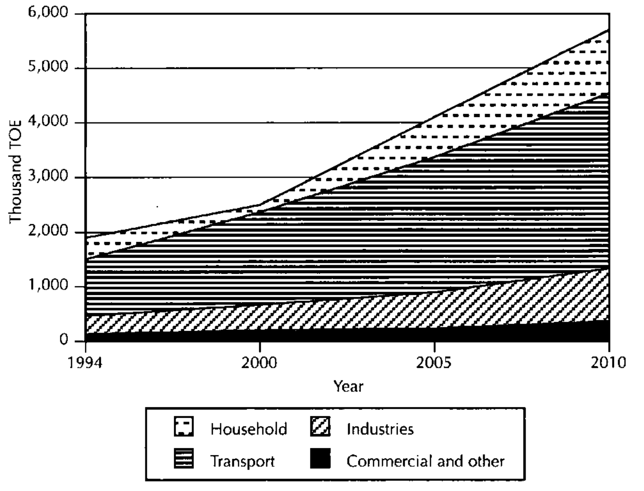
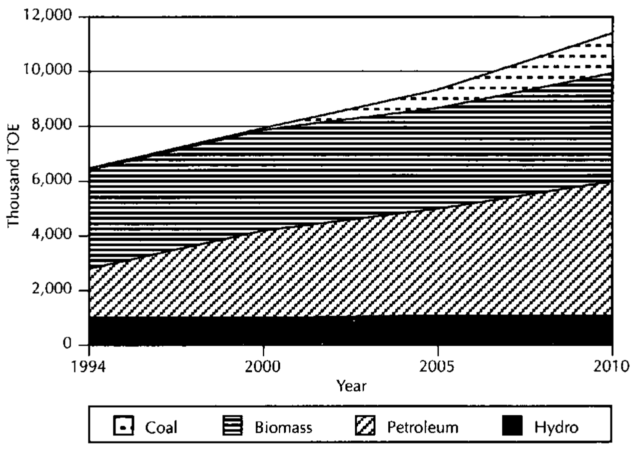


Figure XVIII.17 Supply projections by source (all energy)



H. SUPPLY-DEMAND PROJECTIONS

1. Petroleum

The rapid growth in the direct demand for petroleum products since 1994 is expected to continue at about 7.4 per cent up to 2000; this growth will slow down marginally after 2000 and reach about 7 per cent by 2010. However, because of the rapid increase in thermal power generation, total consumption of

Table XVIII.3 Petroleum demand projections (base case)

(kTOE)

	1990	*1994*	*2000*	*2005*	*2010*
Direct Consumption	1 150	1 494	2 290	3 151	4 409
Power Sector Consumption	44	658	529	493	
Total Consumption	**1 150**	**1 538**	**2 948**	**3 680**	**4 902**

petroleum products will rise at an unprecedented rate of 11.1 per cent up to 2000 and thereafter drop to a moderate level of about 5.2 per cent, mainly owing to expected thermal power generation switching to coal from 2002 and beyond, according to current planning.

The power sector's requirements for diesel and fuel oil dominate the growth pattern up to 2000 and increase the already high share of these fuels in total consumption. LPG consumption is expected to grow at a high rate during the next decade.

To evaluate the effect of this projected demand pattern on the operation of the CPC refinery, a number of additional assumptions have to be made regarding the projected level of bunker sales, forecast of international oil prices etc. The present analyses were conducted under the assumption that CPC will continue its policy of running the refinery to minimize net foreign exchange outflow. The refinery's crude throughput gradually increased from 1.95 million tons in 1995 to the maximum safe operating capacity of 2.2 million tons in 1998 and beyond.

The mismatch that existed between supply and local demand has been greatly reduced by the recent revamps carried out to the refinery plant and the increase in demand for fuel oil, which had enabled the exportable surpluses to be reduced and bring refinery output to match demand, with the exception of surplus naphtha, and continued the increase in the deficit of auto diesel. If the present naphtha-based combined cycle power plants become a reality, then the surplus may be turned to a deficit requiring naphtha imports. As it is not planned to increase the total refining capacity, CPC will have to increase imports of refined products to meet the increase in demand for all products. Based on these assumptions, the analysis shown at table XVIII.6 highlights the dramatic increase required in product imports owing to the limitations of the refining capacity. The demand for middle distillates exceeds the refinery's capacity to produce them and will be met through a growing volume of direct imports. At the same time the refinery is unable to meet the residual or bunker demand for fuel oil owing to the heavy demand for power generation and will consequently have to import fuel oil to continue the CPC foreign bunker operation. The total volume of refined product trade will more than triple during the next decade, which highlights the need to carry out further studies for assessing the potential benefits from modifying the refinery, increasing the crude oil processing capacity and matching demand for products by process modification. As an alternative to matching demand for products through process modification,

Table XVIII.4 Pattern of future petroleum product demand

	Actual	*Projections*			*Annual average growth rate*	
	1994	*2000*	*2005*	*2010*	*1994-2000*	*2000-2010*
LPG	64	138	203	298	13.7	8.0
Gasoline	184	276	387	543	7.0	7.0
Kerosene	208	286	332	384	5.5	3.0
Jet A-1	78	105	134	171	5.0	5.0
Diesel	804	1 567	2 052	2 916	11.8	6.0
Fuel oil	232	576	576	591	16.4	–
Total	**1 570**	**2 948**	**3 680**	**4 902**	**11.1**	**5.2**

Table XVIII.5 Petroleum import-export projections for the base case

(Thousands of metric tons)

	Actual		*Projections*		
	1990	*1994*	*2000*	*2005*	*2010*
Petroleum imports	125	295	1 310	2 333	3 540
Crude oil imports	1 758	1 999	2 200	2 200	2 200
Product imports as a percentage of crude imports	7.1	14.8	59.0	106.0	160.9

Table XVIII.6 Energy trade imbalance (base case) in constant millions of US dollars

	Actual		*Projections*		
	1990	*1994*	*2000*	*2005*	*2010*
Crude oil imports	310	236	294	294	294
Product imports	29	63	232	419	541
Product exports	100	75	74	110	118
Net oil imports	239	224	455	603	717

the demand for products can be modified by changing the price of products in the correct direction. The present price of petrol is relatively too high in relation to diesel and kerosene prices when compared with the international market or process costs. The increased import/export volume of refined products will also adversely affect the smooth operation of CPC's other installations and detailed studies are needed so that remedial action can be taken in time.

Apart from the refinery imbalance problem, another very important concern which emerges from analysis shown in figure XVIII.17 is that the future petroleum demand is growing, resulting in very rapid petroleum import requirements. However, in 1994, the cost of net petroleum imports dropped to $224 million and accounted for 7.2 per cent of export earnings compared with 12.1 per cent in 1990, owing to the adverse impacts of the increased consumption on the oil bill being mitigated to a greater extent by the fall in crude oil prices (from an average price of $23.50/barrel in 1990 to $16.30/barrel in 1994). Nevertheless, by the end of this decade, owing to increased quantities, the petroleum import bill will have registered more than 100 per cent increase to $455 million in constant prices, at an assumed constant crude oil price of $17.00/barrel. In rupee terms, the increases could be even more dramatic. This figure too will double by 2005.

I. ENERGY PRICING

1. General tariff principles

The general tariff principles which should be observed in formulating new retail tariffs for Sri Lanka are briefly outlined below. Some of the issues, in particular the question of "average costs" versus "marginal costs", are discussed in more detail later in this paper.

Cost-based tariffs

One of the fundamental principles of pricing calls for cost-based tariffs, i.e. the price of an electricity supply (at a particular voltage level and for a particular class of consumers) should reasonably reflect the cost of providing this supply, taking account of the load characteristics of the consumer.

The traditional approach to electricity tariffs uses the "average cost" of supply as a basis for pricing. The average cost is the total average annual cost of the electricity supply system (e.g. in terms of SLRs/kWh), including the historic costs of all existing installations. The average cost can be derived directly from the undertaking's annual expenditure statements, and it is therefore also referred to as the "accounting cost". The establishment of the cost of supply (and thus electricity price) at the different voltage levels based on the average cost is straightforward and relatively simple, provided sufficiently detailed accounts are available. The average cost approach also guarantees that the overall revenue equals the total annual costs, including the required margin of surplus.

However, from an economic point of view and in line with general pricing theory, the tariff structure should in principle reflect the long-run "marginal cost" (LRMC) or "incremental cost" of supply rather than the "average cost". The "marginal cost" of electricity is the extra cost of meeting an increment of particular consumer demand at a particular voltage level and time. According to this concept, it is the marginal cost-based tariff which provides more correct price signals and incentives to the consumer to use electricity efficiently, and thus leads to economic resource allocation in general.

A strictly marginal cost approach would theoretically require pricing each consumer individually, involving complex and expensive metering arrangements. In practice, in order to obtain a reasonably simple tariff and metering system (see other tariff principles stipulated below), a considerable amount of aggregation of consumer classes and averaging of costs is always necessary, thus requiring departure from marginal costing. Furthermore, tariff levels will in the end have to be adjusted to meet overall revenue requirements in accordance with the financial targets of the undertaking (and in line with total accounting costs).

The practical result of the tariff-making process is thus in the end usually a tariff system which is a compromise between the traditional "average cost approach" (accounting approach) and the economist's marginal cost approach.

In the present study it is proposed to determine both the "average cost" and the "marginal cost" of electricity supply at different voltage levels and for each consumer group. Both cost concepts will then be considered in designing the final tariff structure and rates.

Strictly cost-based tariffs (whether based on average or on marginal costs) will also often be in conflict with social and ecological considerations, if social costs are not properly taken into account. While a purely cost-based tariff system will thus not be practicable, the review of the present retail tariffs of CEB and Lanka Electric Company (LECO) indicates, on the other hand, that today's tariffs are considerably out of line with actual average (and future incremental) costs of supply. Existing cross-subsidies between certain consumer groups are quite substantial, as demonstrated in this paper.

One of the main objectives of the tariff revision will thus be to clearly identify existing cross-subsidies and to bring tariffs closer into line with cost-based prices. As noted and further out-lined below, social considerations must thereby be duly taken into account.

Consideration of overall revenue requirements

Overall, the tariffs must generate sufficient revenue – beyond covering operating expenditure – for building up adequate internal sources to support the utility's long-range power development, in addition to servicing debt and meeting all other financial obligations.

Minimum financial performance criteria are generally set in terms of rate of return, self-financing rate, debt service coverage and debt to equity ratio (see also sect. 10 (b) below).

Price differentiation between consumer groups on social or economic grounds

Strictly cost-based pricing, as already noted, would stipulate that electricity tariffs treat every consumer on an equitable basis (non-preference between consumer groups) regardless of the ability to pay for the electricity service or the importance of electricity for maintaining livelihood, or – in the case of industrial consumers – regardless of the importance of energy as a production factor. In practice, such strict ruling would be rather difficult to follow, and in many tariff systems today, some degree of cross-subsidy between consumer categories is retained on social or economic grounds.

Examples of this policy are:

The charging of lower rates for the domestic group (or at least the small – and generally lower-income – domestic consumer), for whom electricity is an important factor in the standard of living, as opposed to the commercial consumer, for whom electricity costs are often marginal to the turnover.

Tariff differentiation between commercial and industrial consumers. This usually involves charging consumers engaged in production (the industrial group) somewhat lower tariffs as opposed to those engaged in distribution and services (the commercial group). This is often justified on economic grounds taking into account that, for the industrial sector, electricity is generally a more important production and cost factor than for the commercial sector, and that industries may find it more difficult to pass on electricity costs to their product prices than commercial consumers. Furthermore, the energy-saving potential of commercial consumers (lighting, air-conditioning) is generally greater than that of the industrial consumers (predominantly motor loads).

(For small consumer groups, where simple energy metering is applied and therefore does not permit adequate charging according to load factor etc., tariff differentiation may, of course, also be justified and correct in terms of cost-based pricing, simply on account of different group-specific load characteristics).

As noted, the present tariffs of CEB involve considerable cross-subsidies between consumer categories. While some price differentiation may no doubt be justified in accordance with the principles outlined above and should be retained, many of the existing cross-subsidies are clearly out of line and should be corrected. Particular aspects of this issue are further discussed below.

No price differentiation by electricity usage

No price differentiation by electricity usage should be applied (e.g. lighting, power, air-conditioning etc.). However, in line with cost-based pricing, tariff differentiation is, of course, justified if the characteristics of the loads are different (different load factor, different time of the day when supply is taken etc.).

Uniform tariffs throughout the supply area (no price differentiation by area)

Uniform tariffs should be retained within the supply area of an electric utility. This is in line with a policy of fair and equitable treatment of all consumers of the electricity undertaking and within the same consumer class.

Strictly cost-based tariffs would, of course require consumers in rural areas to be charged higher rates than those in the load centres, i.e. mainly urban areas. However, considering that the rural consumer group is generally also the lower income group, this would unduly penalize these consumers.

This means, for example, that the extra costs of the rural electrification programme should be borne equally by all consumers, the urban consumers thus subsidizing the rural supply areas.

Encouragement of efficient use of electricity

The need and requirement to encourage the efficient use of electricity and to save energy resources, in particular fossil fuel, is today an important consideration in tariff-making. Many utilities have thus for example adopted tariffs with a progressive rate structure (price increases as consumption increases).

While progressive tariffs may to some extent be in conflict with other economic or social considerations (e.g. industrial development), the minimum requirement should be that the rate structure is not degressive unless justified by cost considerations. (Decreasing average price with increasing energy consumption may be justified, provided the consumer's load factor is improved in the process. This can be provided for by adopting a two-part tariff with energy and maximum demand metering).

In general, properly marginal cost-based tariffs will tend to encourage the efficient use of electricity. This may involve review of the time-of-day rates (relationship between peak- and off-peak rates; duration of the peak period) or adopting a monthly fixed charge which increases as a function of the monthly energy consumption.

For Sri Lanka, the energy conservation aspect is particularly important in the light of the rapidly growing electricity demand and the increasing dependence of electricity production on fossil fuels.

Cost resilience of the tariff system

Tariffs should not be changed too frequently (except, of course, in a situation of high and continuous inflation). The tariffs should thus show some cost resilience and be able to absorb reasonably small changes in the cost of supply without prejudicing the financial performance of the undertaking. This may require building up adequate reserve funds to absorb to some extent fluctuations in fuel costs or foreign exchange effects. However, in the case of CEB, with inflation around 9 per cent or more in recent years, tariffs should be revised at least annually.

Other tariff guidelines

Other general tariff guidelines which should be observed include the following:

- Tariffs should be simple to apply and to understand.
- Tariffs should be easy to administer and be computer-friendly. The cost associated with metering and billing should thus be in reasonable relation to the total cost of electricity.
- Tariffs should be specific and exclude ambiguity. The criteria for grouping consumers into different tariff categories must therefore be clearly defined and justified (e.g. differentiation between "industrial" and "commercial" consumers).

2. Particular tariff issues of CEB

In addition or supplementary to the general tariff policy guidelines outlined above, there are a number of specific issues and objectives which are of particular importance to CEB, considering the present tariff structure and electricity supply situation. The main issues comprise:

Domestic electricity tariffs

The level of domestic tariffs is at present considerably below the actual cost of supplying this consumer group (average price of 2.8 SLRs/kWh versus an actual supply cost of about 7 SLRs/kWh). The domestic sector as a whole is thus substantially subsidized by the non-domestic tariffs. This is the case even for the larger domestic users, in spite of the progressive nature of the tariff. All domestic consumers now benefit from the low-price first block.

The present domestic tariff structure and rates need to be reviewed in the light also of the lower income group's ability and willingness to pay. The preliminary analysis suggests that, while some continuing subsidy appears justified for the low-income group, the prices paid by the average and large domestic users should be brought closer in line with the actual cost of supply.

It is also noted that the Asian Development Bank and the Government of Sri Lanka, in their loan agreement for the Second Power System Expansion Project financed by ADB, have agreed on the following covenant for the tariff reform for domestic consumers:

> The tariff restructuring shall include a simplification of the current domestic tariff structure (i.e. a reduction in the number of blocks) and the reduction of cross-subsidies to domestic consumers. In order to reduce the large cross-subsidies to domestic consumers which are inherent in the current tariff structure, average tariffs for domestic consumers shall be raised progressively over the next five years in such a manner that thereafter (i.e. after January 2001 the average domestic tariff shall equal or exceed the average tariff level). (Loan Agreement, Schedule 6, para. 18). It should be noted that "average tariff level" is understood to be the average level of the retail tariffs).

Classification of "general purpose" (commercial) and "industrial" consumers

The existing tariff system comprises essentially two non-domestic consumer categories, the general purpose (largely the commercial and public services group) and the industrial. While some differentiation between the two groups should be retained, it must be ascertained, as already noted, that the criteria for allocation of consumers to the two categories are specific and exclude ambiguity.

It is proposed that the existing classification should be thoroughly reviewed and that the criteria for allocation of consumers to the two categories should be revised. The industrial category should be clearly reserved for undertakings engaged in "production" e.g. large air-conditioning loads would thus not be sufficient justification for classification as an industrial load.

Hotels are at present charged under the industrial tariff. This does not seem justified, and hotels should be reclassified to be charged under the commercial tariff.

For small consumers, the clear distinction between a general purpose (commercial) and an industrial consumer may often be difficult. In view of this, the possibility of combining the two tariff groups (tariffs GP1 and I1) into a single "small non-domestic" tariff should thus perhaps be considered. This would require a considerable degree of harmonization of the tariff rates of the two groups. Average electricity prices now paid by the two groups are 5.70 and 4.35 SLRs/kWh respectively. While some price difference between the small commercial and industrial consumers is justified based mainly on the generally different coincidence factor of the two groups, the existing price difference appears clearly too high. This issue should be studied in more detail. The administrative advantage of having only one non-domestic small user tariff must thereby be weighted against the disadvantage – under a common tariff – of a probably somewhat unfair treatment of the industrial subgroup.

Effect of the rural electrification Programme

The rural electrification programme of CEB imposes a large financial burden on the electricity supply sector. Financing of the programme is at present subsidized by the Government by way of equity capital contributions (with no dividend charges applied). Considering the size of the rural electrification requirements, the proportion of the programme funded out of equity capital may decrease in the future and electricity tariffs will then have to be increased to recover the extra capital cost.

Effect of the significant increase in annual investment requirements

Considering the demanding power development plans of CEB, one of the important features of the tariff review is the expected sharp increase in the investment requirements over the medium and long terms (as compared with annual investments for example during the past few years). Capital charges will thus rise significantly in the longer term.

The government and CEB interest and depreciation policy will therefore be an important issue in establishing financial projections and the future revenue requirements and tariffs. All long-term loans to CEB essentially are by way of relending by the Government at an interest rate which is set at 13 per cent at present. The Government thereby absorbs all exchange risks.

Financial targets of CEB

Tariff rates and overall revenue from sales will have to be set to meet CEB minimum financial performance criteria, for example, the loan agreement with ADB stipulates a minimum rate of return of 8 per cent on average net fixed assets in operation (revalued). The following principal financial targets have been stipulated by CEB:

Rate of return of average net fixed assets (revalued)	8 per cent
Self-financing rate	30 per cent
Debt-service coverage	1.5 times

(The self-financing rate of 30 per cent is not a binding requirement for CEB; it is, however, a loan covenant for LECO.)

Retail tariffs of LECO

According to the Government's present policy, the retail tariffs of LECO are the same as those of CEB. This is in agreement with a general policy of non-differentiation by area of supply. However, it must be kept in mind that LECO is an independent distributor with a different consumer structure and a different cost structure from that of CEB. With retail tariffs fixed, the price for bulk supplies from CEB to LECO is thus essentially determined by the operating costs of the LECO system (including the need to make a reasonable profit).

The principle of equal tariffs for LECO and CEB will have to be reviewed. While much can be said in favour of uniform tariffs throughout the country (and among different distributors), it is in conflict with cost-based pricing and makes the establishment of inter-utility bulk rates somewhat arbitrary.

Electricity purchased from independent power producers

It is expected that in the longer term, private independent power producers will increasingly enter the electricity market in Sri Lanka, selling electricity in bulk to CEB. The first such project, which now appears to be firm, is a 50-MW diesel plant at Sapugaskanda; it will sell electricity to CEB at about 7 UScts/kWh.

While the formulation of power purchase agreements for major IPP projects is not part of the present tariff study (each agreement will be negotiated separately), the purchase of larger amounts of electricity from independent producers will, of course, have an effect on the CEB cost structure and thus eventually on the retail electricity tariffs. This is taken into account in the present study as far as firm IPP projects are identified within the study period.

There is also a programme for private mini-hydro schemes under way (funded by the World Bank). These small hydro plants will be connected to the CEB grid, and an energy exchange between the hydro scheme and the CEB system may occur (e.g. excess energy from the hydro plant being supplied back into the CEB grid).

Charges for standby supply

Partly as a result of the supply restrictions currently existing in Sri Lanka, there is an increasing number of large electricity users with their own generating facilities. These consumers will generally require a standby supply arrangement with CEB.

There is at present no special standby tariff, and it appears that CEB today generally charges normal tariff rates for consumers requiring standby supply (the Industrial time-of-day tariff). This is not a satisfactory price arrangement for either the supplier or the consumer of standby power.

The formulation of a suitable tariff system for standby supplies will be addressed in the present study. Such a tariff must provide for the recovery of the cost of the standby capacity provided by CEB. It must thus essentially be based on "subscribed" rather than actual maximum demand. Considering the relatively low probability of the standby power actually being required, the demand charge for the standby subscribed power can be set considerably lower than the normal maximum demand charge.

Granting of licences for the resale of electricity

According to the Electricity Act of Sri Lanka, licences for electricity suppliers (including licences for the resale of electricity) are granted by the Ministry of Energy (Chief Electrical Inspector).

Figure XVIII.18 Past development of domestic tariff average rate: real prices of 1996

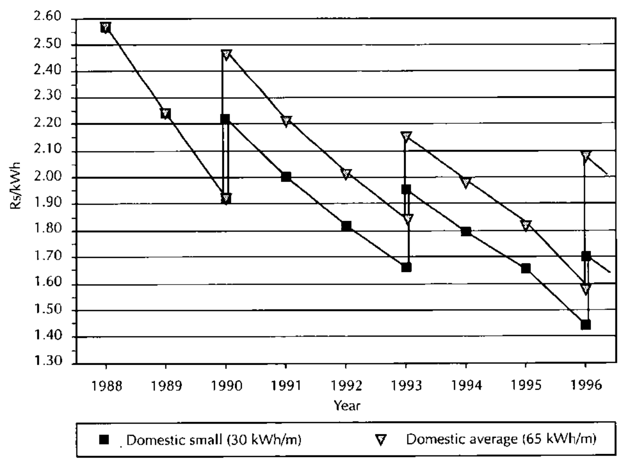


Figure XVIII.19 Past development non-domestic tariffs average rate: real prices of 1996

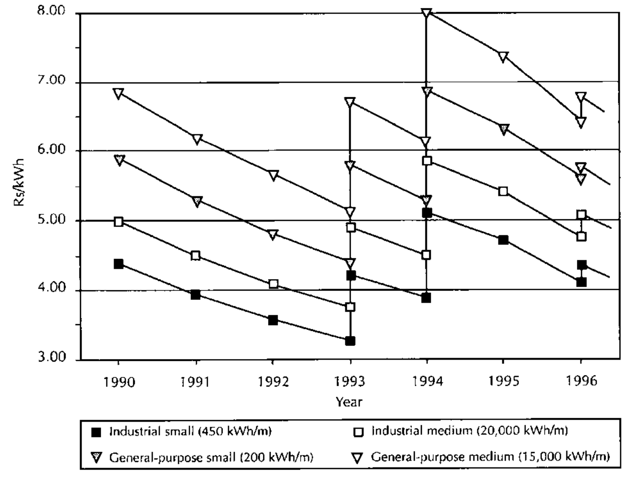


Figure XVIII.20 Average electricity costs, prices and cross-subsidies of CEB in 1996

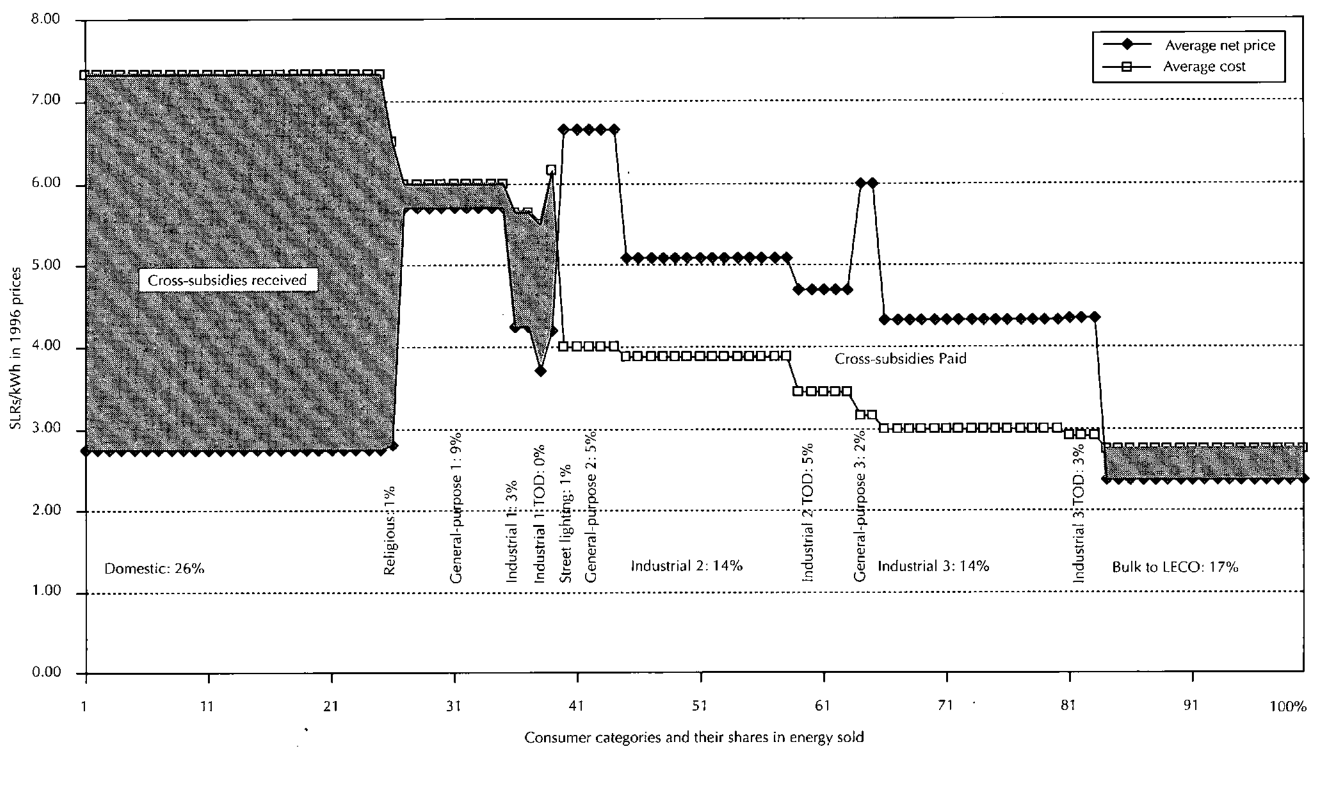
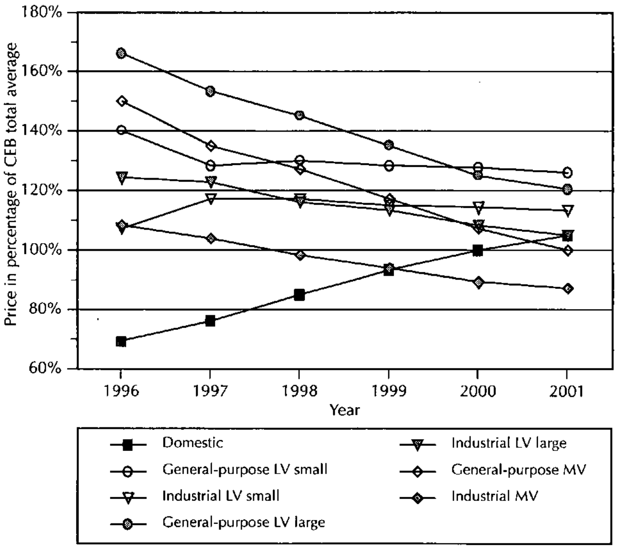


Figure XVIII.21 CEB development of electricity prices in percentage of CEB total average price



It appears that there is an increasing number of developers of high-rise buildings applying for a licence to distribute and sell electricity within their premises (buying at bulk rates from CEB). While the policy of licensing is outside the scope of this tariff study, the practice adopted by the Government could of course have a significant effect on the revenue situation of CEB. It is thus suggested that the Government, together with CEB, should carefully review the question of licensing within the CEB supply area.

Effect of fuel cost variation

In the longer term, with electricity from thermal plant expected to provide the major portion of energy generation, there will be no need for a special fuel cost adjustment clause in the tariff system, as overall fuel costs will be fairly predictable. Tariff rates will, of course, have to be adjusted periodically to account for increases in electricity costs owing to general fuel price increases (and for that matter increases in any other cost elements, as may be the case).

In the short term, with hydropower still providing the bulk of the energy, the situation may be somewhat different. Recent experience shows that annual hydro production in Sri Lanka can fluctuate greatly, depending on the hydro conditions. The need for supplementary thermal generation can thus also vary greatly with corresponding variations in annual fuel costs. Such fluctuations in overall electricity cost due to variation in the proportion of the supplementary thermal power should generally be absorbed by CEB without recourse to a tariff change. In order to allow for this, CEB could, for example, build up a special "fuel cost variation reserve fund".

J. PRICING POLICY

The energy pricing policy of Sri Lanka has been designed to achieve the following economic, financial and environmental objectives:

- Achieving economic efficiency in the production and utilization of energy
- Resource mobilization for financing investment in the energy sector as well as raising budgetary revenue for the Government
- Equity considerations in providing access to basic energy needs at an affordable prices to poor
- Stability in energy prices in the short run
- Environmental consideration such as the reduction of pollution and the protection of the environment

Thus, the energy-pricing policy has been aimed at achieving economic objectives such as efficiency, growth, stability and equity the financial objective, that is, the viability of the energy sector; and the environmental objectives. However, it is necessary to note here that most of these objectives are often not complementary and therefore a proper balance between them is essential in preparing a more effective and successful energy price.

Present energy pricing system

Under the present system of the price determination of domestic petroleum prices, the crude oil import price is adopted as the reference price. The likely exchange rate fluctuation during the pricing period is also taken into consideration. However, a part of the price impact resulting from the exchange rate depreciation is minimized by adjusting import levies. Finally, the rate of return of 10 per cent after tax on the CPC net assets is incorporated. Road-user changes for petrol and auto diesel are also included in the domestic petroleum prices through import duties and turnover taxes.

Similarly, the following factors are taken into consideration in determining the electricity tariffs:

- A target return of 8 per cent on the net revalued fixed assets of CEB

- The need for CEB to maintain a debt-service ratio of 1.5
- The goal of generating internally at least 30 per cent of the funds required for the capital investment programme of CEB

Furthermore, in order to promote better capacity utilization and minimize the investment in facilities required to meet demand levels, tariffs have been differentiated according to consumer categories, voltage levels and time of the day. A fuel adjustment surcharge is also levied if thermal electricity is generated during periods of drought.

XIX. ENERGY INFRASTRUCTURE OF THAILAND*

INTRODUCTION

During the Sixth National Economic and Social Development Plan, 1987-1991 the economy of Thailand grew rapidly at an average annual rate of 10.9 per cent, which is twice the Plan target. This rapid economic expansion has caused energy consumption to increase to 10.6 per cent a year. In the Seventh National Economic and Social Development Plan, 1992-1996, the annual average economic growth was 8.2 per cent resulting in energy consumption growth of 7.8 per cent a year. The growth target in the Eighth Plan, 1997-2001, is expected to be met, with an average of 8 per cent a year and annual energy growth close to 8 per cent.

A. ENERGY RESOURCES

Energy resources in Thailand consist of lignite, natural gas, condensate, crude oil and hydropower. Added to these are new and renewable sources of energy, such as fuelwood, paddy husk, bagasse, solar, wind, geothermal etc.

1. Lignite

The largest energy resource of the country is lignite, of which there are deposits mainly in the northern region of the country; in 1996, the average production was 58,841 tons per day or 6.3 MTOE, with a share of 14.8 per cent of the total indigenous energy production.

2. Crude oil

Crude oil fields were found in central and northern Thailand (onshore) and the Gulf of Thailand (offshore). The average production in 1996 was 26,292 barrels per day or 1.3 MTOE a year, a share of 3.1 per cent of the total indigenous energy production.

3. Natural gas

Most natural gas fields were found in the Gulf of Thailand or offshore, with some small volume onshore. In 1996, the average production was 1,286 MSCFD. The total production was 11.5 MTOE, or 27.0 per cent of the total indigenous energy production.

4. Condensate

Condensate fields were found only in the Gulf of Thailand. The average production in 1996 was 35,775 bpd. The total production was 1.6 MTOE, a share of 3.8 per cent of the total indigenous energy production.

5. Hydropower and others (geothermal, solar, wind)

Hydropower has been developed for power generation since 1964. In 1996, electricity generated from hydropower accounted for 1.6 MTOE, or 3.8 per cent of the total indigenous energy production.

Moreover, other energy sources have been used for power generation, such as geothermal solar cell and wind; in 1996, electricity totalling 0.001 MTOE was generated from these energy sources.

6. Renewable energy

Renewable energy (fuelwood, paddy husk and bagasse) sources are also the important sources, especially for rural area use. These accounted for about 47.5 per cent of the total indigenous energy production of 1996, or 20.2 MTOE.

B. CURRENT SITUATION

1. Energy demand

In 1996, Thailand consumed 53,517 kTOE, 53.2 per cent from petroleum products, 12.4 per cent from electricity, 10.6 per cent from coal and lignite, 1.7 per cent from natural gas and 22.1 per cent from renewable energy. This energy demand was concentrated in three major sectors, the transport, industrial, and residential and commercial sectors.

The transport sector is the largest energy consumer, accounting for 37.3 per cent of total energy consumption in 1996. All energy consumption in this sector was from petroleum products, mainly gasoline, LPG and diesel.

* Amorn Phundhu-fung, Department of Energy Development and Promotion, Ministry of Science, Technology and Environment.

The industrial sector ranks as the second largest energy consumer accounting for about 31.7 per cent of total energy consumption in 1996. The major energy consumed was renewable energy, with a share of 28 per cent of the energy consumption in this sector, followed by petroleum products, 27.9 per cent, coal and lignite, 22.3 per cent, electricity 17.6 per cent and natural gas, 4.2 per cent.

The residential and commercial sector consumed 26.6 per cent in 1996. The energy consumed in this sector comprised renewable 6.5 per cent, electricity 24.7 per cent, and petroleum products 10.3 per cent.

2. Energy supply

In 1996, the total energy supply of Thailand was 80 kTOE, 53.4 per cent from indigenous sources and 46.6 per cent from imported sources. Petroleum crude and petroleum products had the largest share, accounting for 93.9 per cent of the total energy imported; coal accounted for 5.9 per cent of the total energy imported, and electricity and renewable sources, 0.2 per cent.

3. Energy transformations

Thailand's energy system consists of three main energy transformation processes, which are electricity generation, petroleum refinery and gas separation plant.

(a) Electricity generation

In 1996, the total installed electricity generating capacity was 16,241.7 MW, comprising 2,909.5 MW hydropower, or 17.9 per cent; 6,807.5 MW oil/gas and lignite-fired thermal, or 41.9 per cent; 5,681.6 MW combined cycle or 35 per cent; 843.1 MW gas turbine and diesel or 5.2 per cent; in addition, some volume was purchased from neighbouring countries (Lao People's Democratic Republic, Myanmar).

(b) Petroleum refinery

At present, there are six refineries with a total capacity of 730,200 bpd, using domestic crude oil, 7 per cent, and imported crude oil 93 per cent, of which the main sources are the Middle East and ASEAN countries. In 1996, four refineries supplied 59.5 per cent of the country's total petroleum product demand. Another two refineries started to refine and supply petroleum products at the beginning and middle of 1996.

(c) Gas separation plant

Thailand has five gas separation plants with a total capacity of 1,244 MSCFD. Three of these are located on the east coast of Thailand, one in the north and one in the south. Two have a capacity of 350 MSCFD, followed by 250 and 230 MSCFD. The small-scale plant has only 44 MSCFD.

C. COMMERCIAL ENERGY DEMAND AND SUPPLY OUTLOOK, 1996-2001

The study of energy demand and supply projection in the next 10 years carried out by the National Energy Policy Office, using the regression method, shows the future profile to be as follows.

1. Energy demand

The rate of energy consumption in the country is derived from expansion of the economic growth, especially the main consumers from the industrial and transport sectors. The Energy Conservation Programme and the Demand Side Management Programme of the country also affect final energy consumption in the long term. The trend of energy demand still shows a big portion being taken up by petroleum products, accounting for a share of over 50 per cent in 2001 and 2006, followed by natural gas and lignite. Details are as shown in table XIX.1.

Table XIX.1 Share of various fuels in energy demand

(Percentage)

Type	*1996*	*2001*	*2006*
Petroleum products	63.7	54.8	53.0
Natural gas	17.0	28.4	21.6
LNG	–	1.3	6.1
Lignite and coal	16.2	13.0	17.2
Hydro and electricity (import)	3.1	2.5	2.1
Total	**100**	**100**	**100**

2. Energy supply

According to the study of the energy supply outlook, domestic energy supply will continue to be based mainly on natural gas and lignite, while crude oil will remain at a low level owing to the lack of

Table XIX.2 Share of domestic energy supply

(Percentage)

Type	*1996*	*2001*	*2006*
Crude oil	5.9	3.5	2.4
Condensate	7.3	8.9	8.9
Natural gas	51.5	58.6	58.1
Lignite	28.2	24.4	24.9
Hydropower	7.1	4.6	5.7
Total	**100**	**100**	**100**

additional large crude oil fields and the limitation of large domestic hydropower potential. The domestic resource supply is expected to be as shown in table XIX.2.

3. Electricity generation

With regard to the power development plan of the Electricity Generating Authority of Thailand (EGAT), a recent study shows that the total installed capacity will reach 29,201 MW by 2001 and 39,240 MW by 2006, from 16,241.7 MW in 1996. The study also takes into consideration clean fuel and the environmental impact on the surrounding area, including the cost-effectiveness of an installation of FGD (flue gas desulphurization). The proportion of electricity generation, classified by type of power plant, is shown in table XIX.3.

The Plan itself calls for more diversification of energy resources towards natural gas (both domestic and import) and imported coal in 2006.

Table XIX.3 Share of electricity generation by type of power plant

(Percentage)

Type of power plant	*1996*	*2001*	*2006*
Hydropower	17.7	11.6	11.6
Oil-fired	9.9	0.8	0.6
Oil/gas-fired	15.8	21.5	15.7
Lignite-fired	16.0	9.0	6.7
Coal-fired	–	6.0	19.0
Combined cycle	34.2	37.8	29.6
Gas turbine and diesel	5.1	3.0	2.3
Small power producers	1.3	8.2	6.0
Purchased	–	2.1	8.5
Total	**100**	**100**	**100**

4. Energy import

Owing to the limited supply of energy from domestic sources, the country remains dependent on net imported energy to meet future demand, mainly in crude oil and petroleum products, with shares of 44.6 and 21.6 per cent respectively by 2006. Other energy, such as natural gas and coal is imported to satisfy the fuel requirements in the power generation sector. Details are given in table XIX.4.

Table XIX.4 Share of imported energy by fuel type

(Percentage)

Type	*1996*	*2001*	*2006*
Crude	76.2	69.2	44.6
Petroleum products	17.7	6.7	21.6
Natural gas	–	13.4	10.1
LNG	–	1.9	8.0
Coal	5.9	7.4	14.7
Electricity (import)	0.2	1.4	1.0
Total	**100**	**100**	**100**

5. Pricing policy

In the past, the domestic prices of petroleum products were regulated by the Government to protect the economy. Subsidiary policies on some selective petroleum products were also made to reflect actual production cost and to be fair to both suppliers and users. Even though the petroleum consumption was still inefficient and wasteful, more petroleum products and crude oil were imported to support the demand, placing a big burden on the country. After 21 May 1991, the Government has approved two-step implementation of petroleum pricing:

(1) The first step, called "semi-floating" was introduced on 27 May 1991 whereby retail prices and marketing margins were floated, except for the ex-refinery prices, which were still regulated by the Government.

(2) The second step, called "fully floating", was launched on 19 August 1991 for gasoline, kerosene, diesel and fuel oil. The ex-refinery prices were also floated, depending on the refiners. In addition, surcharges were levied on imported petroleum products to protect the domestic

refiners. However, ex-refinery prices, particularly for LPG and bitumen, were still controlled by the Government.

6. Fuel policy

In order to identify and assess the possible various fuels available to meet Thailand's energy requirements over the next decade or two, there was a need to assess the increasing demand, the limited domestic energy resources, the environmental impact of energy production, the utilization and the security supply. Therefore, Thailand has conducted a study to examine the present status and possibilities of appropriate fuel cost, sources and conditions that should be obtained to meet the country's energy needs in different time frames.

From the results of the study, the power sector is the main consumer. Its installed capacity will be 31,800 MW in 2010 and the fuel requirement for power production will be 43 million tons of oil equivalent or 0.862 million barrels per day. Owing to public opinion opposing the nuclear power plant and its strong effect on Thai politics, the results of the study indicated that nuclear power ranks as the last alternative fuel, because there are so many problems concerning location, radioactive waste disposal, safety high cost, investment, and accidents caused by human error. The study also indicated the total cost for power generation to be as follows.

	US cents/kWh
Demand-side management (DSM)	2.1
Hydropower	2.6
Natural gas	4.0
Lignite (FGD)	4.9
LNG	5.2
Coal (FGD)	5.3
Furnace oil (sulphur content 0.5%)	5.3
Nuclear	7.5

D. POLICIES AND PLANS INFLUENCE THE FUTURE ENERGY SCENE

Owing to the possibility of a future energy crisis in the country and the big burden on energy supply investment, including the rapid growth in energy consumption, many policies and plans were implemented to improve efficiency in production and the use of energy to benefit the consumer and the country as a whole. The major policies and targets are as follows:

- ❑ Keep the growth rate of commercial energy consumption of the country abreast of the growth rate of GNP during the plan period
- ❑ Increase commercial energy production at a rate of 5 per cent a year during the Eighth Plan period
- ❑ Maintain the level of energy import-dependence at the rate of no more 70 per cent by the end of 2001
- ❑ Increase the electricity generating capacity by another 5,800 MW, purchase 2,700 MW of electricity from independent power producers and small power producers using non-conventional energy or co-generation in the amount of 1,900 MW during the plan period
- ❑ Set targets for reduction in electricity demand through demand-side management measures at the level of 1,400 MW and 3,846 GWh
- ❑ Reserve capacity of the electricity system at not less than 20 per cent of maximum electricity demand a year by the end of 2001

E. CONCLUSIONS AND RECOMMENDATIONS

According to the country's increasing energy demand in the past, petroleum products are still the dominant energy source and account for more than 60 per cent of energy and, owing to the small volume of domestic resources, caused more energy to be imported. Therefore, many issues and projects should be implemented to alleviate future energy demand. Some of these are as follows:

- ❑ To distribute a system for alternative energy sources and promote them to play an important role as major energy sources for instance, coal and natural gas as alternative fuels in power stations
- ❑ To propose an extension of new energy technologies on the oil refinery process to obtain more petroleum products and meet the country's requirements

- To propose new technology such as fluidized bed coal power plants, waste incineration and biomass plants, decentralized photovoltaics etc.
- To explore and analyse the specific problems and design appropriate solutions and technologies with joint R and D strategies with neighbouring countries
- To promote and accelerate gas pipelines with ASEAN countries
- To have less reliance on imported fuels and enhance environmental protection, energy conservation programmes and demand-side management should be promoted to achieve the target of reducing the country's energy demand as a whole.

XX. THAILAND: ELECTRICITY REVIEW*

INTRODUCTION

Thailand has been one of the fastest growing economies in South-East Asia. Electricity has played an important role in fuelling the growth of the Thai economy. From 1985 to 1995, GDP grew at an annual rate of 8.9 per cent and electricity consumption at 13.0 per cent, showing a strong elasticity of 1.46. Per capita electricity consumption nation-wide increased from 387 to 1,198 kWh, and that of the Bangkok area increased from 1,490 to 4,107 kWh during the same period.

Over the last two decades, the electricity sector of Thailand has grown from the infant stage to a relatively well-developed system. The total installed generation capacity increased from 2,438 MW in 1975 to 16,142 (excluding the 2,763 MW of private self-generation capacity) in 1996. Different regions of the country have been interconnected. As of December 1995, 98.9 per cent of the villages and 74.9 per cent of the rural households of the country were electrified.

A. ENERGY POLICY AND PLANNING

The energy policy of Thailand aims to ensure the availability of energy; promote free market competition in the energy business; implement energy conservation programmes; promote private investment in the country's energy affairs; and reduce the environmental impact from energy use.

To achieve these policy objectives, the Government takes the following policy measures: (a) entering into long-term energy contracts with neighbouring countries; (b) deregulation of the petroleum product price; (c) restructuring of electricity tariffs in line with marginal cost; (d) liberalization policy of free market competition and privatization through the sale of state enterprises in the financial market; (e) sale of electricity from the private sector to the national utilities; (f) launching of a demand-side management programme to reduce both expected peak load and electricity demand; (g) promulgation in 1992 of the Energy Conservation Promotion Act which gives legal entity to the Energy Conservation Fund to promote energy conservation; (h) encouragement of production and use of more environment-friendly petroleum products (unleaded gasoline); and (i) regulation of environmental protection equipment for coal-fired power plants and later on for cars.

Moreover, the Government, through the National Energy Policy Office (NEPO) provides energy policy guidelines for each of the five-year National Economic and Social Development Plans (NESDP). These guidelines vary from one period to another in order to cope with the changing situation of the economy. Under each policy guideline, NEPO also provides a detailed programme of action for each of the energy sectors. Quantified targets are set for the whole energy system during the planned period beginning from the Sixth Plan (1987-1991).

The energy policy guidelines for the Eighth Plan covering the period 1997-2001 include: providing an

* Koomchoak Biyaem, Director, System Planning Division, Electricity Generating Authority of Thailand.

Table XX.1 Public electricity sector of Thailand at a glance

	System operator	*System indicators*	
Generation	Electricity Generating Authority of Thailand (EGAT)	Total installed capacity (March 1997) Total peak demand (March 1997)	16 250.3 MW 14 043.5 MW
Transmission	EGAT		
Distribution	Metropolitan Electricity Authority (MEA) for the Bangkok region and Provincial Electricity Authority (PEA) for the rest of the country	Length of transmission line	23 202 circuit-km
		Number of substations	177
		Transmission voltage	500, 230, 115 and 69 kV
		Distribution voltage	33 kV, 22 kV
		Utilization voltage	230 volts

adequate amount of energy to satisfy demand while ensuring quality and security of supply and reasonable prices; promoting efficient and economical use of energy; promoting competition in energy activities and increasing the private sector's role; preventing and solving environmental problems resulting from energy development and utilization, as well as improving the safety of energy-related activities; and developing legislation related to energy and the energy administration mechanism.

Corresponding to the Government's policy guidelines on the electricity sector for each NESDP period, the Electricity Generating Authority of Thailand (EGAT) prepares a long-term power development plan. The present plan covers the period 1997-2011. The EGAT power development plan needs to obtain approval from the National Energy Policy Council, which is chaired by the Prime Minister, and the Council of Ministers (Cabinet).

B. KEY ISSUES OF THE ELECTRICITY SECTOR

Energy has been considered a crucial and fundamental production factor of the Thai economy, which depends on external sources for 62 per cent of its commercial energy needs. The electricity sector, while keeping the primary objective of supplying electricity with sufficient availability, high reliability and at reasonable cost, has received new definitions of its role in the Thai economy in recent years. Increasingly, Thai policy makers tend to consider electricity generation, transmission and distribution an important branch of the industry within the national economy instead of a public service. Consequently, important restructuring and reform processes are under way to make the electricity sector an open and dynamic industry, among other things.

From the international perspective, the Thai electricity sector has also been charged with new missions. From a traditionally big recipient of international loans that has created a heavy burden for the Government, Thai policy makers want to make it an attractive place for international investment, thus changing the status as loan seeker to that of contract officer. In a regional perspective, Thailand is the single largest market for electricity trade in the Greater Mekong subregion (Cambodia, southern China, Lao People's Democratic Republic, Myanmar, Thailand and Viet Nam), and the electricity trade is being used as a political and economic tool to enhance regional cooperation and stability, especially with neighbouring poor countries.

While the changing domestic role of the electricity sector requires deregulation and less government intervention, its new international role supposes that the springboard of the sector will still be in the hands of the Government. Properly managing both its new domestic function and international role will be an important challenge for the Thai electricity sector, whereas maintaining an appropriate institutional balance between public responsibilities and the private sector's interests is another.

Other key challenges of the electricity sector of Thailand include:

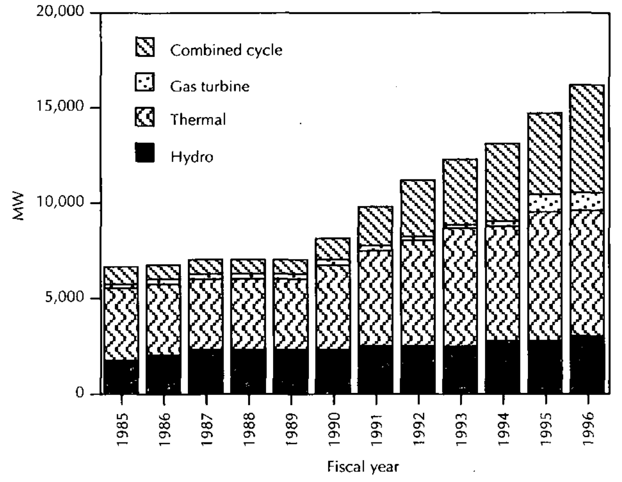
- ❑ Financing the rapid expansion of the sector with effective participation of the private sector
- ❑ Ensuring security of fuel supply to the power sector
- ❑ Managing the environment
- ❑ Managing the transition from public utilities to business groups for all three electric utilities (EGAT, MEA and PEA)
- ❑ Defining an appropriate post-privatization structure of the power industry to ensure fair competition and efficiency
- ❑ Adjusting the price of electricity to its real cost and removing the existing cross-subsidies
- ❑ Developing electricity trade with neighbouring countries
- ❑ Improving energy-use efficiency through demand-side management
- ❑ Building the domestic human resources for the power sector's business management

C. ELECTRICITY SUPPLY AND DEMAND

The country's total installed generating capacity rose to 18,905 MW, of which 85.4 per cent was from the EGAT power system and the remaining 14.6 per cent was the power capacity of a private power source and a hydropower plant of the State's energy-related agency.

Since early fiscal year 1995 (1 October 1994-30 September 1995) and March 1996, EGAT has sold and transferred its 1,232 MW Rayong power plant and 824 MW Khanom power plant to its subsidiary, Electricity Generating Public Company Limited (EGCO). The power capacity from Rayong and Khanom was then categorized as the purchased power in the EGAT power supply system. In the meantime, EGAT also added some newly completed power projects and some small power producers (SPPs) to its system.

Figure XX.1 Evolution of capacity mix by technology in Thailand

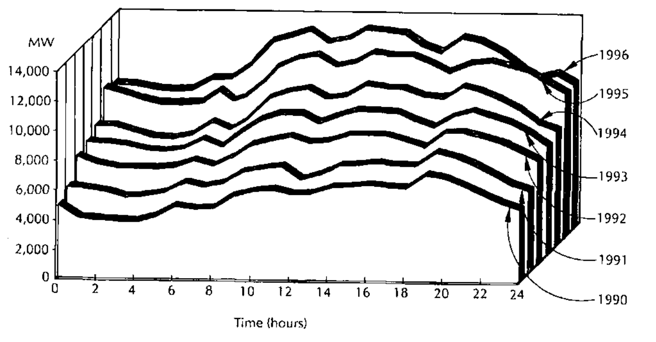


At the fiscal year end, the EGAT installed generating capacity amounted to 13,983 MW, or 4 per cent more than the previous year. Half the total capacity was of the thermal type accounting for 6,517 MW. The other half comprised 3,716 MW of combined cycle (27 per cent); 2,861 MW of hydropower (20 per cent); 872 MW of simple cycle gas turbine (6 per cent); and the trifling 17 MW of diesel plants and alternative energy sources.

The remaining 13 per cent share of the country's power system was the power capacity EGAT bought from its subsidiary, EGCO (2,056 MW combined cycle), from SPPs, 90 MW, and from a small hydropower plant of 13 MW operated by the State's Department of Energy Development and Promotion (DEDP).

The evolution of the public generating capacity mix during the period 1985-1995 is shown in figure XX.1. In the early 1990s, there was a strong penetration of combined cycle power plants. The share of electricity generated by those plants increased from 14.7 per cent of the total in 1990 to 34.8 per cent in 1996.

Figure XX.2 Evolution system gross peak generation in Thailand



The country's peak generation requirements rose to a new record of 13,310.9 MW on 22 March 1996 at 2 p.m. This was 1,043 MW, or 8.5 per cent, higher than the previous year.

The system's gross energy requirement totalled 85,924 GWh, 8.9 per cent up over the previous year. Eight-seven per cent of the country's energy needs, accounting for 74,460 GWh, was met by the EGAT power generation system, made up of 24,271 GWh (28 per cent) from natural gas-based generation; 22,514 GWh (26 per cent) from heavy oil; 16,770 GWh (20 per cent) from lignite; 7,234 GWh (9 per cent) from hydropower; 3,773 GWh (4 per cent) from diesel oil and the trifling 1 GWh from alternative energy demonstration plants.

The other 13 per cent of the country's supply, representing 11,464 GWh, was the energy purchase consisting of 9,782 GWh bought from Rayong and Khanom power plants of EGCO; 935 GWh from small power producers; 26 GWh from DEDP; and the remainder purchased from neighbouring utilities comprising 715 GWh from Electricité du Laos (EDL) and 6 GWh from Tenaga Nasional Berhad (TNB) of Malaysia.

Figure XX.3 Record of peak power demand and energy generation for the period 1985-1996

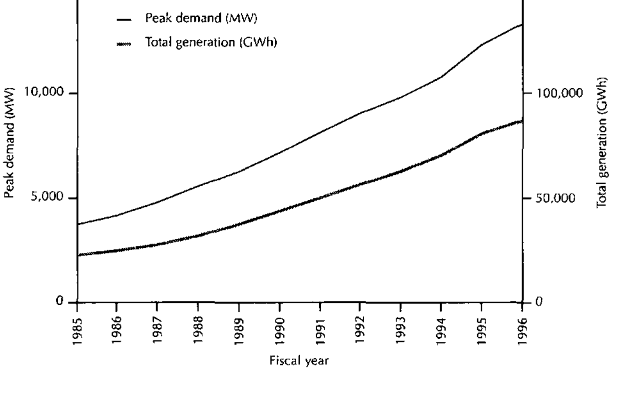


Figure XX.4 Evolution of electricity generation by fuel in Thailand

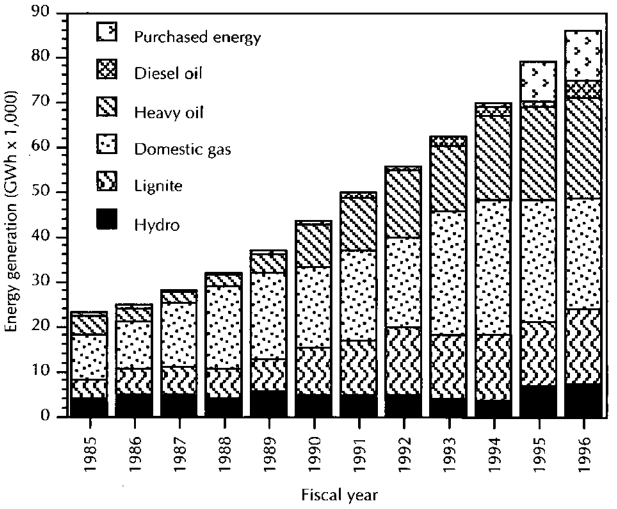
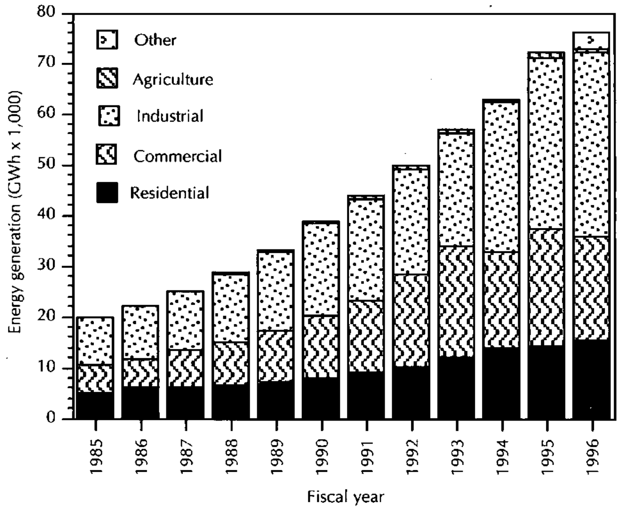


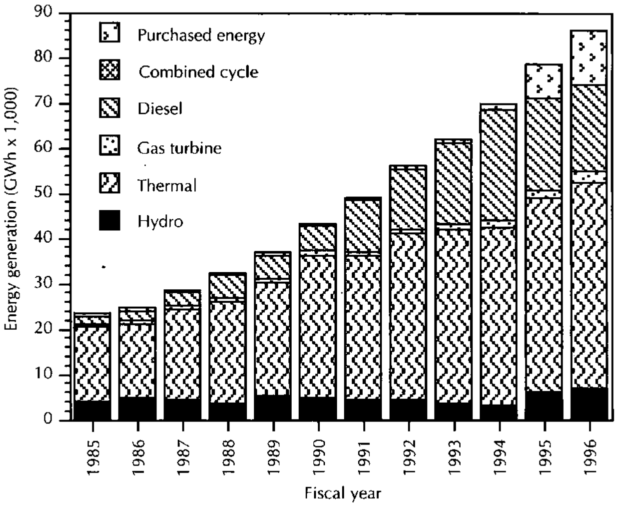
Figure XX.6 Evolution of electricity consumption by sector in Thailand



Of the total 85,924 GWh of electricity generated and purchased, hydropower accounted for 7,234 GWh (8 per cent), thermal: 45,310 GWh (53 per cent), combined cycle: 19,205 GWh (22 per cent), gas turbine: 2,705 GWh (3 per cent), diesel plants: 5 GWh and alternative energy plants (geothermal, solar energy and wind power): 1 GWh. The power purchased in the country was 10,743 GWh (12 per cent) and from neighbouring countries 721 GWh (1 per cent).

Of the total supply of 85,924 GWh in 1996, 2,618 GWh (3.1 per cent) was lost during transmission and 3,848 GWh (4.5 per cent) in distribution, and 3,855 GWh (4.5 per cent) was used by station services. The remaining 75,594 GWh was shared by the residential sector (20.6 per cent), the commercial sector (26.2 per cent), the industrial sector (47.7 per cent), agriculture and others (5.5 per cent). Over the period 1986-1996, industry was the most important consuming sector. The bigger portion of demand by the industrial and commercial sectors reflected the country's economic shift towards industrialization.

Figure XX.5 Evolution of electricity generation by technology in Thailand



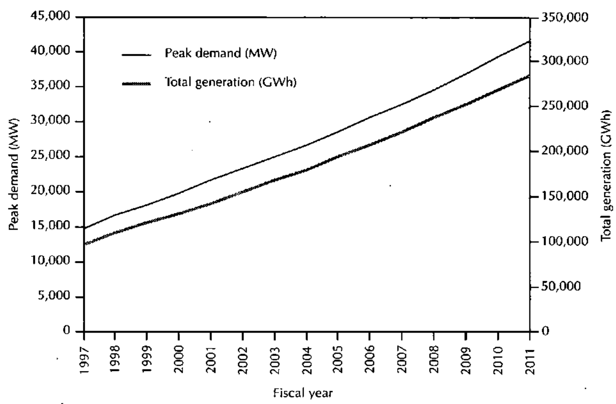
D. FUTURE GROWTH OF ELECTRICITY DEMAND

The electricity demand grew at an annual rate of 12.3 per cent during the period 1986-1996. This rapid growth was brought about by a high rate of urbanization, an aggressive electrification programme, swift expansion in the service and manufacturing industries, and a favourable pricing policy which made electricity use more economic compared with other fuels.

Peak power demand in 1996 reached 13,310.9 MW, a 8.5 per cent increase from the previous year's level. Total electricity generation in 1996 was 85,924 GWh, 8.9 per cent higher than in 1995.

The Thailand Load Forecasting Subcommittee (TLFS), composed of representatives of NEPO, EGAT, MEA and PEA, estimates the peak power demand to reach 21,423 MW in 2001 and 41,683 MW in 2011, and the electricity demand to reach 141,598 GWh in 2001 and 283,858 GWh in 2011. This corresponds to a slowing down of electricity demand growth to 9.9 per cent a year during the period 1997-2001 and to 6.9 per cent a year for the period 2002-2011. Figure XX.7 shows this future evolution.

Figure XX.7 Forecast of peak power demand and energy generation for the period 1997-2011



E. FUTURE ELECTRICITY SUPPLY OPTIONS

In satisfying future electricity needs, the Government of Thailand attaches great importance to both the environmental concerns and social acceptability of achieving the primary objective of providing cheap and reliable electricity. Choices of fuels must take into account the improvement in performance and fuel diversification from oil imports. Doubt about gas availability and opposition to hydropower schemes imply that the bulk of future power supply will rely on lignite and coal. Unfortunately, plants based on such fuels are likely to pose more environmental problems, as well as problems of reliability, because coal plants generally experience higher planned and forced outage than others.

Basically, Thailand has the following 13 sources for supplying electricity to meet the country's increasing demand: (a) hydropower; (b) domestic natural gas; (c) imported natural gas; (d) imported LNG; (e) oil, (f) imported orimulsion; (g) domestic lignite; (h) imported coal; (i) new and renewable energy; (j) imported electricity; (k) demand-side management; (l) nuclear power; and (m) purchase of electricity from the private sector.

1. Hydropower

Thailand has a total exploitable hydropower potential of about 7,007 MW, which can produce 18,410 GWh of energy annually. There is additional potential from pumped storage schemes of about 6,648 MW. Up to March 1996, only 3,874 MW, or 28.3 per cent, of the total potential had been exploited. Of this amount, 2,874 MW (531 MW pumped storage) has been in operation, and 1,000 MW of pumped storage capacity is under construction. The remaining potential is environmentally difficult to exploit. Any further development of hydropower resources will be limited to a few most economic, small-scale and environmentally benign projects. Pumped-storage projects will be the most competitive option to peaking gas turbine in the future. A total of 2,460 MW hydro capacity, all of pumped storage, is included in EGAT expansion planning for the period 1997-2011.

2. Domestic natural gas

The estimates of remaining natural gas reserves show about 18.8 trillion cubic feet. The bulk of the gas reserves (around 90 per cent) is located offshore the Gulf of Thailand. At an average production level of 1,650 MSCFD, it is most likely that the gas reserves of Thailand would be exhausted by 2015.

Currently, natural gas produced from the offshore platforms (mainly Unocal's Erawan field and TOTAL's Bongkot field) is transported by a 524-km pipeline to EGAT power plants at Bang Pakong and south Bangkok and the EGCO power plant at Rayong. Another pipeline of 330 km connects the Bongkot and Erawan fields and brings gas to the EGCO 674-MW combined cycle power plant at Khanom in the south peninsula. All gas pipelines in Thailand are owned and operated by the Petroleum Authority of Thailand (PTT).

3. Imported natural gas

Countries that can export natural gas to Thailand include Malaysia, Myanmar and Viet Nam.

Myanmar's Yadana field in the Gulf of Martaban is believed to have around 6.4 trillion cubic feet of natural gas. In September 1994, Thailand signed an agreement with Myanmar for the import of natural gas from this field to the Ratchaburi area through a 755-km long pipeline. Deliveries are to begin in 1998. The initial volume will be 125 MSCFD, but will rise to 525 MSCFD in 1999. If a pipeline was built to connect the recently discovery at Yetagun to the nearby Yadana field, this could add a further 200 MSCFD to the deliveries to Thailand.

The only possibility of gas import from Malaysia would be the purchase of its share of any gas found in the Thailand/Malaysia Joint Development Area (JDA) in the Gulf of Thailand. In view of the existing disagreements between the two countries regarding the pipeline route, gas imports from JDA in the best case will start by 1999 with a daily volume of 300-1,000 MSCFD.

In the longer term, there might be a possibility of importing gas from Cambodia and Viet Nam,, but this is unlikely to occur before 2010.

4. Imported LNG

LNG is commercially available in the South-East Asian region (Indonesia and Malaysia). However, it is more expensive than fuel oil and the LNG trade is still limited by the lack of port facilities. One LNG import terminal has been planned by PTT for start-up in 2003. The initial capacity will be 1 million tons a year, and this will increase to 3 million tons in 2005. Thailand has already signed a memorandum of understanding with Oman for the import of 2 million LNG a year for 25 years starting from 2003.

5. Oil

Thailand does not have many oil reserves. The proven reserves of oil/condensate have been estimated at only about 402 million barrels. The current rate of production is around 30,000 bpd, representing a reserve/production ratio of 10 years. Ninety per cent of the country's oil needs are satisfied by imports.

In view of its current low price, oil is considered an option for power generation. However, the policy of diversification from oil to ensure the long-term energy supply requires that all new oil-fired power plants be equipped with the dual-fire system. All the EGAT planned oil-fired plants therefore have natural gas as are alternative fuel.

6. Imported orimulsion

Orimulsion, an emulsified bitumen found in the 20,000 square-mile Orinoco belt of Venezuela, is also considered an energy source for power generation in Thailand. In fact, one IPP consortium has proposed a 1,353-MW project based on this fuel.

7. Domestic lignite

Thailand has a large amount of lignite reserves. Geological reserves are estimated at 2,330 million tons, with an estimated mineable reserve at about 1,470 million tons. However, for environmental reasons, the Government postponed the Lampang lignite-fired power plant indefinitely, and no new lignite-fired power project has been proposed for construction during the period 1996-2011. Nevertheless, in a longer-term perspective, lignite will remain an important option for power supply in Thailand.

8. Imported coal

EGAT considers imported coal an important option for its medium- and long-term planning. Its availability in the international market and stable price make it a competitive fuel, but this competitiveness is reduced by the requirement of using flue gas desulphurization (FGD) in all new coal-fired projects.

9. New and renewable sources of energy

Thailand has a large untapped potential of new and renewable sources of energy, especially solar and biomass. However, only around 490 MW of biomass-fired generation capacity has been developed, and about 228 MW are proposed for sale to EGAT.

10. Imported electricity

Currently, Thailand has an electricity trade with the Lao People's Democratic Republic (import/export), Malaysia (import/export) and Myanmar (export).

Located in the centre of ASEAN 7 + 3 (Lao People's Democratic Republic, Cambodia and Myanmar) and the centre of the Mekong subregion (Yunnan of southern China, Viet Nam, Lao People's Democratic Republic, Myanmar, Cambodia and Thailand), Thailand is the single largest purchaser of electricity in South-East Asia.

In view of the Government's policy of promoting peaceful co-prosperity and stability in the region and searching for alternative energy resources, greater efforts have been made to realize the joint development of energy resources with and the energy imports from neighbouring countries.

Imports from the Lao People's Democratic Republic

The Lao People's Democratic Republic is believed to have 20,000 MW of hydropower potential. At present, Thailand buys a total of 195 MW of hydropower from that country (150 MW from Nam Ngum and 45 MW from Xeset). In June 1993, Thailand and the Lao People's Democratic Republic signed a memorandum of understanding on the development and supply of up to 1,500 MW of electric power capacity in the Lao People's Democratic Republic for export to Thailand. Another memorandum of understanding was signed in June 1996 at the request of the Lao People's Democratic Republic for additional export of 1,500 MW. In addition, the Government has signed memoranda of understanding with several private investment groups (including the EGAT subsidiary EGCO) for the development of power projects that would export all output to Thailand. Twenty-four projects totalling 6,594 MW have been identified. Of these, three projects totalling 921 MW are under implementation and scheduled for completion between 1998 and 2002 (Theun-Hin Boun, Houay Ho and Hong Sa).

Imports from Malaysia

Thailand and Malaysia are interconnected through a 115-kV single-circuit line with an exchange capacity of 80-100 MW. The interconnection, which has served both countries in emergency situations, is very small compared with the overall capacity of the two systems. By increasing the exchange capacity through a high-voltage direct current (HVDC) transmission line, 300 MW of electricity can be imported from Malaysia in the future.

Imports from southern China, Myanmar, Viet Nam and Cambodia

Yunnan Province of China has 22,240 MW of hydropower potential. The Yunnan Provincial Electric Power Bureau (YPEPB) and EGAT have signed a memorandum of understanding to sell and purchase the power of 1,500 MW from the Jinghong Project.

The hydropower resources of Myanmar are also considerable, particularly in the Salween River basin adjacent to Thailand's border. Eight projects totalling 6,400-MW capacity have been identified and considered viable. Cambodia and Viet Nam also have significant hydropower resources which can be developed jointly for export to Thailand.

11. Demand-side management

Demand-side management (DSM) is considered a source of electricity supply. The accumulated DSM saving potential is estimated at 2,426 MW by 2011, and EGAT has an aggressive programme to exploit this potential.

12. Nuclear power

Nuclear power is another option for meeting Thailand's future energy needs. Because of its environmental cleanness (no conventional pollution emission) and energy supply diversification, EGAT considers it a feasible option, and has been involved in the studies of nuclear power for electricity generation for several years.

The last comprehensive study was carried out jointly in 1984 by the Office of Atomic Energy for Peace (OAEP), the National Economic and Social Development Board (NESDB) and EGAT under the guidelines and assistance of the International Atomic Energy Agency (IAEA). The results of the study indicated that nuclear power would be an economically competitive option for electricity generation.

Following the Government's energy policy guidelines for the Seventh National Economic and Social Development Plan (1992-1996) on the possibility of introducing nuclear power generation in Thailand, EGAT proposed for the first time in 1993 the inclusion of two nuclear power plants (2 x 1,000 MW) in its Revised Seventh Power Development Plan (PDP 92-01 (1)). It was planned that the two plants would be operational in 2006. The Plan was approved by the Cabinet in October 1993.

However, owing to strong public opposition, in June 1994 the Government announced the indefinite postponement of its nuclear power plan. In the current Plan for the period 1996-2011, no nuclear power plant is included.

Even though there is no firm plan for nuclear power, EGAT pursues a technological and human resources development, site selection, and information campaign. The public information programme aims to provide and disseminate knowledge and accurate information concerning nuclear power technology to various social groups, local communities and the general public, in order to create better understanding and eventually gain public acceptance of nuclear power.

13. Electricity purchase from the private sector

The last, but not least, option to satisfy Thailand's electricity demand is to purchase electricity from private producers. Private investors, motivated by the promise of good return, are eager to enter into the power generation business. Thailand has offered two schemes for their participation: the small power producers (SPPs) scheme and the independent power producers (IPPs) scheme.

F. ELECTRICITY DEVELOPMENT PLANNING OF EGAT

By 31 March 1997, the total installed capacity of the EGAT power system was 16,250.3 MW. Of this total, 6,517.5 MW was from thermal power plants, 3,715.6 MW from combined cycle plants, 2,867.4 MW from hydro plants, 872.0 MW from gas turbines, 16.6 MW from diesel, 0.534 MW of power from alternative energy sources such as wind, geothermal and solar power, and 2,260.7 MW of purchased power.

Based on the recent load forecast, an annual growth rate of electricity demand during the next 15 years will be in the range of 1,600-2,400 MW. In order to meet the future demand with higher reliability, EGAT has always prepared a long-term power development plan (PDP), which is revised occasionally to best suit the actual situation.

The latest EGAT preliminary power development plan includes both power and transmission projects to be implemented in 1997 and 2011.

According to the latest plan from 2001 onward, the system's reserve margin will be raised from the previous 15 per cent criteria to 25 per cent of the system's demand. New capacity totalling 37,034 MW will be added during the period 1997-2011, thus further boosting the total capacity to 50,597 MW by 2011 (reduction 2,578 MW of existing plant retirement). The capacity will be 52,907 MW if the additional purchase from SPP (1997-2000), 2,310 MW, is included.

The added capacity will come from the EGAT power projects, power purchase from the grid systems of neighbouring countries, namely, the Lao People's Democratic Republic and Malaysia, and also from the IPPs projects.

Of the total of 39,344 MW additional capacity proposed in the recommended plan for construction during the period 1997-2011, 22,514 MW is proposed for private undertaking under the IPP programme. IPPs are expected to bring about 1,700 MW of capacity before 2000, 4,114 MW during the period 2001-2003. By 2011, the share of IPPs in the total capacity will be around 42.6 per cent. This will be increased to 46.4 per cent if the two power plants at Rayong and Khanom purchased by EGCO from EGAT are included.

The IPPs are requested to secure their own fuel supply, and the technologies to be used by them are also to be determined by their developers. The planned technology mix of the future power generation system in Thailand is shown in figure XX.8.

According to the recommended plan, the total electricity generation in 2011 will be 283,858 GWh, 3.3 times the total output of 1996. EGAT has projected the future electricity generation by fuel as shown in figure XX.9.

Figure XX.8 Planned evolution of technology mix for power capacity in Thailand

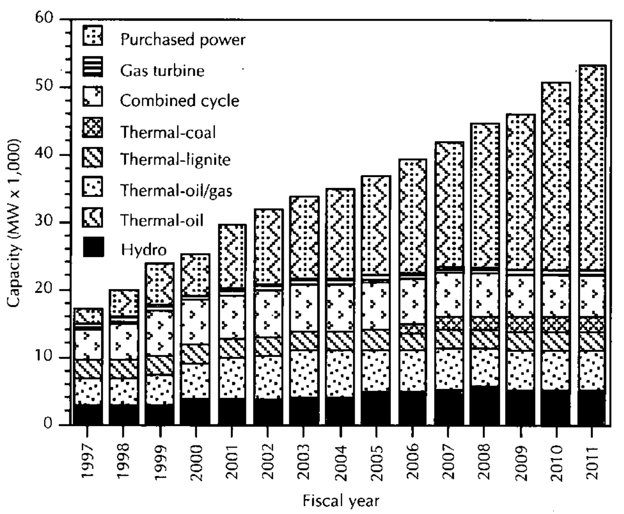
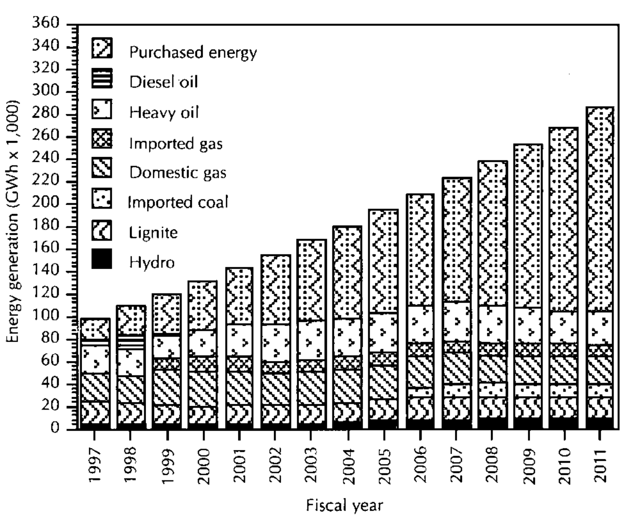


Figure XX.9 Planned evolution of power generation by fuel source in Thailand



G. STRUCTURE AND REGULATION OF THE ELECTRICITY SECTOR

1. Organization of the energy sector

The National Energy Policy Council (NEPC) chaired by the Prime Minister, is the highest-level organization for energy policy. NEPC has three committees: Electricity Policy, Petroleum Policy, and Energy Conservation and Alternative Energy. The National Energy Policy Office (NEPO) acts as secretariat to NEPC.

The electricity supply industry in Thailand is composed of three state-owned utilities: the Electricity Generating Authority of Thailand (EGAT) is responsible for electricity generation and transmission in the whole country. The Metropolitan Electricity Authority (MEA) is responsible for electricity distribution in Bangkok and two adjacent Nonthaburi and Samut Prakan provinces. The Provincial Electricity Authority (PEA) is the electricity distributor in all areas of the country except those under the responsibility of MEA.

While MEA and PEA are under the Ministry of Interior, EGAT reports directly to the Office of the Prime Minister. Another national energy company, the Petroleum Authority of Thailand (PTT), which runs all the oil and gas business of the country, is under the Ministry of Industry. Other energy sector institutions include the Department of Energy Development and Promotion (DEDP) under the Ministry of Science, Technology and Environment. DEDP also owns several small-scale hydropower plants with a total capacity of 51 MW.

The EGAT power system operation is divided into five areas: metropolitan area, central region, north-eastern region, southern region and northern region. Each of these five areas is interlinked with the transmission network and operated under the command of the National Control Centre (NCC) based at EGAT Headquarters, and five regional control centres.

The committed objective of EGAT is to provide an efficient power service to meet the requirements nationwide with sufficiency, reliability and at reasonable tariff rates, while enhancing and protecting the environment as well as encouraging public participation in its operation.

2. Historical evolution of the organization of the electricity sector

Electricity was first introduced into Thailand in 1884 by Field Marshal Chao Phraya Surasakdi Montri after his diplomatic mission to Europe. He purchased two electric generators and accessories from the United Kingdom of Great Britain and Northern Ireland. The trial operation of those first two pilot generators installed in the Front Army Department was such a success that His Majesty King Rama V ordered a power line extension to the palace. The palace was electrified for the first time on His Majesty's Birthday Anniversary, 20 September 1884, which marked the start of Thailand's electricity utility.

Power generation was undertaken by the Government in 1894 and transferred, in 1897, to a private company. In 1950, the Government took back the concession and the electricity service was handled by the Bangkok Electric Works (BEW). For provincial areas, the power supply in those early days was provided by municipal public works. The private sector was also allowed concessions in the power production.

In 1957, the Yanhee Electricity Authority (YEA) was formed to be responsible for providing power supply to 36 central and northern provinces. In the following year, the Government established MEA by merging the Bangkok Electric Works and the Electricity Division of the Public Works Department. MEA has been responsible only for power distribution in the metropolitan areas.

The Government established, in 1954, the Provincial Electricity Organization which later became the Provincial Electricity Authority (PEA) in 1960, to be in charge of power distribution in all parts of the country except for the metropolitan areas.

EGAT was formed on 1 May 1969 to nationalize and consolidate the functions and responsibilities of three independent state enterprises, the Yanhee Electricity Authority, the Lignite Authority and the North-East Electricity Authority. Thus began the new age of modern electricity in Thailand.

EGAT was the sole commercial producer of electricity in the country until 1992. Private companies could produce electricity for self-consumption, but were not allowed to sell it. According to the EGAT Act 1968 and subsequent amendments in 1978, 1984 and 1987, EGAT had the responsibility to provide electric energy for the whole country by generating, transmitting and selling the bulk energy to two distributing entities, MEA and PEA, other direct energy consumers as prescribed by Royal Decree, and neighbouring countries. EGAT could also undertake activities related to the production of electric energy, such as developing energy sources from natural resources.

The March 1992 amendment of the EGAT Act had two major impacts on the electricity supply industry in Thailand. First, section 37 (prohibiting the presence of private producers in the electricity generation industry) was suppressed, thus ending the monopolistic position of EGAT in electricity generation. The new legislation allowed private companies to produce and sell electricity. Second, the amended EGAT Act 1992 entrusted EGAT with new responsibilities including establishing a limited company or a public company for undertaking businesses concerning electric energy and other businesses concerning or in conformity with the activities of EGAT; collaborating in any activities with other entities, or holding shares in any limited company or public company limited for the benefit of the activities undertaken under EGAT objectives; and undertaking other activities concerning or in conformity with the achievement of EGAT objectives.

3. Deregulation and privatization

The main objectives of the deregulation and privatization of the electricity sector in Thailand are to improve the efficiency of the electricity supply industry in procuring electricity to satisfy the needs with good service, quality and fair prices, and to reduce the Government's investment and debt burden. It is believed that competition will help achieve such objectives and that the promotion of private sector participation in the electricity generation industry is crucial.

The deregulation of the electricity sector is part of the government policy for more private participation in state economic affairs. In November 1988, NESDB published a "White Paper on Enterprises" which recommended that, out of the existing 61 state enterprises at that time, 41 should be privatized by 2001.

In March 1992, the law on "Private Participation in State Economic Affairs" was promulgated to "ensure transparency, consistency and fairness in the privatization programme, especially for large-scale concession projects". Shortly afterwards, a Committee for Consideration of Increasing the Private Sector's Role in Cooperation to Develop State Enterprises was set up. The Committee identified 15 state enterprises for urgent privatization, including three electricity utilities and PTT. To encourage the commercialization of state enterprises as a first step to their ultimate privatization, the Government created the concept of "Class A State Enterprise" (or Excellent State Enterprise). The rewards for a state enterprise that achieved Class A status were the delinking of salary scales from those of the civil service and significant reduction in ministerial control.

The EGAT Act 1968 was amended in March 1992, opening the way for EGAT privatization as well as for private participation in power sector development. In May 1992, EGAT created a wholly owned subsidiary, Electricity Generating Company Limited (EGCO), to initiate the privatization programmes. The main responsibility of EGCO is to generate electricity and sell it to EGAT. To initiate private participation in electricity generation, the Government announced a plan to purchase 300 MW of capacity from SPPs using waste, renewable energy or co-generation. The upper limit of purchase from any SPP was set at 50 MW (later increased to 60 MW). The Regulations for the Purchase of Power from Small Power Producers were announced jointly by EGAT, MEA and PEA on 30 April 1992.

EGAT engaged a consulting firm to undertake the study "The Commercialization/Privatization of EGAT" for the long-term stable operation of EGAT. The study was completed and submitted to the Government on 29 June 1992. The Plan for Commercialization/privatization was reviewed and approved by the National Energy Policy Council and endorsed by the Government. The planned commercialization/privatization was to be completed in 1995/96 in four steps: (1) making EGAT a Class A state enterprise (1992/93); (2) restructuring EGAT into business units (1993/94); (3) converting EGAT into a public limited company and preparing to list EGAT on the stock market (1994/95); and (4) increasing the capital by listing EGAT on the stock market (1995/96) with the Government retaining the majority.

In September 1992, the Government passed a Cabinet resolution providing a four-step plan for the privatization of all Thailand's state-owned power utilities. The objectives of this privatization were stated as to lessen the Government's investment and debt burden in the public sector; to develop the operation of the state power utilities into the business-oriented organizations with more efficiency; to encourage more private sector participation in the power industry in the form of IPPs; and to utilize energy resources with the highest efficiency.

The plan includes issues regarding the restructuring of EGAT into business units, the corporatization of EGAT, the orderly participation of independent power developers, the privatization of EGAT, and the substantial restructuring and commercialization of the other two distributing utilities, namely, MEA and PEA.

The time-frame and the activities to be undertaken for each of the four steps were also provided by the resolution. They included the following:

Step 1: 1992-1993

- Diversify EGAT into a Good State Enterprise
- Change the bulk price to MEA and PEA to correspond to the long-run marginal cost (LRMC) of power generation
- Introduce business principles for fuel purchase
- Conduct the practical usage of an automatic fuel clause in electricity tariffs
- Establish an EGAT subsidiary – EGCO- and introduce its shares on the Stock Exchange of Thailand
- Abolish the uniform electricity tariff principle for the whole country.

Step 2: 1993-1994

- EGCO to buy Rayong power plant from EGAT
- Raise funds from the private sector to construct Mae Kham fluidized bed combustion (FBC) thermal project
- Prepare for private power producers to be responsible for some projects in the Power Development Plan for the period 1997-2001
- Restructure EGAT into business units
- Diversify MEA and PEA into Good State Enterprises and restructure PEA into regional business units with separate bulk tariffs for the purchase of power from EGAT

Step 3: 1994-1995

- Amend the EGAT Act (as well as the MEA and PEA Acts) and convert EGAT, MEA and PEA into limited companies
- Introduce EGAT on the Stock Exchange of Thailand and prepare EGAT to be a publicly owned company

Step 4: 1995-1996

- Diversify PEA into a business company with regional subsidiary companies
- Increase the share capital of EGAT and sell some of the equity capital on the stock market, while keeping the majority of the shares in the hands of the Government

In September 1994, EGAT became the second state enterprise, after PTT, to be ranked as a Class A enterprise. With its new status, EGAT could enter into commercially based contracts with other state enterprises for the sale of electricity (to MEA and PEA), purchase of fuel from PTT, and purchase of electricity from IPPs and other countries of the region.

In December 1994, as a first step in its privatization programme, EGAT sold the 4 x 300 MW Rayong combined cycle plant to EGCO. After the successful listing of EGCO in March 1994 on the Stock Exchange of Thailand, EGAT reduced its share to 48 per cent and EGCO became a public company in November 1994. EGCO later converted itself into a holding company with subsidiaries running individual power plants and selling electricity to EGAT under long-term power purchase agreements. It set up a Rayong Electricity Generating Company Ltd. (REGCO) to run the power plant purchased from EGAT. In March 1996, when EGCO purchased the 824-MW Khanom thermal power plant from EGAT, it established the Khanom Electricity Generating Company Ltd. (KEGCO) to run the plants.

Adopting the Government's policy to increase the private sector's role in power development, EGAT first started the purchase of electricity from the private co-generation and small-scale generation system of less than 60 MW each (SPP). The capacity available from this source will be initially treated as an extra power reserve margin to enhance security of the power system.

Large-scale IPPs have been invited to invest in several power projects. Pursuant to the Guidelines for the Purchase of Power from Independent Power Producers issued by the Cabinet on 31 May 1994, EGAT announced on 15 December 1994 the first solicitation to purchase electricity from IPPs of 3,800 MW (1,000 MW by 2000, 1,400 MW in 2001, and another 1,400 MW in 2002). This capacity was increased to 4,100 MW by the announcement of a supplemental notice in April 1995. As of 30 June 1995, the closing date for the submission of proposals, 104 registered bidders had formed 32 consortia and submitted 50 IPP proposals totalling 39,067 MW. Two consortia totalling 1,300 MW have been chosen to negotiate with EGAT for the construction of the first-phase IPP projects, and eight other consortia were shortlisted to negotiate for the 2,800 MW second-phase IPP projects.

A second announcement of bidding for the development of 2,300 MW of capacity for the period 2004-2006 will be announced in mid-1997. Unlike the first announcement, under which IPPs were free to propose the fuel, location, technology and pricing, the second announcement will specify the fuel to be used and the location of the power plants in advance.

It is planned that the total installed IPP capacity will reach 22,500 MW in 2011, or 42.5 per cent of the country's total system capacity.

In January 1996, the EGAT Board of Directors approved a new management structure in line with the Government's privatization policy. After the Board of Directors' meeting, EGAT requested the Government to review the Cabinet resolution of 12 September 1992 which had stipulated "privatize EGAT, register and sell shares in the Security Exchange of Thailand with the Government remaining a major shareholder". Instead of privatizing EGAT as a whole, EGAT requested that subsidiaries be established which would eventually be privatized and registered on the stock market and whose shares would be sold on the stock market as necessary when ready, or from fiscal year 1998 onwards.

The EGAT proposal also included a detailed plan for implementation as follows.

Fiscal year 1996: Commercialized management

- ❑ Restructure the organization into six business units (transmission, power plants, maintenance, mining, engineering and construction) and five operative units (policy and planning, accounting and finance, management, business development, and hydropower plants)
- ❑ Charge internal customers for products and services at the standard cost
- ❑ Practise business unit management for the first two quarters and evaluate the performance in order to improve the management and the standard cost charging
- ❑ Set the transfer price to be used between subsidiary company/companies and EGAT in fiscal year 1997 in the last two quarters
- ❑ Formulate business plan/plans for business units to be corporatized in fiscal year 1997
- ❑ Formulate programme plans and prepare the 1997 budget for the remaining business units and operative units

Fiscal year 1997: Establishment of limited companies

- ❑ Corporatize business units and other agencies which are ready to operate on a fully commercial basis, and register them as limited companies with 100 per cent shares held by EGAT
- ❑ Use the transfer price in charging the goods and services between EGAT and its subsidiary companies, and among the subsidiary companies
- ❑ Use the purchase contract for goods and services between EGAT and its subsidiary companies, and among the subsidiary companies

Fiscal year 1998: Establishment of public limited companies and listing on the Stock Exchange of Thailand

- ❑ Transform the subsidiary companies into public limited companies and subsequently list and sell their shares in the Security Exchange of Thailand to mobilize the needed capital for business expansion

Presented in this way, there will be no need to amend the EGAT Act. EGAT will still maintain the necessary profitable right in carrying out activities stipulated in the Act, for example, the right to make a survey and to run power transmission lines in individual lands. EGAT can still monitor and plan the production capacity, and transmission system, as well as ensure the unity of the production to enhance power system reliability and the profit of the country. EGAT can also continue to operate the hydropower plants which are related to various government agencies in the matter of water allocation. The use of land around the reservoirs remains the Government's responsibility.

In March 1996, the Government passed a Cabinet resolution, Direction of the Restructuring and Privatization of the Domestic Electricity Supply Industry. Following this resolution, EGAT was restructured into six business units (transmission, power plants, maintenance, mining, engineering, and construction) and five operative units (policy and planning, accounting and finance, management, business development, and hydropower plants).

Privatization of the Provincial Electricity Authority

On 28 November 1995, the Cabinet approved, in principle, the privatization of PEA. According to the privatization plan, PEA administrative authorities will be decentralized to its regions by separating the distribution utility into four regional offices (Central, excluding MEA jurisdiction, Northern, North-Eastern, and Southern), with PEA retaining the ownership and functioning like a holding company. The four regional offices will first operate as business units with individual cost and productivity goals. They will then be transformed into profit centres, that will have full responsibility in achieving revenue objectives and managing costs. Finally, these profit centres will evolve into corporations that will be independent entities engaged in commercial operation, and will form joint ventures with other private or public corporations.

PEA will also restructure its three other major activities (pole manufacturing, construction, and power generation) into subsidiary corporations following a similar pattern. PEA hopes to receive Class A enterprise status in 1996. Further, the PEA Act 1960 needs to be amended to allow PEA to set up a subsidiary and to enter into joint ventures with the private sector.

Privatization of the Metropolitan Electricity Authority

Compared with the other two electricity utilities, MEA has more difficulties in moving to commercialization, first restructuring into a corporation and ultimately to privatization. The management has not been confident that it can address the issue of staff redundancies without industrial disputes and disruption of its operations. Nevertheless, it has applied for Class A enterprise status, and if qualified, it will either follow the EGAT approach to restructuring its operation into business units and operative units, or follow its own transformation methodology, to be approved by the Cabinet, in 1997/98.

4. Future structure and regulatory framework of the electricity sector

The Subcommittee on the Coordination of Future Structure of Electricity Supply Industry of NEPC has proposed the following medium-term (1996-1999) structure and long-term (2000-2005 onwards) structure of the electricity supply industry in Thailand.

Medium-term (1996-1999) structure

The main activities in the medium term are to implement the corporatization/privatization plans of EGAT, PEA and MEA.

Generation. More private producers will be introduced. They can be SPPs, IPPs, EGCO subsidiary companies, or corporatized EGAT generation companies. Competition will begin in the electricity generation activities.

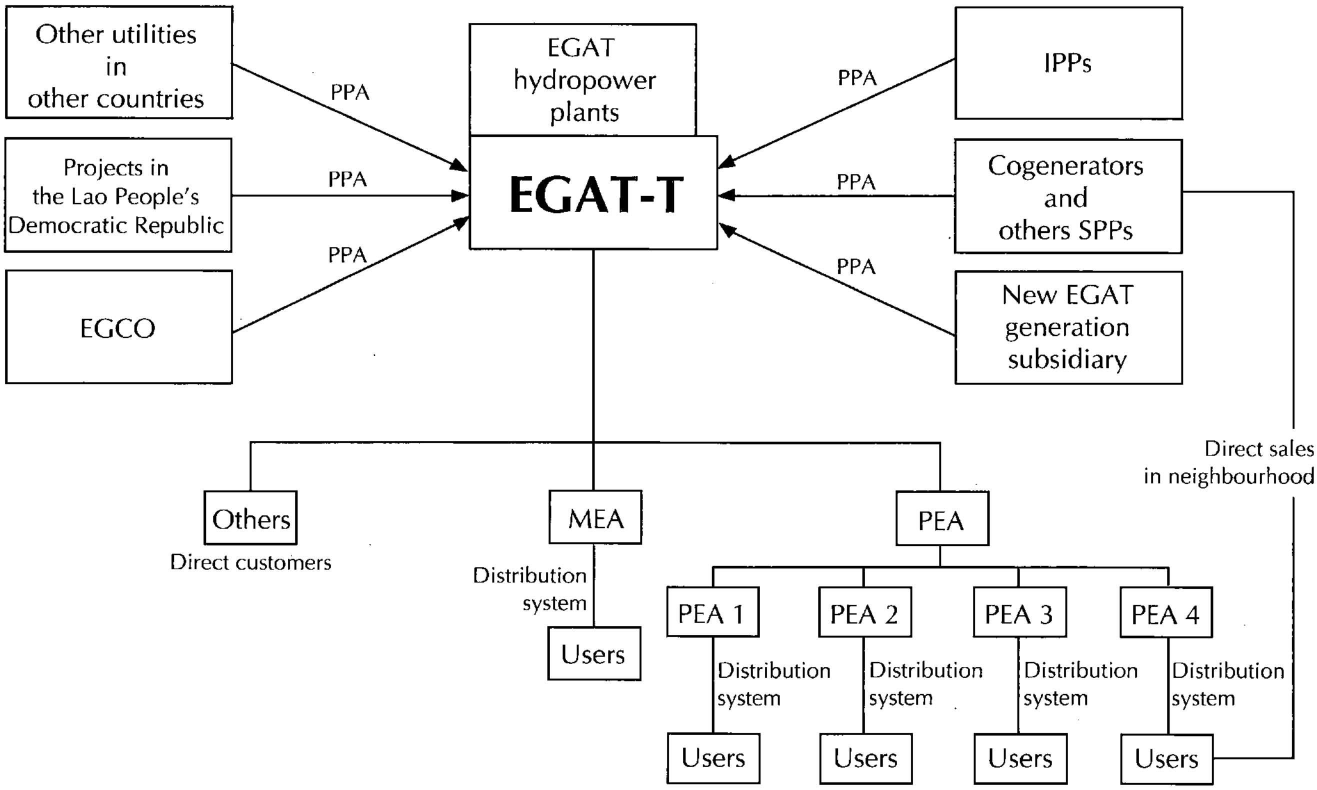
Transmission. The transmission lines will still be owned by EGAT but will be seperated as a business unit. It should maintain impartiality when considering power purchases from different producers.

Distribution. The distribution companies will reorganize their management to be more commercialized but will remain as state enterprises and continue distributing electricity in their respective areas.

Regulation. The imperfection of the market mechanism for competition during this initial period necessitates the intervention of the Government. NEPC/NEPO will retain the legislative authority to regulate the electricity supply industry during this period, but there will be a revision of the regulating principles by putting more emphasis on the improvement of efficiency and service quality.

The planned medium-term structure of the electricity supply industry in given in figure XX.10.

Figure XX.10 Electricity supply industry structure in the medium term



Long-term (2000-2005 onwards) structure

The activities of generation, transmission and distribution will be clearly separated and run by limited companies. The Government will decrease its role in these activities by promoting private participation instead, and/or selling shares to the public.

Generation. Private producers (IPPs, SPPs, EGCO and the privatized generation companies of EGAT) will produce electricity on a competitive basis.

Transmission. The Government will have strong control over the transmission company but will seek strategic partners in running the business. The transmission system will eventually become a common carrier which will provide producers with opportunities to sell electricity directly to consumers with a fair wheeling fee.

Distribution. There will still be only one distributor in each area. However, the distribution system will also become a common carrier which will allow consumers to buy electricity directly from producers through the use of transmission and distribution line services. This will enhance full-scale competition and provide more options to consumers.

Regulation. An Independent Regulatory Body will be established to regulate the electricity supply industry, to ensure its full-scale competition under the market mechanism, to create confidence among private investors, and to provide fairness to both investors and consumers. The regulations would most likely be incentive-based, with incentives for the electricity supply industry to do business with efficiency for the real benefit of consumers.

Rural electrification functions in the privatized power supply industry

Rural electrification is not a major issue in Thailand, as the country is already highly electrified. The Government plans to bring the electrification rate of rural households to 98.9 per cent by connecting 526,630 additional rural households. The main issue is the continuation of electricity services to rural areas.

In order to achieve this, the Government will continue its support to the rural electrification programme and maintain the lifeline tariff for small and presumably poor consumers. Privatized distribution companies will be obliged to supply electricity to those financially non-profitable areas. A bonus/penalty system will be established by the Government for this purpose.

H. ELECTRICITY PRICING POLICY AND STRUCTURE

The electricity tariff in Thailand is controlled by the Government. Any tariff change requires approval from both the National Energy Policy Council, especially its Committee for Energy Policy, and the Cabinet. The Committee has a Subcommittee for the Consideration of Electricity Tariff which is composed of representatives of various energy-related organizations and is responsible for setting the electricity tariff.

1. Pricing policy

The basic principle of Thailand's electricity pricing is quite similar to that of many countries in the region. It addresses the need to provide utilities with sufficient net revenue to continue their operations efficiently and finance the future expansion of the system, and more recently to reduce the system peak load, ensure system reliability, and promote efficient use of electricity. It also addresses the issue of equity, particularly the regional disparities, by making electricity available to lower-income households in the rural areas.

A unified tariff rate is applied across the country, i.e. consumers in provincial areas and in Bangkok have the same tariff rates. To maintain this uniform tariff policy, the EGAT wholesale tariff to PEA is much lower than that charged to MEA, as the costs of supplying electricity to PEA are higher. The bulk supply rates are the single flat-rate energy charges only, regardless of capacity demand and time of the day.

The current wholesale tariff of EGAT, effective 1 January 1995, is 5.82 USc/kWh to MEA and 4.27 USc/kWh to PEA. Direct consumers of EGAT are charged at rates of the large general service category, with the same terms and conditions as those of MEA and PEA rates.

2. Retail price structure

The main considerations in setting the retail tariff include the marginal cost of supplying electricity at different voltage levels; the financial requirement of utilities; the load pattern of customers; and the social and political factors (e.g. rural electrification).

The existing structure of retail tariffs in Thailand, which was introduced in December 1991, is based on the long-run marginal cost (LRMC) of power supply at different voltage levels. The current average tariff (6.58 USc/kWh) has been set by the Government at about 80 per cent of the average LRMC. However, the Government allowed two deviations within the tariff structure from the general principle of pricing at cost to take account of equity, and social and developmental considerations: MEA consumers pay tariffs that exceed the cost of service and as a group subsidize PEA consumers; and the residential category is subsidized by other consumer groups, with a lifeline tariff in effect for customers with consumption of less than 150 kWh/month.

In September 1992, an automatic adjustment mechanism (called F_t) was introduced. This is to cope up with the uncontrollable and unexpected expenses that have not been covered in the designed base tariff. They comprise the change in cost of fuel, land and premises taxes, value added tax (VAT) and DSM expenses.

Three forms of tariff are used in Thailand: energy charges alone (for residential sector, small general service, government and NGO, and agricultural pumping), energy plus demand charges (medium and large general services and specific business), and time-of-day (TOD) rates. The TOD tariffs were introduced in January 1990. Initially, they were applied to consumers with a demand greater than 2,000 kW. Starting from December 1992, they were also applied to consumers with demand in excess of 30 kW and energy in excess of 355,000 kWh per month.

3. Proposed scheme to remove subsidies

As consumption grows faster in the PEA area than in the MEA area, the existing cross-subsidies cause more losses for EGAT. To gradually reduce this cross-subsidy, the Government of Thailand intends to first make it transparent in the accounting system as well as in consumers' electricity bills. The Government will also create a zero-balanced administrative account, in which EGAT and MEA will transfer the additional earnings to their allowed earnings, and the whole amount will be given to PEA. The responsibility of cross-subsidy will thus be transferred from the power utilities to the Government. EGAT will then charge the same bulk supply rates to PEA and MEA. The Government will also maintain subsidies to poor people: a lifeline tariff system to those households using less than 150 kWh/month.

I. EVOLUTION OF POWER SECTOR FINANCING IN THAILAND

Publicly owned, the electricity utilities in Thailand relied heavily on government financing. The goal of the Government was to maintain the self-financing ratio of the electricity sector at not less than 25 per cent of its capital investment. However, during the period 1970-1979, for example, EGAT borrowing from foreign and domestic sources represented as much as 60 per cent of its total investment of about $980 million. In the late 1980s, the level of borrowing increased tremendously, and the situation of MEA and PEA was not very different from that of EGAT.

Huge debt was one of the key issues in the power sector of Thailand. The debt-equity ratio of EGAT increased significantly in the 1980s, with ratios largely exceeding the level of 60 per cent, one of the highest in the region. Debt service attained 140 per cent of capital expenditure in 1988. The situation of MEA and PEA was comparable. The MEA debt service as a proportion of capital expenditure surged from a level of 12 per cent in 1975 to 51 per cent in 1988, while that of PEA swelled from only 5 per cent in 1970 to 73 per cent in 1988.

Much of the debt was in foreign currency. Between 1980 and 1986, for example, foreign loans amounted to about $2.7 billion, representing around 90 per cent of the total borrowing. The sources of these foreign loans included development banks (World Bank, Asian Development Bank), commercial banks, and suppliers and buyers credits.

To improve the financial situation of the power sector and restore its viability, the Government took major decisions in the early 1980s, including tariff increases, equity contributions and fund transfers. The situation was, however, far from sound, especially in the light of the future capital needs to finance the expansion of the power system.

The electricity sector accounted for more than 90 per cent of government investment in the energy sector. During the Sixth NESDP period, 126.6 billion of the 132.6 billion baht ($5,200 million) of total energy sector investment went to the electricity sector, of which 73 per cent was for EGAT and the rest for PEA and MEA. Under the current Seventh NESDP (1992-1996), 269.5 billion of the total of 282.3 billion baht ($11,070 million) government energy sector investment would be spent on the electricity sector.

J. FUTURE INVESTMENT REQUIREMENTS FOR THE POWER SECTOR

The take-off of the Thai economy since 1987 has put considerable stress on electricity sector financing. During the period of the Sixth NESDP (1987-1991), about $3,600 million ($720 million per year) was required to finance EGAT power sector expansion. This amount exceeded by far the total investment in the power sector over the previous 15 years. If EGAT were to continue financing the power sector's expansion alone, it would need $1,355 million per year in the Seventh Plan period (1992-1996) and $2,196 million per year in the Eighth Plan period (1997-2001). About 52 per cent of this amount will be in foreign currency for imported equipment and machinery. To maintain national financial stability, the Government has limited the overall borrowing by the public sector to $3,700 million a year, of which 30 per cent has been taken by EGAT owing to its capital-intensive activities. EGAT has to face this financial constraint and cannot depend further on government debt and foreign loans for future investment.

Starting from the Sixth NESDP (1987-1991), increasing stress has been put on the private sector to play a more central role in the whole national development process through involvement in infrastructure development. The Government in its policy guidelines for energy sector development during the Seventh (current) and Eighth Plans, consistently calls for more private participation in power development projects.

As a result, the new EGAT Power Development Plan allocated 22,500 MW of power generation capacity to the private sector for the period 1997-2011. This would reduce the future investment requirement of EGAT considerably.

K. SCHEMES FOR PRIVATE PARTICIPATION IN POWER DEVELOPMENT

Private capital can be mobilized in a number of ways: sale of bonds to domestic and foreign lenders, ventures consisting of Thai-only corporations or consortia, joint ventures between Thai and foreign companies, or investments by foreign firms alone. Despite the relative ease in raising funds from the domestic market through the sale of government securities and bonds, the Government of Thailand is not keen on attracting private capital through this method. The reason is that this would be a passive way, bringing no improvement in management, no new technology and no market-running mechanism. Instead, the Government has invited the private sector to invest directly in power generation or to purchase some assets of EGAT.

Apart from reducing the Government's investment burden in the energy sector, private sector participation will also encourage competition in the choice of power plants and location, fuel types and technologies.

Three schemes have been put in place for private sector participation in power sector development: (1) participation in the EGAT subsidiary company; (2) through the small power producers programme; and (3) through the independent power producers programme.

1. Subsidiary company of EGAT

In May 1992, EGAT created its subsidiary company, the Electricity Generating Company Limited (EGCO) with a capital of 100 million baht ($3.922 million). Its objective was to raise funds from the financial market to purchase power plants from EGAT, develop its own power projects, and eventually become a competitor of EGAT in the power generation business.

EGCO was registered on the Security Exchange of Thailand (SET) in March 1994. After its successful public offering to both international and domestic investors in October and November 1994, EGAT reduced its shares to 48 per cent. In December 1994, EGCO raised the required 17 billion baht ($667 million) and purchased the 4 x 308 MW Rayong combined cycle power plant. In March 1996, EGCO purchased another power plant from EGAT, the 824 MW Khanom thermal power plant. EGCO is now a holding company with a subsidiary company to own and operate each of the power plants purchased from EGAT.

2. Small power producers

The SPP scheme was introduced in March 1992 immediately following the amendment of the EGAT Act. Its purpose was to initiate private participation in power sector development. The objectives of purchasing electricity from SPPs were (1) to reduce the financial burden on the Government in electricity generation and distribution; (2) to encourage participation by private producers in electricity generation; (3) to promote the use of indigenous by-product energy sources and renewable energy for electricity generation; and (4) to promote the more efficient use of primary energy.

Regulations for the purchase of power from SPPs were first published in April 1992 and revised in November 1994. The revised regulations allow any single SPP to sell up to 90 MW of electricity to EGAT. Electricity purchase from SPPs is priced at the avoided cost of EGAT (1.1 baht/kWh). But the source of SPP generation must be from non-conventional energy such as wind, solar and mini-hydro energy; waste or by-products from agricultural and industrial activities; and co-generation using natural gas or petroleum products under a number of conditions.

As of March 1997, there were 84 generating facilities proposing to sell 4,493 MW to EGAT under SPP contracts. Twenty-one SPPs have proposed to sell 255 MW to EGAT under non-firm supply contracts, and 63 SPPs with the combined capacity of 4,238 MW under firm supply contracts. Sixteen SPPs with a combined capacity of 140 MW, have already signed electricity selling contracts on a non-firm basis, and four SPPs (325 MW) on a firm basis.

3. Independent power producers

The IPP programme will serve as a new financial source for the investment in new capacity. Out of the total capacity addition of 39,344 MW during the period 1997-2011, EGAT is expecting IPPs to build 22,514 MW, or 57.2 per cent of the total capacity addition. This consists of 1,700 MW to be completed within the period 1999-2000, 2,773 MW to be commissioned in 2001 and 1,341 MW in 2002-2003.

The preliminary terms and guidelines for the purchase of power from IPPs were approved by the Cabinet in May 1994. The guidelines indicate that the proposals submitted for IPP projects must be in line with the 1994 power purchase solicitation document. This document consists of three parts:

(1) *Request for proposals* provides the bidders with clear guidelines and instructions in preparing and submitting proposals. It also discusses issues associated with other two parts of the solicitation document and other relevant issues.

(2) *Model power purchase agreement* is the prototype of the written agreement between EGAT and an IPP with regard to the sale of electricity by the latter to the former. The model PPA specifies operating characteristics, availability payment, energy charges, environmental quality standard, fuel supply and fuel purchase agreement, new transmission facilities and construction schedule, contracted milestones, liquidated damages, force majeure etc..

(3) *Grid Code* identifies the connection procedures, power plant operation and generation dispatching that the IPP has to follow. In relation to the requirements of the Grid Code, EGAT will have a connection agreement with the IPP which will specify the terms under which the IPP will be connected to the EGAT power grid.

The 1994 solicitation document specifies in particular that IPP will build, own and operate the power plant and provide the fuel for power generation. It stipulates that the fuels to be used must be environmentally clean, acceptable to the public, have a stable price and assured supplies, and support the government policy on the fuel diversification of the country. Natural gas, including LNG, hydrocarbon gas and its associated liquid, coal and orimulsion, were considered acceptable by the 1994 solicitation document.

The Government has formed the Committee on Evaluation and Selection of Proposals for Power Purchase from IPPs to evaluate and select proposals and notify bidding awards. The criteria for evaluation include project viability, level of development, fuel type and diversity, site location, utilization of local manpower and resources, project connection costs, security, experience of the bidder, identifiable societal and economic benefits to the community, financial resources of the bidder and the ability of the bidder to arrange financing for the construction of the project, technical appreciation of the work to be performed, exceptions to the proposed PPA, environmental impact, dispatchability and other factors that may affect the overall cost and/or schedule.

IPP projects may benefit from the incentives and privileges awarded by the Board of Investment (BOI). These privileges include: (1) an income tax exemption for three to five years under normal circumstances, or eight years in exceptional cases; (2) accelerated depreciation of the cost of installation or construction facilities; (3) approval to remit money in foreign currency to repay money brought into the country, plus dividends and interest; (3) authorization to lease or otherwise exclusively occupy and use land otherwise prohibited under the Land Code; (4) authorization to bring in alien experts, technicians and staff (including family members), otherwise prohibited under the Administering Alien Employment Act; (5) exemption or reduction in import duties on equipment and machinery used in the construction and operation of the project; and (6) certain guarantees and protection from nationalization of assets, state competition, state monopolistic purchasing policies or price controls.

The incentives/privileges vary according to the geographical location, with more incentives awarded to projects located away from the Greater Bangkok area. This is to promote regional dispersal of industries and regional development outside Bangkok. Typical incentives for IPP projects located in the Greater Bangkok area (Zone 1) and 10 well-developed provinces (Zone 2) include reduction in import duties by 50 per cent for some power generation equipment items; and exemption from income tax for eight years. Incentives for the other 57 provinces (Zone 3) include exemption from import duties; exemption from income tax for eight years; and reduction of income tax by 50 per cent for an additional five years.

Electricity generating and selling do not fall within the scope of restricted business under the Alien Business Law. Thus, an IPP project can be owned 50 per cent or more by foreign investors. However, the Government of Thailand might consider in the future a minimum degree of Thai participation.

L. ENLARGED PRIVATE PARTICIPATION

There will be more possibility for private participation in power sector development because of the well-advanced privatization plan of EGAT. The existing business units of EGAT will be privatized and some of them will be introduced in the local stock market. The Government intends to have all new power projects (including those reserved to EGAT under the current Power Development Plan) built through competitive bidding. After its transformation, EGAT (comprising five operative units only) will not build any new power plants. All new power plants will be built, owned and operated by private groups, including the privatized business units of EGAT.

M. ELECTRICITY AND THE ENVIRONMENT

Thailand has been facing serious environmental problems resulting from rapid industrialization and economic growth. Shifting away from the growth-centred development objective, the Seventh National Economic and Social Development Plan (1991-1996) included for the first time objectives to "enhance the quality of the environment and natural resources." This resulted in a national overhaul of more than 70 laws and regulations that are related to environmental protection.

Thailand participated in the United Nations Conference on Environment and Development held at Rio de Janeiro, Brazil, in June 1992, and ratified the United Nations Framework Convention on Climate Change on 28 December 1994.

1. Air pollution from electricity generation

Electricity generation is one of the main sources of air pollution in Thailand; in 1994, it emitted about 30 per cent of the total CO_2 and 80 per cent of the total suspended particulate matters of the country. Over the period 1980-1994, emission of air pollutants from the electricity sector increased significantly in both volume an percentage of the national total. In view of the country's increasing reliance on fossil fuels, especially coal and lignite, for electricity production in the future, air pollution from the electricity sector is expected to increase sharply.

2. Environmental legislation pertaining to the electricity sector

The environmental regulation of the electricity sector in Thailand is governed mainly by the following three laws:

- National Environmental Quality Act (NEQA, 1992);
- Factory Act, 1992;
- Hazardous Substances Act, 1992.

The National Environment Quality Act of 1992 revised previous versions (the first version promulgated in 1975 and the second amended in 1978). This centrepiece environmental legislation broadened the scope of pollution control and created criminal sanctions for violations. It established the National Environment Board (NEB) chaired by the Prime Minister to centralize the responsibilities in environmental policy and planning, the prescription of environmental quality standards, recommendations to the Government for the implementation of environmental regulations, and coordination among government agencies, state enterprises and the private sector in matters concerning the promotion and conservation of environmental quality. It also established three department-level organizations under the Ministry of Science, Technology and Environment: the Office of Environmental Policy and Planning, the Department of Pollution Control, and the Department of Environmental Quality Promotion.

The Act strengthened the public's right to be informed and to participate in environmental matters, and established the NGO Coordinating Unit to facilitate this. It created the Environmental Quality Fund in the Ministry of Finance to support the implementation of the National Environmental Quality Plan. The Fund will collect service fees and penalties under virtue of the Act and receive grants and money transferred from various sources. A tax of 0.03 baht (0.12 US cents) per litre is levied on petroleum products for this Fund. The Fund will be used to provide grants and loans to private industry, government agencies, local administrations, private individuals and environmental groups for their environmental conservation activities.

The execution of NEQA 1992 is under the joint responsibility of the Prime Minister and the Minister of Science, Technology and the Environment.

The Factory Act 1992 updated the original Act enacted in 1969 which empowered the Ministry of Industry to regulate factory construction, operation, expansion and safety requirements. A power plant was classified only by the 1992 Act as a "Group 3 Factory", which requires the obtention of a permit prior to the establishment of the factory. The Act empowered the Ministry to regulate factories for the mitigation of their environmental emissions. Under this Act, it has the authority to develop standards and procedures for the control of waste, pollution and any other activity that may harm the environment as a result of factory operations. Failing to comply with this Act makes the factory subject to monetary (fine) or physical (prison) penalties.

The Hazardous Substances Act of 1992 (previously known as the Poisonous Substances Act, as introduced in 1967) also empowered the Ministry of Industry to control the import, export, manufacturing, marketing, storage, transport and use of hazardous substances. The new Act allowed a higher degree of control over the full range of hazardous substances used in the industrial process. The Act also called for inter-ministerial cooperation between the ministries of defence, agriculture, interior, public health, and science, technology and environment to supervise the activities of the Committee on Hazardous Substances. A maximum criminal penalty of $40,000 was also set up by the Act.

3. Enforcement of environmental regulations

An environmental impact study of power projects in Thailand started after the promulgation of the first National Environmental Quality Act in 1975. The 1978 amendment of NEQDA 1975 introduced the requirement of an environmental impact assessment for any large development project, regardless of its type or nature.

Since 1978, EGAT has designed a procedure of six successive phases for the environmental study of any large power project:

(1) The *environmental investigation* phase, in which a preliminary study of the proposed project for baseline information is undertaken before the feasibility phase;

(2) The comprehensive *environmental impact assessment* (EIA) phase, which includes engineering and economic studies;

(3) The *environmental impact mitigation planning* (EIMP) phase, which aims at identifying measures to improve the quality of the environment at the project site. Both the EIA and EIMP are submitted along with engineering and economic studies to the Government for project approval;

(4) The *environmental mitigation* phase, which entails the implementation of all mitigative measures during the project construction;

(5) The *environmental monitoring and development* phase, which consists of monitoring the aquatic, atmospheric and terrestrial environment. It begins before construction and continues for several years into the operation phase;

(6) The *post-environmental evaluation* phase, which is a long-term environmental campaign for the project in operation. Post-environmental evaluations are conducted for projects after their fifth year of operation. The results of these evaluations will allow EGAT to see the effectiveness of the EIA and mitigation measures used in the construction and operation of the project, and to further conclusively manage its environmental impact.

Until recently, the approval procedure of environmental studies was rather simple and straightforward. Once the project, including the study of the project's impact on the environment which is carried out by the project developers, is evaluated and approved by NESDB, it is forwarded to the Council of Ministers (Cabinet) for final approval. If the project does not give rise to public protest (transparency), it is approved, but if it does, then the project approval is delayed or shelved. Such an evaluation and approval procedure has an inherent problem with the impartiality in both assessment and approval. There was a clear need for independent studies.

Environmental impact assessment

NEQA 1992 requires an EIA to be carried out by persons or parties licensed by the Office of Environmental Policy and Planning (OEPP), for any thermal power project larger than 10 MW capacity and for any hydropower project with a reservoir volume larger than 100 million cubic metres or a storage surface area greater than 15 square kilometres.

The current regulations require the project proponent to submit a report giving details of the project concerning its type and size, location, operating procedures, safety and pollution control measures, infrastructure, and the use of locally available as well as imported resources. Most importantly, the report must give details regarding the impact of the project on the environment and residents in the close vicinity.

Power project proponents are also requested to make a detailed study of the existing environment (prior to the construction of the plant) near the site of the plant and, where possible, to estimate the economic value of all the available natural or man-made resources. A comparative study should then be made on the impact of constructing and operating the plant at that particular site estimating the magnitude of "damage" that could occur. Potential damage to the ecosystem and socio-economic well-being of local residents must be carefully studied and documented.

A detailed proposal of protection measures, including measures to protect natural plants, animal lives, as well as humans and their habitats, must be submitted.

If the EIA report is approved, all mitigation measures proposed in the report will be deemed to be conditions for operation.

Review and approval of EIA report

The review and approval process of the EIA differs, however, between a public sector (EGAT) project and a private sector project, with more actors involved in the private projects. For a large public sector project, the investment of which requires approval from NESDB and the Cabinet, the project proponent and OEPP define together the terms of reference for the EIA of the project. Once the EIA is done, the report will be reviewed by OEPP and an Expert Committee (established under the National Environmental Board) and submitted to NEB for approval. The EIA report will be submitted together with the report of the project feasibility study already approved by NESDB to the Cabinet for final decision.

For a private project, for which permission must be obtained from various authorities prior to construction or operation, the project proponent should submit the EIA report to the permitting authority and to OEPP. The permission will be withheld until the permitting authority is notified by OEPP of the results of the review of the EIA report. If OEPP finds the EIA report incomplete, it will inform the applicant within 15 days from the date of receiving the report. Otherwise, OEPP will review and make preliminary comments on the report within 30 days and the report, with the preliminary comments of OEPP, will be submitted to the Expert Committee for further consideration. The Committee has 45 days to conclude its review and consideration. Failing to respect this delay will be considered as approval. If the report is denied by the Committee, the applicant can submit a revised EIA report to the Committee, which should give the final decision within 30 days. The Committee of Experts, or its designated officials, may also inspect the project site for the purpose of review and consideration.

Complying with existing environmental regulations is a mandatory requirement stated in the request for proposals of IPP projects. However, provision is made in the power purchase agreement that if the generator is required, by change of environmental laws and regulations, to meet more stringent environmental quality standards stipulated after the signature of the agreement or subsequent to the commercial operation and commissioning, a change of price can be proposed to reflect the increased cost to meet the new environment requirement.

Incentives for companies to install pollution control devices include reduced import duties on requisite machinery and equipment, permission to bring foreign experts to Thailand as required to install, monitor or operate air or water pollution-control devices or waste water treatment facilities, and a tax exemption on income earned by such foreigners.

4. Impact of environmental regulations on power sector development

The proclamation of environmental laws and regulations in 1992 has significantly influenced power sector development in Thailand. In the long term power development plan formulated by EGAT, reduction of the environmental impact and security of long-term fuel supply have become two key factors, orienting EGAT planning towards such activities as diversification of fuel resources, expanding generation capacity by the rehabilitation of existing power plants, development of pump storage hydropower projects and joint development of energy resources with neighbouring countries.

In October 1994, EGAT announced its environmental policy for the first time, with a clear objective directed towards the effective utilization of natural energy resources and the adoption of a sustainable development approach. The environmental responsibilities committed by EGAT include:

- ❑ To enhance and protect the environmental quality related to the operation of EGAT
- ❑ To comply with or do better than all relevant environmental standards and regulations and establish appropriate performance standards where there are currently none
- ❑ To routinely review and report on environmental performance
- ❑ To promote awareness among employees, surrounding communities and other relevant groups of the need for environmental protection and of EGAT policies, programmes and achievements
- ❑ To conduct and support research towards the improvement of environmental quality related to EGAT activities

- To assess environmental risks and impacts of power projects prior to the development and before making significant changes to existing facilities and operation
- To ensure that all levels of supervisors are responsible for their operation and in compliance with environmental regulations and standards

The environmental strategy adopted by EGAT is to use more natural gas for power production and to install pollution control technologies in existing and new lignite power plants to reduce significantly sulphur dioxide (SO_2) emissions, despite their high costs. These technologies should also be applied to plants using low-sulphur (0.5 per cent) imported coal. Low-sulphur fuel oil (0.5 per cent) should be used to replace the currently used high-sulphur (3 per cent) fuel oil.

For the air quality improvement of thermal power plants, pollution control methods implemented by EGAT include the use of high stacks to limit the ground concentration of SO_2, and low NO_x burners and firing controls to reduce NO_x concentrations, and the electrostatic precipitators to reduce the particulate emissions. For the new thermal plants, the Government has ordered EGAT to install the fuel gas desulphurization (FGD) units (which can reduce SO_2, emissions by 90 per cent) in all new lignite-fired power plants, and to retrofit the existing plants.

For water quality control, the temperature of cooling water discharge is kept below 40°C in accordance with regulations issued by the Ministry of Industry. Waste water from power plants is neutralized: heavy metal is removed by chemical precipitation and organic matter by biological treatment.

EGAT now contracts licensed consultants for the EIA of its new power projects, while the preliminary study is still conducted by an in-house team. It has also scrapped some lignite-fired power stations planned in the PDP 1992-2001 because of their impossibility to meet the emission standards. The stack height of some generating units has been increased from 120 to 150 metres.

A great environmental challenge facing the electricity sector in Thailand is the management of future development under stronger environmental constraints and limited fuel choices. According to the World Bank study on Thailand's fuel options, emissions of atmospheric pollutants (SO_2, TSP and NO_x) will more than double by 2000 and increase roughly fourfold by 2010 compared with the 1990 level, if no additional pollution control technologies are applied and the environmental policy remains weak.

N. COOPERATION FOR POWER DEVELOPMENT AND POWER PURCHASE AMONG NEIGHBOURING COUNTRIES

1. Cooperation for power development in the Lao People's Democratic Republic

The Lao People's Democratic Republic has an estimated hydroelectric potential of 20,000 MW. There are many projects for which the prefeasibility studies have been conducted. At present, 195 MW has already been developed and almost all of the generated energy is transmitted to Thailand. The Lao People's Democratic Republic began selling electric power to Thailand in 1971, when the Nam Ngum hydroelectric power plant was completed. Thailand now imports 150 MW from Nam Ngum and 45 MW from Xeset hydroelectric power plants. The total imported energy from the Lao People's Democratic Republic for the year 1996 was 714 GWh.

In June 1993, the Government of Thailand and the Government of the Lao People's Democratic Republic signed a memorandum of understanding agreeing upon the development of power projects in the Lao People's Democratic Republic for the purpose of exporting electric power to Thailand, which is expected to reach a level of 1,500 MW at the end of the year 2000. It was also agreed that each party would appoint a committee to coordinate the development of the energy resources in the country, the transfer of energy and the transmission expansion in the two countries into a tangible development. In June 1996, upon the request of the Lao People's Democratic Republic, another memorandum of understanding was signed for an additional export of 1,500 MW to Thailand within 2006.

At present, there are many projects in the Lao People's Democratic Republic under feasibility study and development with the installed capacity of about 5,200 MW. Under the first 1,500 MW memorandum of understanding, only one project (Theun Hinboun, 187 MW) already has a signed power purchase agreement. For the other three projects, the electricity prices were already agreed upon for the Houay Ho project (126 MW) an Hong Sa Lignite-fired project (608 MW), and the power purchase agreements are under negotiation. The Nam Theun 2 project has been postponed.

The rest of the projects which are in the second memorandum of understanding, are under negotiation for the electricity price and PPA. These projects are:

(1)	Nam Ngum 3 project	Capacity	440 MW
(2)	Nam Ngum 2 project	Capacity	592 MW
(3)	Xe Pian-Xe Namnoy project	Capacity	460 MW

Thai-Lao People's Democratic Republic interconnection lines

EGAT has proposed the following points to receive power from the Lao People's Democratic Republic.

- Receiving point at Sakon Nakhon substation to receive the power from Theun-Hinboun project at 230 kV
- Receiving point at Ubon Ratchathani 2 substation to receive the power from Houay Ho project at 230 kV

The quantum of the purchased power at the above receiving points would be limited by the 230-kV capacity level. The major purchased power would be consumed in those areas. The following proposed receiving points would be designed to receive the power at 500 kV:

- The receiving point at Mae Moh would receive the power from Hong Sa Lignite-fired project, both phase 1 and phase 2,
- The receiving point at Nong Khai 2 substation would receive the power from Nam Ngum 2, Nam Ngum 3 and other projects in the northern part of the Lao People's Democratic Republic,
- The receiving point at Mukdahan 2 substation would receive the power from the power plant in Nam Theun basin as well as the projects in southern Lao People's Democratic Republic, such as, Xe Pian-Xe Namnoy and Xe Kaman projects.

These three 500-kV receiving points would be able to receive still more power from other projects in the future.

The Government of the Lao People's Democratic Republic has the policy to utilize the right-of-way of the transmission lines at the highest benefit. The projects developed in the same basin should transmit their generated power through the common main transmission system, which would have adequate transmission capacity. The projects developed in the Nam Ngum basin would be using the first common transmission line. A national grid company would be set up to operate the transmission network in the future.

2. Purchase of power from Malaysia

The power exchange between Thailand and Malaysia is at present at the level of 80-100 MW via the interconnection system comprising the 115/132 kV single-circuit line. The size of the interconnection is too small in relation to the size of the two systems and, as a result, the two systems cannot be operated synchronously owing to the stability problem. During the power interchange, part of the network of the power recipient will be isolated and connected to the network of the power exporter. In spite of this limitation, the interconnection still benefits both countries greatly, especially in emergency situation. The two countries, therefore, now agree to implement jointly the second stage of the Thailand-Malaysia Interconnection Project, consisting of an HVDC transmission system. The objective of the project is to increase the degree of power exchange up to 300-600 MW.

The power purchased from Malaysia will be limited to the amount which will be needed to meet the requirement in the southern region of Thailand, which accounts for about 8 per cent of the total demand. If the power in excess of the requirement of the southern region was to be imported from Malaysia to supply the load in the central region around the upper part of the Gulf of Thailand, where the electricity consumption amounts to 65-70 per cent of the national total, the investment in the transmission system would be enormous and the transmission losses too high.

3. Cooperation for power development in Myanmar

In 1990, the Government of Thailand appointed a Thailand-Myanmar Border Hydroelectric Project Committee. The Committee consists of representatives of the related agencies and is chaired by the Director-General of the Department of Energy

Development and Promotion (DEDP). The responsibility of the Committee is to follow up and coordinate with the Government of Myanmar for the development of the hydroelectric projects along the Thailand-Myanmar border.

There are eight viable projects, which consist of the Nam Mae Sai project, the Klong Kra project, the Upper and Lower Salween projects, Nam Moei 1, 2, and 3 projects, and the Mae Kok project. The overall potential of these projects is about 6,400 MW, which can generate an average of 37,000 GWh annually.

There is some progress regarding the development of two of the projects, the Klong Kra and Nam Mae Sai projects. There are two more projects under consideration which can be developed from the potential of Salween River: these are located entirely in Myanmar and are also called the Upper (4,000 MW) and the Lower (6,000 MW) Salween projects as those two projects are on the Thailand-Myanmar border. The Government of Myanmar shows an interest in developing the Lower Salween project to produce 6,000 MW of hydropower.

The possibility of the Salween project is subject to the interest of Myanmar. The Government of Myanmar once announced that it would be ready to negotiate on the Salween project after the negotiation on the purchase of natural gas from Myanmar had been completed.

4. Purchase of power from China

The purchase of electricity from the Yunnan Provincial Electric Power Corporation (YPEPC) of China is cooperation in the development of electric power between Thailand and China. The cooperation began in June 1993 by the signing of the Minute of Meeting of the two concerning agencies: EGAT and YPEPC, at Kunming City, Yunnan Province. The objective is to encourage the private sector to invest in the development of hydroelectric projects in Yunnan Province and sell the electricity to Thailand. The first two hydroelectric projects that should be the subject of feasibility studies are Jinghong and Mensong Hydropower projects. In the development of these two projects, a feasibility study of the transmission system sending the power from China to Thailand must also be carried out.

The Jinghong Hydropower project is one of the large hydroelectric projects that can be developed in the Lancang River basin. The total hydroelectric potential is about 22,240 MW. The Jinghong Hydropower project would be located on the Lancang River about 5 km upstream of Jinghong City, the capital of the Xiangshuangbanna Dai Autonomous Prefecture in the South of Yunnan Province, 700 km from Kunming City and about 300 km from Chiang Rai city in Thailand.

The project has an installed capacity of 1,500 MW (5 x 300 MW). To carry out the feasibility study of the project and its transmission interconnection facilities, YPEPC of China and MDX Power Public Co. Ltd. (MDX) of Thailand established a joint-venture company, the China-Thailand Yunnan Jinghong Hydropower Station Consulting Co. Ltd. (YJC). In August 1995, YJC contracted the Kunming Investigation Design and Research Institute (KIDRI) to carry out the project feasibility study, which would be completed in August 1997. The construction work is planned to start in 1998 with the project beginning commercial operation in 2005. Eighty per cent of the total installed capacity, or a maximum power of 1,200 MW with annual energy generation of 5.7 billion kWh, would be exported to Thailand.

Under the economic cooperation framework of the Greater Mekong subregion, the first issue concerning the line route passing through the territory of a third country was largely resolved. During the Second Electric Power Forum Meeting organized by ADB in Vientiane in December 1995, the delegation of the Lao People's Democratic Republic agreed in principle to allow the line to pass through its territory. At the same time, the delegation of China agreed that the interests of the Lao People's Democratic Republic would be taken into account in the transmission study. In the transmission interconnection study, both the 500 kV HVAC and ±500 kV HVDC are being considered.

In March 1996, the Director of the Yunnan Provincial Electric Power Bureau (YPEPB) and the Governor of EGAT discussed the hydropower export from Yunnan to Thailand. The main issues discussed during the meeting are summarized as follows:

(1) YPEPB is willing to develop the Jinghong Hydropower project and proposes to export part of the power generated by such project to Thailand;

(2) EGAT has agreed to participate in the feasibility study of the transmission interconnection between Jinghong and Thailand;

(3) EGAT will consider purchasing the power from the project if the project is economically viable as well as technically feasible to EGAT, and also provided that the project fits in with the requirements and criteria of the EGAT Power Development Plan.

O. DEMAND-SIDE MANAGEMENT

With a clear understanding of the advantages of electricity conservation in terms of reducing the capital cost for investment, efficiently utilizing energy resources, improved energy security, and benefit to the environment, the National Energy Policy Council (NEPC), in September 1990, requested, that the three electric utilities make a master plan for DSM. In order to do so, EGAT, as the lead agency, requested assistance from the World Bank in preparing the terms of reference; these were considered and modified by the three electric utilities, and a DSM Committee and Working Group were formed.

In the meantime, the Canadian International Development Agency (CIDA) technical assistance project to NEPO had included an activity on DSM in the electric power sector. MONENCO, a Canadian consultant firm, reviewed the potential for DSM in Thailand and developed recommendations for implementing that.

NEPC also requested EGAT to consider DSM in the power system planning process. In January 1991, EGAT accepted the proposal of the International Institute for Energy Conservation (IIEC) to provide EGAT with some technical assistance in the development of integrated resources planning and DSM in Thailand, with financial support from the United States Environmental Protection Agency (EPA) and the United States Agency for International Development (USAID). A report, *Demand Side Management Master Plan for Thailand's Electric Power System,* prepared by IIEC in August 1991, was reviewed by the three utilities and approved by NEPC in November 1991. In December 1991, the Government entrusted EGAT with the responsibility for carrying out the implementation of the DSM with the close cooperation and assistance of MEA and PEA.

The approved DSM master plan proposed four action plans to be implemented within five years:

- DSM Action Plan 1 is on load management, which includes the direct load control project and thermal energy storage project. It aims at reducing the peak load
- DSM Action Plan 2 is the energy savings plan for the commercial sector, which will focus on the use of high-efficiency lighting and air-conditioning systems and incorporate the best efficiency or energy savings measures into the design of new buildings
- DSM Action Plan 3 is the energy savings plan for the industrial sector, which will focus on the use of high-efficiency motors
- DSM Action Plan 4 is the energy savings plan for the residential sector: the largest savings will come mainly from the use of high-efficiency home appliances, especially refrigerators and air-conditioners, as well as high-efficiency fluorescent tubes and ballasts

The objectives of the five-year DSM Plan (1992-1996) were set as follows:

- To develop a set of DSM pilot programmes to show the potential for DSM as an energy resource
- To build the organizational capacity of the utilities to deliver full-scale DSM programmes
- To save a peak demand of 238 MW and an amount of 1,427 GWh/year from the fifth year onwards, with a total investment of $189 million (4,800 million baht).

Over the past two years of experience in implementation, the Master Plan was unofficially modified, by varying some operational strategies to coincide with the typical behaviour and culture of Thai people. It is expected that at the end of 1998, estimated technical potential will yield savings of 1,400 MW demand, or approximately 700 MW peak demand (using a 50 per cent coincidence factor) and 3,400 GWh energy, using the same budget amount, 4,800 million baht.

The status of the DSM programmes can be reported as follows:

1. Programme fully implemented

(1) Energy-efficient fluorescent lamp programme. The manufacturers were persuaded to

switch production from 20 W and 40 W fluorescent tubes (fat tube) to 18 W and 36 W (thin tube) instead. The programme was expected to reduce 50 and 159 MW peak demand, 215 and 1,528 GWh energy by the end of 1995 and 1998 respectively.

2. Programmes under implementation

Energy-efficient refrigerator programme

Energy-efficient air-conditioner programme

Green building programme

Lighting retrofit programme in the Royal Project Foundation

"Million Hearts Million Lights" programme

Thermal energy storage system

High-Efficient motor programme

Attitude-creation programme

Monitoring and evaluation programme

3. Programmes under preparation

Street lights programme

Energy-efficient ballast programme

Low-income fluorescent programme

Energy Service Company (ESCO) programme

4. Future programmes

Energy-efficient freezer programme

Low-efficiency equipment buy-back programme

P. 1994 POWER PURCHASE SOLICITATION

In response to the policy of the Government, EGAT has launched an IPP programme to allow the private sector to construct and operate large-scale power projects (base-load plant) and sell electricity to EGAT. The first solicitation was issued on 15 December 1994 for the power purchase of 3,800 MW with a first stage of 1,000 MW, expected for commercial operation within 2000, and a second stage of 2,800 MW in 2001-2002.

In April 1995, a supplementary notice was announced for an additional capacity of 300 MW to be purchased. At the closing date of bid submission on 30 June 1995, 104 registered bidders who had formed into 32 consortia submitted 50 proposals with a total proposed power capacity of 39,064 MW.

The diversification of fuel utilization in the proposals was as follows:

–	Natural gas and LNG	24 224 MW (37 plants)
–	Coal	13 487 MW (12 plants)
–	Orimulsion	1 353 MW (1 plant)

Therefore, there is competition among the different types of fuel.

In the evaluation, the following main issues would be covered:

1. Characteristics of the proposed projects

- ❑ To be operated as base-load power plants.
- ❑ The generating capacity at any site must not be more than that specified in the request for proposal for the first 1,000 MW and not bigger than 700 MW for each single unit for another 2,800 MW.
- ❑ Location of power plants, selected by EGAT, with preferable sites in the central region, and western and eastern coasts. For the first 1,000 MW, the preferable sites are the location in which the power plants can be built without upgrading the existing system owing to time constraints. For the next 2,800 MW, the sites will be in the western area (for 1,400 MW) and in the eastern area for another 1,400 MW.
- ❑ The fuel sources must be environmentally clean, acceptable to the public, with stable price and assured supplies, and support the national policy of fuel diversification. The choice of fuel includes LNG, hydrocarbon gas and its associated liquid, coal and orimulsion.

2. The EIA report must be prepared by IPP.

3. IPP will be responsible for applying for the project construction and operation permits.

4. IPP will build, own and operate the power plant and also provide the fuel for power generation.

5. Investors evaluation, selection and notification of bidding award will be undertaken by the Evaluation Subcommittee appointed by the Government.

IPP proposals are evaluated by the Evaluation Subcommittee which comprises the Governor of EGAT and representatives of the National Energy Policy Office (NEPO), the National Economic and Social Development Board (NESDB), and the Fiscal Policy Office (FPO). Final approval will be given by the Board of Directors of EGAT.

The evaluation criteria are as set forth in the request for proposals: 60 per cent weight on price factors and 40 per cent weight on non-price factors.

- Price factors-60 per cent – for availability payment, energy payment and connection cost.
- Non-price factors-40 per cent:
  - For viability of project (level of development 11 per cent + financial status of bidder and ability to arrange finance 7 per cent, + experience 7 per cent)
  - Fuel and fuel diversity-4 per cent
  - Other factors (location 6 per cent + Exception to model PPA 5 per cent)

The evaluation was commenced in July 1995. Stage I was completed in February 1996 with the disclosing of 13 proposals, 3 in the Western Corridor and 10 in the Eastern Corridor.

Stage II was completed in April 1996, with the disclosing of eight proposals, four with coal, 1 with orimulsion and 3 with gas.

The negotiations were initiated with the successive top-ranked proposals in each stage since April 1996, so that all targets will be accomplished and the signing of the power purchase agreement can be performed in September 1996 for Stage I and in December 1996 for Stage II.

Brief summaries of the successive proposals are shown in tables XX.2 and XX.3.

One of the most serious issues in the first IPP solicitation was the clarity of the fuel supply, especially the commitment of gas supply and gas prices.

Since the right fuel mix in the power generation is one of the national policy concerns, the EGAT Power Development Plan will take into account the impact of the power purchase from IPP and SPP together with the fuel diversity in order to specify the right requirement of the additional capacity.

In the latest generation requirement forecast by the Thailand Load Forecast Subcommittee (April 1996), the annual increases in the power generation are tremendous, from 1,521 MW to 1,761 MW in 1996 and 2003. Therefore, an additional 1,600 MW would be purchased from this first solicitation.

Table XX.2 Successive top-ranked proposals qualified for IPP Stage I

Rank	*Bidder's name*	*Capacity (MW)*	*Substation specified in RFP*
Projects in the Eastern Corridor			
1.	Consortium of Thai Oil Co. Ltd./Unocal International Corp./Westinghouse Electric Corp.	700	Ao Phai
2.	TUNA Power Co. Ltd.	636	Ao Phai
3.	TDF Power Co. Ltd.	300	Bo Win
4.	Consortium of Union Energy Co. Ltd./British Gas PLC	642	Ao Phai
5.	Eastern Power Electric Co. Ltd. – Gateway	643	Prachinburi
6.	Consortium of STC Capital Holding Co. Ltd./Mitsubishi Corp.	638	Ao Phai
7.	Cogeneration Co. Ltd.	200	Rayong
8.	Eastern Power – Bangbo	300	Bang Bo
9.	Tawan ABB	300	Klong Mai
10.	Bangkok Energy System A Ltd.	300	Klong Mai
Projects in the Western Corridor			
1.	Tri Energy Co. Ltd.	600	Ratchaburi
2.	Bangkok Energy System B Ltd.	326	Ratchaburi
3.	National Electric Co. Ltd.	600	Ratchaburi

Table XX.3 Successive top-ranked proposals qualified for IPP Stage II

Rank	*Bidder's name*	*Capacity (MW)*	*Fuel*	*Location*
1.	Union Energy – Tomen – IVO Consortium	1 400	Coal	Hin Krut (Prachuap Khiri Khan)
2.	Gulf Electric Co. Ltd. and MEC International B.V.	700	Coal	Kui buri (Prachuap Khiri Khan)
3.	BLCP Power Limited	1 400	Coal	Map Tha Phut (Rayong)
4.	BW II Power Limited	673	Gas	Bo Win (Chonburi)
5.	JV. of Tomen Corp., Premier Enterprise, CEA International, Sino-Thai Eng.	684	Gas	Hua Pong (Rayong)
6.	LPM Consortium	1 353	Orimulsion	Kui buri (Prachuap Khiri Khan)
7.	Ratchaburi Power Generation Consortium	640	Gas	Wat Ban Song (Ratchaburi)
8.	Sahaviriya Electric	1 400	Coal	Bang Sapan (Prachuap Khiri Khan)

It is planned to announce the second request for proposal in 1998. There may be some differences and improvements in terms of more specific types of power plants and fuel, and also the amount of megawatts required by each type of fuel.

1. IPP proposal evaluation and negotiation

Two top-ranked Stage I bidders, Consortium of Thai Oil/Unocal/Westinghouse and Tri Energy Co. Ltd., were invited for negotiations on the power purchase agreement (PPA) in April 1996. The major issues which are discussed involve the balancing of investors' needs, EGAT and the Government of Thailand's concerns on the security of power supply, and the provision of incentives for all prospective successful bidders to perform their obligations in compliance with this agreement throughout the contract term.

According to the PPA, there are also provisions to decrease the payments for the availability as a result of loss in IPP power generation reliability. On the other hand, EGAT provides payments to lenders if it is EGAT default or should there be unforeseen government interference. It was expected to conclude the PPA negotiations with Consortium of Thai Oil/Unocal/Westinghouse and Tri Energy Co. Ltd. in September and November 1996 respectively.

As regards to the Stage II proposals, the four top-ranked bidders on the short list were invited for PPA negotiations in May 1996. At the first meeting with the four parties, EGAT also asked them to confirm their tariff structures as well as their proposed alternative PPA (if any) by early June 1996.

Two negotiations with Stage II bidders had been planned. The first negotiation was scheduled for August 1996. Subsequently, EGAT would revise and update the PPA to reflect the results of the first discussion before sending it to the bidders for their consideration. The second negotiation was scheduled from the end of September to the end of October 1996. The conclusions of PPA negotiations with these four Stage II bidders would be submitted to the Evaluation and Selection of Proposals for Power Purchases from IPPs Committee for consideration and decision, so that the award of the Agreement to the successful bidders of 2,800 MW capacity could be made.

However, to accommodate the new demand forecast in the short term up to 2003, EGAT has already been granted a consent by NEPC to increase its power purchase from IPP projects of its 1994 solicitation by 1,600 MW in addition to the 4,100 MW, as follows:

Year	*Additional power to be purchased (MW)*	*Remarks*
2000	300	From Stage I shortlisted bidder on the western corridor
2001	700	From Stage II shortlisted bidders
2003	600	From Stage II shortlisted bidders

With the additional power purchase of 300 MW from Stage I bidders, EGAT has already extended an invitation for the second-ranked in the short list on the western corridor to begin the negotiation on the power purchase agreement in August 1996, whereas the negotiation for the additional power purchase of 1,300 MW from Stage II bidders had been set to take place at the very beginning of 1997.

2. Summary of Common negotiated issues

- ❑ Gas sales agreement
- ❑ Payments in case of *force majeure* and governmental *force majeure* events affecting both parties
- ❑ Events of defaults and both parties' obligations towards the events
- ❑ Termination right of each party and buy-out-price
- ❑ Tariff reduction
- ❑ Change-in-law adjustment
- ❑ Environment quality requirement in relation to change-in-law provision
- ❑ Additional security
- ❑ Incentives and penalities for operation performance
- ❑ Construction of new transmission facilities

3. Successful bidders

For Stage I

On 13 February 1997, the power purchase agreement between EGAT and the Independent Power (Thailand) Company Limited (IPT) – the Consortium of Thai Oil/Unocal/Westinghouse – was signed. The agreement would be effective on 21 March 1997. The PPA of the Tri Energy Company Limited (TECO) is under consideration.

For Stage II

The PPAs for the Consortium of Union Energy/ Tomen/IVO, Gulf Power Generation Company Limited, BLCP Power Limited and Bo Win II Power Company Limited are still under negotiation.

The commissioning schedules for all these IPPs are shown in the list of projects for the recommended plan.

Figure XX.11 EGAT daily load curves on peak day (fiscal years 1988-1997)

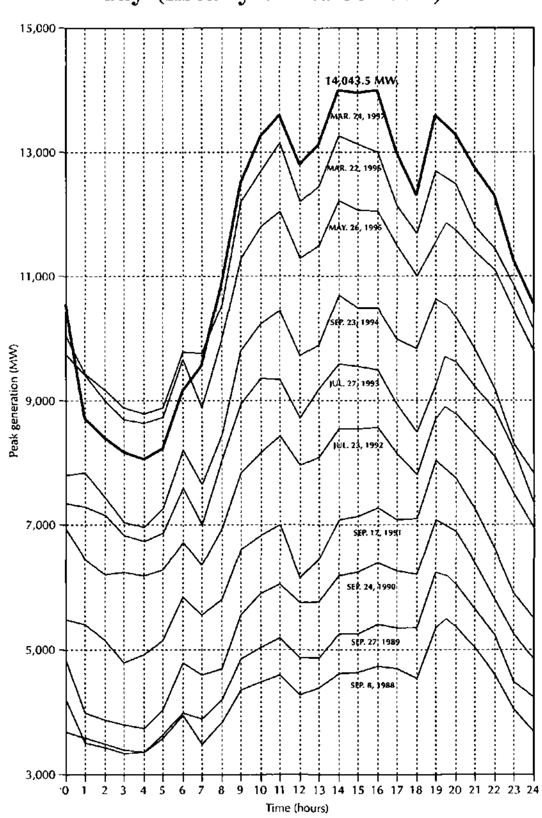


Table XX.4 Total EGAT generation requirement

Fiscal year	*Peak generation*			*Energy generation*			*Load factor*
	MW	*Increase*		*GWh*	*Increase*		
		MW	*%*		*GWh*	*%*	*%*
			Actual				
1986	4 180.90	302.50	7.80	24 779.53	1 422.96	6.09	67.66
1987	4 733.90	553.00	13.23	28 193.16	3 413.63	13.78	67.99
1988	5 444.00	710.10	15.00	31 996.94	3 803.78	13.49	67.09
1989	6 232.70	788.70	14.49	36 457.09	4 460.16	13.94	66.77
1990	7 093.70	861.00	13.81	43 188.79	6 731.69	18.46	69.50
1991	8 045.00	951.30	13.41	49 225.03	6 036.25	13.98	69.85
1992	8 876.90	831.90	10.34	56 006.44	6 781.41	13.78	72.02
1993	9 730.00	853.10	9.61	62 179.73	6 173.29	11.02	72.95
1994	10 708.80	978.80	10.06	69 651.14	7 471.41	12.02	74.25
1995	12 267.90	1 559.10	14.56	78 880.37	9 229.23	13.25	73.40
1996	13 310.90	1 043.00	8.50	85 924.13	7 043.77	8.93	73.69
Average growth 1987-1996	–	913.00	12.28	–	6 114.46	13.24	–
			Forecast				
1997	14 904.00	1 593.10	11.97	97 716.00	11 791.87	13.72	74.84
1998	16 445.00	1 541.00	10.34	108 234.00	10 518.00	10.76	75.13
1999	18 010.00	1 565.00	9.52	118 797.00	10 563.00	9.76	75.30
2000	19 658.00	1 648.00	9.15	129 601.00	10 804.00	9.09	75.26
2001	21 423.00	1 765.00	8.98	141 598.00	11 997.00	9.26	75.45
2002	23 131.00	1 708.00	7.97	153 141.00	11 543.00	8.15	75.58
2003	24 848.00	1 717.00	7.42	165 460.00	12 319.00	8.04	76.01
2004	26 645.00	1 797.00	7.23	179 206.00	13 746.00	8.31	76.78
2005	28 518.00	1 873.00	7.03	193 097.00	13 891.00	7.75	77.30
2006	30 464.00	1 946.00	6.82	206 566.00	13 469.00	6.98	77.40
2007	32 536.00	2 072.00	6.80	221 170.00	14 604.00	7.07	77.60
2008	34 692.00	2 156.00	6.63	236 964.00	15 794.00	7.14	77.97
2009	36 914.00	2 222.00	6.40	251 909.00	14 945.00	6.31	77.90
2010	39 247.00	2 333.00	6.32	267 557.00	15 648.00	6.21	77.82
2011	41 683.00	2 436.00	6.21	283 858.00	16 301.00	6.09	77.74
Average growth							
1982-1986	–	318.44	10.06	–	1 763.91	9.20	–
1987-1991	–	772.82	13.99	–	4 889.10	14.71	–
1992-1996	–	1 053.18	10.60	–	7 339.82	11.79	–
1997-2001	–	1 622.42	9.99	–	11 134.77	10.51	–
2002-2006	–	1 808.20	7.30	–	12 993.60	7.85	–
2007-2011	–	2 243.80	6.47	–	15 458.40	6.56	–

Source: Thailand Load Forecast Subcommittee, October 1996.

Table XX.5 Existing installed generating capacity
(as of March 1997)

Plant type		*Number of units*	*Capacity (MW) installed*	*Average energy capability (GWh/yr)*
A. Hydroelectric plant				
Bhumibol		8	724.900	1 062
Sirikit		4	500.000	670
Ubolratana		3	25.200	26
Sirindhorn		3	36.000	52
Chulabhorn		2	40.000	59
Kang Kracharn		1	17.500	57
Nam Pung		2	6.000	10
Srinagarind		5	720.000	983
Bang Lang		3	72.000	119
Tha Thung Na		2	38.000	94
Khao Laem		3	300.000	460
Pak Mun		4	136.000	251
Huai Kum		1	1.060	0
Ban Santi		1	1.275	0
Mae Ngat		2	9.000	19
Rajjaprabha		3	240.000	351
Miscellaneous		7	0.429	12
	Total	54	2 867.364	4 225
B. Thermal power plant				
North Bangkok		3	237.500	1 250
South Bangkok		5	1 330.000	9 320
Mae Moh		13	2 625.000	18 396
Surat Thani		1	25.000	170
Bang Pakong		4	2 300.000	16 118
	Total	26	6 517.500	45 254
C. Combined cycle power plant				
Bang Pakong	– Blocks 1 & 2	10	760.600	5 330
	– Blocks 3 & 4	6	614.000	4 303
Nam Phong	– Blocks 1 & 2	6	710.000	4 976
South Bangkok	– Block 1	3	335.000	2 348
	– Block 2 (Gt)	2	404.000	2 832
Wang Noi	– Block 1 (Gt)	2	446.000	3 126
	– Block 2 (Gt)	2	446.000	3 126
	Total	31	3 715.600	26 041
D. Gas turbine power plant				
Lan Krabu		8	140.000	980
Nong Chok 1-4		4	488.000	1 070
Sai Noi 1-2		2	244.000	534
	Total	14	872.000	2 584
E. Purchased power				
Khiridharn Hydro		2	12.700	22
EGCO				
Rayong CC	– Blocks 1-4	12	1 232.000	8 634
Khanom Thermal		2	150.000	1 050
Khanom CC		5	674.000	4 723
SPP (COCO)		2	180.000	1 261
SPP (TUNTEX)		1	12.000	84
	Total	24	2 260.700	15 774
	Total	**149**	**16 233.164**[a]	**93 878**

[a] Excluding diesel plants of 16.6 MW and alternative energy 0.534 MW.

Table XX.6 List of projects for recommended plan

Power plants	Fuel type	Number of units	Unit capacity (MW)	Total (MW)	Commissioning schedule
Projects Under Construction					
Wang Noi CC1 (St)	–	1	205	205	April 1997
South Bangkok CC2 (St)	–	1	219	219	June 1997
Wang Noi CC3 (Gt)	Gas	1-2	200	400	July 1997 – August 1997
Wang Noi CC2 (St)	–	1	205	205	August 1997
Wang Noi CC3 (St)	–	1	200	200	March 1998
Theun Hinboun (Lao People's Democratic Republic)	Hydro	1	187	187	April 1998
Ratchaburi CC1 (Gt)	Gas	1-2	200	400	Sep. 1998 – Oct. 1998
Ratchaburi CC2 (Gt)	Gas	1-2	200	400	Nov. 1998 – Dec. 1998
Ratchaburi CC3 (Gt)	Gas	1-2	200	400	Jan. 1999 – Feb. 1999
BB # 5 Renovation (from 70 to 75 MW)	Hydro	5	5	5	February 1999
EGAT-TNB	–	–	300	300	March 1999
IPP (Thai Oil Co., Ao Phai)	Gas	1	700	700	July 1999
Ratchaburi CC1 (St)	–	1	200	200	September 1999
Ratchaburi Thermal	Oil/Gas	1	700	700	September 1999
BB # 6 Renovation (from 70 to 75 MW)	Hydro	6	5	5	September 1999
Ratchaburi CC2 (St)	–	1	200	200	November 1999
Ratchaburi CC3 (St)	–	1	200	200	January 2000
Ratchaburi Thermal	Oil/Gas	2	700	700	January 2000
Lam Takhong Pumped Storage	Hydro	1-2	250	500	Feb. 2000 – May 2000
IPP (Tri Energy Co., Ratchaburi)	Gas	1	700	700	May 2000
IPP (Addition)	Gas	1	300	300	September 2000
Ratchaburi Thermal	Oil/Gas	3	700	700	January 2001
IPP (Union Energy-Tomen-IVO, Prachuap)	Coal	1-2	700	1 400	April 2001 – July 2001
IPP (BW II Power Co., Chonburi)	Gas	1	673	673	April 2001
IPP (Gulf Electric Co., Prachuap)	Coal	1-2	350	700	April 2001 – Oct. 2001
Ratchaburi Thermal	Oil/Gas	4	700	700	January 2002
IPP (BLCP Power Co., Rayong)	Coal	1-2	670.5	1 341	Oct. 2002 – Feb. 2003
Lam Takhong Pumped Storage	Hydro	3-4	250	500	Jan. 2003 – Apr. 2003
Houay Ho (Lao People's Democratic Republic)	Hydro	–	126	126	September 1999
Krabi Thermal	Oil/Gas	1	300	300	January 2000
Krabi Thermal	Oil/Gas	2	300	300	March 2001
Hong Sa (Lao People's Democratic Republic)	Lignite	1	304	304	December 2001
Hong Sa (Lao People's Democratic Republic)	Lignite	2	304	304	June 2002
Purchase from Lao People's Democratic Republic (2) # 1	–	–	700	700	December 2002
Surat Thani CC1	Gas	1	300	300	April 2003
Purchase from Lao People's Democratic Republic (1)	–	–	600	600	March 2004
Purchase from Lao People's Democratic Republic (2) # 2	–	–	800	800	March 2004
Khiritharn Pumped Storage	Hydro	1-3	220	660	January 2005
IPP	–	–	1 000	1 000	March 2005
IPP (South)	–	–	300	300	March 2005

Table XX.6 *(continued)*

Power plants	*Fuel type*	*Number of units*	*Unit capacity (MW)*	*Total (MW)*	*Commissioning schedule*	
Thap Sakae	Coal/Gas	1	1 000	1 000	October	2005
IPP	–	–	1 000	1 000	March	2006
Thap Sakae	Coal/Gas	2	1 000	1 000	March	2006
IPP	–	–	1 000	1 000	October	2006
IPP (South)	–	–	300	300	February	2007
IPP	–	–	1 000	1 000	March	2007
Chulabhorn Pumped Storage	Hydro	1-2	200	400	March	2007
IPP	–	–	1 000	1 000	October	2007
IPP	–	–	600	600	February	2008
IPP (Peaking)	–	–	200	200	February	2008
Chulabhorn Pumped Storage	Hydro	3-4	200	400	March	2008
IPP	–	–	1 000	1 000	March	2008
IPP (South)	–	–	300	300	May	2008
IPP	–	–	1 000	1 000	January	2009
IPP	–	1-2	1 000	2 000	March	2009
IPP	–	–	1 000	1 000	January	2010
IPP (South)	–	–	300	300	February	2010
IPP	–	–	1 000	1 000	March	2010
IPP	–	–	600	600	March	2010
IPP (Peaking)	–	–	200	400	April	2010
IPP	–	–	1 000	1 000	January	2011
IPP (Peaking)	–	–	200	400	February	2011
IPP	–	–	1 000	1 000	March	2011
IPP (South)	–	–	300	300	March	2011
	Existing capacity by September 1996			16 141.5	MW	
	Total added capacity (up to 2011)			37 034.0	MW	
	Plants retirement			2 578.1	MW	
	Total capacity at end of 2011			50 597.4	MW	
	Purchase from SPP			2 310.0	MW	
	Grand total capacity at end of 2011			52 907.4	MW	

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