# SRI LANKA'S POWER SECTOR: PRIVATIZATION ISSUES

by

Sanjay Kalpage

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Signature of Author ..........................................
d Computer Science, May, 1996

Certified by ..........................................
Richard D. Tabors, Ph.D., Senior Lecturer, Technology, Management and Policy
Thesis Advisor

Certified by ..........................................
Richard de Neufville, Ph.D., Professor of Civil and Environmental Engineering
Chairman, Technology and Policy Program

Accepted by ..........................................
Graduate Students

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## ABSTRACT

Sri Lanka's economy began developing rapidly after the introduction an open economic policy in 1977. The country's growth rate of around 6 percent has been accompanied by a even higher growth in demand for electricity of 8 percent. It is crucial that the government carefully plans to meet this demand, because the provision of necessary infrastructure (power in particular) is vital for the country's continued economic progress. Government budgetary difficulties, combined with scarcity of funds available through international lending agencies, has made raising the US$ 1100 million required for investment in new power generating capacity before the year 2000, a monumental task for Sri Lanka's policy makers.

The means used to finance required investments in power generation will depend on the future organization and ownership of the power sector. If the government continues to own and operate the sector it may be forced to obtain the required funds directly from international capital markets. Alternatively, Sri Lanka could turn to the private sector for infrastructure provision. Currently, its government is considering schemes such as Build Operate Transfer (BOT), which have been introduced in rapidly growing countries in the Asian region. The eventual reversion of the assets to state control in these models for privatization increase their political feasibility. The complex risk relationships between government, lenders, investors, and contractors form the crux all BOT projects, and the state must incorporate them into a workable formula that satisfies all involved parties.

I examined the viability of several projects that can be built and financed using the BOT method (diesel 40 MW, hydro 70 MW, and coal 300 MW) from the investors' perspective. The crucial figure associated with each viable project is the "selling price" or the price at which the state would have to purchase the privately generated electricity; this value should be compared with 2.89 Rs./kWh—the long-term average price calculated by the Ceylon Electricity Board (CEB) for its own 20-year generation plan. At a discount rate of 15% only the diesel plants are viable at a selling prices of around 3.50-4.00 Rs./kWh. The hydro and coal plants are not viable at even 5.00 Rs./kWh.

Therefore, my analysis suggests that for private generation by the BOT method to be viable in Sri Lanka, the government should either be prepared to pay vastly increased prices for electricity, or take active measures to reduce the required ROE for projects in the country. Since the former strategy alone would adversely affect the economy, because electricity is a vital input in most forms of production, and rapid increases in its price will contribute to domestic inflation, the state should actively pursue the latter. As the required ROE for a project is directly tied its riskiness, the government should implement measures to mitigate the financial, political, and technical risks associated with doing business in Sri Lanka. An important first step is to bring peace and stability to the country, because the current high levels of domestic government borrowing (to finance its defense expenditure) have pushed up interest rates. The ROE is usually set at 10 percentage points above the prime lending rate; therefore, reducing interest rates will lower required ROEs. The government should also institute a comprehensive legal and regulatory framework in order to increase investor confidence in the country, thus reducing the required ROE for domestic projects.

A reliable and adequate supply of electricity is an important requirement for making Sri Lanka attractive to potential investors in other sectors of its economy. It is crucial, therefore, that the country develops a flexible, realistic generation expansion plan which will meet future requirements, while securing the capital necessary to implement it.


**Thesis Advisor:** Richard D. Tabors, Ph.D., Senior Lecturer, Technology, Management and Policy

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*for their continued interest, encouragement, support, and inspiration throughout my education*

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# List of Abbreviations

| | |
|---|---|
| ADB | Asian Development Bank |
| ADR | American Depository Receipt |
| AFBC | Atmospheric fluidized bed combustion |
| AMP | Accelerated Mahaweli Program |
| BATAN | Badan Tenaga Atom Nasional (The Philppine National Atomic Energy Board) |
| BoI | Board of Investment |
| BOO | Build-Own-Operate |
| BOOT | Build-Own-Operate-Transfer |
| BOT | Build-Operate-Transfer |
| BLT | Build-Lease-Transfer |
| Bt. | Baht (Thai currency) |
| BTO | Build-Transfer-Operate |
| CEB | Ceylon Electricity Board |
| CPC | Ceylon Petroleum Corporation |
| CTC | Compania de Telefonos de Chile |
| D. | Dong (Vietnamese currency) |
| DBFO | Design-Build-Finance-Operate |
| DES | Department of Electricity Supply (Malaysia) |
| DGEU | Department of Government Electrical Undertakings |
| EBRD | European Bank for Reconstruction and Development |
| ECO | Extended Co-financing Facility |
| ECT | Energy Coordinating Team |
| EGAT | Electricity Generating Authority of Thailand |
| EGCO | Electricity Generating Public Company (Thailand) |
| EIU | Economist Intelligence Unit |
| FAO | Food and Agriculture Organization |
| FD | Forest Department |
| GDP | Gross Domestic Product |
| GECC | General Electric Capital Corporation |
| GWh | Giga Watt Hours |
| IBRD | International Bank for Reconstruction and Development (World Bank) |

| | |
|---|---|
| IDA | International Development Authority |
| IEA | International Energy Agency |
| IGCC | Integrated Gasification Combined Cycle |
| IIFC | Infrastructure Investment Fund Company |
| IPP | Independent Power Producers |
| KEPCO | Korea Electric Power Co. |
| kW | Kilowatt |
| kWh | Kilo Watt Hours |
| LECO | Lanka Electric Company |
| LOLP | Loss of Load Probability |
| LPG | Liquefied Petroleum Gas |
| LROT | Lease-Renovate-Operate-Transfer |
| MIGA | Multilateral Investment Guarantee Agency |
| MW | Mega Watts |
| NARESA | Natural Resources, Energy and Science Authority |
| NEB | National Electricity Board (Malaysia) |
| NEDCAP | National Energy Demand and Conservation Program |
| NERSE | New, Renewable and Rural Sources of Energy (Task Force) |
| NFCP | National Fuelwood Conservation Program |
| NES | National Energy Strategy |
| P. | Peso (Philippino currency) |
| PA | People's Alliance |
| PERC | Public Enterprise Reform Commission |
| PLN | Perusahaan Umum Listrik Negara (the State Owned electricity company in the Philippines) |
| PPA | Power Puchase Agreement |
| R&D | Research and Development |
| RM | Ringgit Malaysia (Malaysian currency) |
| Rmb | Renminbi (Chinese currency) |
| Rp. | Rupiah (Indonesian currency) |
| Rs. | Rupees (Indian or Sri Lankan currency) |
| toe | Tons of Oil Equivalent |
| T&D | Transmission and Distribution |
| TNB | Tenaga Nasional Berhad (One of three Malaysian power utilities) |
| TPES | Total Primary Energy Supply |

| | |
|---|---|
| UDA | Urban Development Authority |
| UNDP | United Nations Development Programme |
| UK | United Kingdom |
| UNP | United National Party |
| USAID | United States Agency for International Development |
| US$ | United States Dollars |
| Y | Yuan (Chinese currency) |

# INTRODUCTION

The governments of the newly developing nations in Asia are faced with a formidable challenge—how to construct and finance crucial infrastructure at a pace which will meet rapidly growing demand. In many Asian cities, there is evidence of their partial failure to meet this challenge. With auto use increasing at a frenzied pace, capital cities from Beijing to Bangkok are paralyzed by traffic jams. Airports are overwhelmed by long lines of travelers. Energy needs are growing exponentially, and the demand for mobile phones, faxes, and new television services are severely taxing existing telecommunications infrastructure. It is evident that if these vital infrastructure needs are not met quickly, the entire development process in these countries will be jeopardized.

Electricity, as an especially high grade of energy, plays an important role in economic development. Its correlation with economic growth is illustrated by the fact that between 1970 and 1980, gross domestic product (GDP) in developing countries grew at 5.5 percent per year, while their electricity consumption increased at an annual rate of over 7 percent. Therefore, many Asian nations have been grappling with the problem of supplying a rapidly growing demand for power.

Sri Lanka, a small Asian nation, is faced with this common problem. Its government has been forced to address this issue immediately, because of the widespread public dismay regarding the recent power cuts which were instituted in April 1996 because of the delayed arrival of the seasonal monsoon rains (the country generates 80% of its electricity by hydro stations). Among the many options being considered, the partial privatization of the generating sector has been given much attention, partly because the government already faces a substantial budget deficit (and therefore lacks the funds to build the needed generating capacity). In this thesis

I will look at the problems in the Sri Lankan power sector within the context of the general situation of this sector in other countries in the region, and explore possible measures to alleviate these problems. I have concentrated mainly on how the state will fund the needed power generation infrastructure, and have not addressed several other measures that can be taken to reduce power needs or to generate power more efficiently, because even if such methods are used widely, a substantial amount of generating capacity will still have to be added to the national grid to meet the rapidly growing power needs of the country. However, in order to give the reader an idea of some approaches that are being considered, I have presented a few of these other measures in Appendix 5.

Chapter 1 looks at the importance of infrastructure in the development process, and explore the changing role of government in its provision. I will also address the current trend of privatizing many infrastructure sectors, and then look at the more specific case of how this action may apply to the current power crisis in the developing world.

In Chapter 2, I will give an overview of Sri Lanka in order to establish the political, social and economic context in which policy makers in the power sector have to operate. This backdrop will enable the reader to evaluate the feasibility of specific policies proposed by international development agencies such as the World Bank and USAID. In the second part of the chapter, I will give a brief overview of Sri Lanka's energy sector, so as to illustrate how electric power fits into the overall energy framework of the country.

In Chapter 3, I will give an overview of the current state of the present power generating system and describe some of its main characteristics. I will also present the long term generation plan of the Ceylon Electricity Board—the body involved in planning for future generation. This foundation will enable me to estimate the investment needed for additional generating capacity scheduled to be constructed up to the year 2000.

I will explore possible ways in which the government can finance the above required investments in the power sector in Chapter 4. I will then discuss the possible consequences of the two main options—retaining state control of the sector, or privatizing portions of it. For the latter scenario, I will specifically discuss the modes of private sector participation, the pros and cons of privatization, variants of the privatized approach, and risk allocation issues.

In Chapter 5, I will discuss the Build, Operate Transfer (BOT) method of privatization—the approach which has gained most attention in the Asian region. Topics I will address include contractual agreements, the required legal framework, risks and their mitigation, and measures of project viability. I will then examine the feasibility of this scheme's use to the Sri Lankan power sector. For this purpose I have constructed spread sheet models of the cash flows of three proposed additions to the country's grid—a 40 MW diesel plant, a 70 MW hydro plant, and a 300 MW coal plant, and have determined the effect of the discount rate, the selling price of electricity, and the proportion of equity disbursement on performance indicators such as return on equity (ROE) and debt service coverage ratio (DSCR).

Chapter 6 presents some recommendations to the Sri Lanka. Here, I have discussed the barriers to private sector participation in Sri Lanka, the need to balance costs and benefits of private power generation, current government efforts to facilitate foreign investment, and further steps required to encourage private generation.

In the final "conclusions" chapter, I highlight the main findings of my thesis, and briefly discuss Sri Lanka's outlook for the concluding decade of the century.

# CHAPTER 1

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## Infrastructure: Its Importance and Provision

Infrastructure services, which include power, transport, telecommunications, provision of water and sanitation, and safe disposal of wastes, are central to economic production in a modern economy. Major infrastructure failures during civil disturbances and natural disasters quickly and radically reduce communities' quality of life and productivity. Conversely, improving infrastructure services enhances welfare and fosters economic growth. Therefore, providing infrastructure services to meet the demands of businesses, households, and other users is one of the major challenges of economic development.

Developing countries invest $200 billion a year in new infrastructure—4 percent of their national output and a fifth of their total investment. This expenditure has resulted in a dramatic increase in infrastructure services: for transport, power, water, sanitation, telecommunications, and irrigation. During the past fifteen years, the share of households with access to clean water has increased by half, and power production and telephone lines per capita have doubled. These increases contributed a great deal toward increasing productivity and improving living standards[1].

In spite of these significant accomplishments, much more needs to be done. One billion people in the developing world still lack access to clean water, and nearly 2 billion lack adequate sanitation. Already-inadequate transport networks are deteriorating rapidly in many countries. Electric power has yet to reach 2 billion people, and in many countries unreliable power constrains economic output. The

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[1] World Bank, World Development Report 1994: Infrastructure for Development, (Washington D.C., USA: 1994), p. 1

demands for telecommunications, essential to modernize production and enhance international competitiveness far outstrip existing capacity. These existing deficiencies are further worsened by population growth and increased urbanization.

## 1.1 Infrastructure's Impact on Development

World Bank studies, and other similar works have illustrated infrastructure's links to three main components of development: economic growth, reduction of poverty, and the improvement of the environment[2].

### *1.1.1 Economic Growth*

Input-output tables for the economies of Japan and the United States show that telecommunications, electricity and water are used in the production process of nearly every sector, and that transport is an input for every commodity. Users demand infrastructure services not only for direct consumption but also for raising their productivity by, for example, reducing the time and effort needed to secure safe drinking water, to bring crops to market, or to commute to work.

Much research in recent years has been devoted to estimating the productivity of infrastructure investments. Studies attempting to link aggregate infrastructure spending to GDP show very high returns in a time-series analysis. Cross-national studies of economic growth and infrastructure also show that infrastructure variables are positively and significantly correlated with growth in developing countries. In both types of studies, however, whether infrastructure investment causes growth or growth causes infrastructure investment is not fully established. Moreover, there may be other factors driving the growth of both GDP and infrastructure that are not fully accounted for. Furthermore, neither the time-series nor the cross-sectional studies satisfactorily explain the mechanisms through which infrastructure may affect growth.

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[2] World Development Report 1994, p.14

It is evident, however, that a strong association exists between the availability of certain key infrastructure services (telecommunications, power, paved roads, and access to safe water) and per capita GDP. An analysis of the value of infrastructure stocks indicates that their composition changes significantly as incomes rise. For low-income countries, more basic infrastructure such as water, irrigation, and (to a lesser extent) transport are important. As economies mature into the middle-income stage, most of the basic consumption demands for water are met, the share of agriculture in the economy shrinks, and more transport infrastructure is provided. The share of power and telecommunications in investment and infrastructure stocks becomes more significant as these in turn move to the high-income category. Data for 1990 indicate that, while total infrastructure stocks increase by 1 percent with each 1 percent increment in per capita GDP, household access to safe water increases by 0.3 percent, paved roads increase by 0.8 percent, power by 1.5 percent, and telecommunications by 1.7 percent.

Although the above relationships suggest that infrastructure (especially those which are energy-related), has a high potential payoff in terms of economic growth, they do not provide a basis for prescribing appropriate levels, or sectoral allocations, for infrastructure investment. They also do not give a mechanism for predicting returns for a particular nation. Other evidence confirms that investment in infrastructure alone does not guarantee economic development and that actual returns for infrastructure are small, close to the return on private investments. This phenomenon may be due to the differences in the efficiency of investment across countries and over time. For example, a study of the economic returns to individual World Bank projects shows that, when overall economic policy conditions are poor, the returns to infrastructure investments decline. Some of the results of this study are presented in Table 1.1.

Table 1.1

Average economic rates of return on World Bank supported projects, 1974-92[3]

| Sector | 1974-82 | 1983-92 |
|---|---|---|
| Irrigation and drainage | 17 | 13 |
| Telecommunications | 20 | 19 |
| Transport | 18 | 21 |
| Airports | 17 | 13 |
| Highways | 20 | 29 |
| Ports | 19 | 20 |
| Railways | 16 | 12 |
| Power | 12 | 11 |
| Urban development | - | 23 |
| Water and sanitation | 7 | 9 |
| Water supply | 8 | 6 |
| Sewerage | 12 | 8 |
| Infrastructure projects | 18 | 16 |
| All Bank operations | 17 | 15 |

The average economic return on infrastructure projects, reestimated after loan disbursement (completion of project construction), has been 16 percent over the past decade—just above the World Bank average of 15 percent. Returns have been lowest (and declining) for irrigation and drainage, airports (for a very small sample), railways, power, water supply, and sewerage. Possible reasons for this phenomenon will be discussed later in the chapter.

### *1.1.2 Reducing Poverty*

Infrastructure is important for ensuring that growth is consistent with poverty reduction, and access to at least minimal infrastructure services is one of the essential criteria for defining welfare. To a great extent, the poor can be identified as those who are unable to consume a basic quantity of clean water, are subject to

[3] World Development Report 1994, p.17

unsanitary surroundings, have limited mobility beyond their immediate settlement and have extremely limited access to modern communications systems. Therefore, they have more health problems and fewer employment opportunities[4].

The construction and maintenance of some infrastructure—especially roads and waterworks—can contribute to poverty reduction by providing direct employment. Civil works programs (as carried out in Botswana, Cape Verde, and India), which often involve the provision of infrastructure, have also been important in strengthening famine prevention and providing income.

### 1.1.3 *Improving the Environment*

Infrastructure provision results from the efforts of individuals and communities to modify their surroundings or habitat in order to improve their comfort, productivity, and protection from the elements. Each sector—water, power, transport, sanitation, irrigation—raises issues concerning the interaction between artificial structures (and the activities they generate) and the natural environment. Environment-friendly infrastructure services are essential for improving living standards and offering public health protection. With sufficient care, providing the infrastructure necessary for growth and poverty reduction can be consistent with concern for natural resources and the global environment. At the same time, well-designed and -managed infrastructure can promote the environmental sustainability of human settlements.

The relationship between each infrastructure sector and the environment is complex. Power plant emissions are important contributors to air pollution, so their air quality impacts deserve careful analysis when facilities are expanded. In developing countries almost one-third of commercial energy is devoted to electricity generation—the fastest-growing component of the energy sector. By the year 2000 Asia may surpass all of Europe in sulfur dioxide emissions, and by 2005 it may surpass Europe and the United States combined in power plant emissions.

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[4] World Development Report 1994, p.20

Reservoirs associated with hydroelectric projects, flood control, or irrigation can give rise to environmental problems, both upstream (inundation of land) and downstream (sedimentation).

## 1.2 The Traditional Role of the Government in Infrastructure Provision

Many of the newly independent developing countries at the end of the Second World War displayed a fierce desire for economic independence[5]. They believed that rapid industrialization of the domestic economy was the key to development, and viewed planning and public ownership in key sectors as more effective ways to achieve this political and economic independence. Both macroeconomic and microeconomic justifications were given for this perspective:

### *1.2.1 Macroeconomic arguments for Government Provision*

- Government planning was essential to ensure that capital formation proceeded at the desired rate and that such capital was allocated in a manner commensurate with the development objectives of the country. Government planning, control, and direction came to mean centralized, physical planning of the economy in which the concept of market-determined prices was accorded secondary importance.
- Domestic resources had to be mobilized to overcome the saving constraint. Two methods of mobilizing domestic saving—taxation and financial intermediation—were widely exercised. Weak financial markets necessitated government intervention.
- Industrialization was seen to be the key to development because of empirical evidence on the historical economic development of the now-industrial countries. Developing countries felt that they had to nurture their infant

[5] Naya, Seiji, Private Sector Development and Enterprise Reforms in Growing Asian Economies, Institute for Contemporary Studies Press (San Francisco, USA: 1990). p.7

industries against competition at the early stages of development to support long-term development goals.

- In conjunction with the infant industry argument, "import substitution" was seen as a means for accelerating industrialization. This inward-looking strategy called for strong government intervention in erecting and maintaining projectionist barriers.

### *1.2.2 Microeconomic Arguments for Government Provision*

The micro foundations for government involvement are generally characterized as "market failures". Externalities, increasing returns to scale, and public goods are examples of these.

Externalities

An externality is said to exist when a third party not directly involved in the production or consumption of the output is either positively or negatively affected by the exchange. In developing countries, congestion in cities can be seen as an example of a negative externality. Such situations give rise to a divergence between private and social costs and benefits. Price theory predicts that, in the absence of government intervention, goods and services with negative external effects would be overproduced, and those with positive external effects will be underproduced.

Increasing returns to scale

A "natural" monopoly may arise because of the existence of increasing returns to scale, in which a given increase in all inputs produces a more than equi-proportional increase in output. This situation can lead to a firm's undercutting smaller firms, becoming a monopoly, and then setting its price above marginal cost. Water, electricity, telephone services and transportation are a few examples in which increasing returns to scale provide a strong case for public regulation or ownership.

Public Goods

Public goods are those goods that, once produced, are available for consumption by all; consumption of a public good by one individual does not reduce the availability of the good to others. Because of these characteristics, the producer of a public good cannot exclude nonpaying users and thus cannot fully collect fees for the sale or use of the good. As a result, private producers may not find it profitable to produce the public good, and the government becomes responsible for the provision of these goods.

Other considerations

In addition to the macroeconomic and microeconomic concerns, other objectives were also considered to be important to the country's long-run development. Many policy-makers in the developing world argued that the attainment of these goals required specific government action. Some of these include:

- Many governments viewed the fair distribution of income and the elimination of poverty and unemployment as critical goals of development. Governments responded in a variety of ways to reduce poverty, stimulate employment, and achieve a fairer distribution of income, each of which implied an increased role of the government in the economy.
- The private sector cannot be relied on to ensure balanced regional development because private capital generally seeks out investment in areas and markets nearer to ports and big cities. Therefore, government action is essential to invest in areas ignored by the private sector.
- National security considerations also provide a rationale for governments to intervene in the control over and production of "strategic" goods and services such as heavy and chemical industries, transportation, and communications. State-owned enterprises are the principal means through which governments gain and exercise control over these areas of their economies.

### 1.2.3 *The Government Record of Performance*

Achievements[6]

There has been impressive expansion within infrastructure in recent decades, as measured by stocks and production of services. In low-income economies, telecommunications, sanitation, and water supply registered the highest rates of increase in availability between 1975 and 1990, starting from a very low base in each sector. In middle-income economies, growth in this period was concentrated mainly in the power and telecommunications sectors, where capacity more than doubled between 1975 and 1990. The above trends are illustrated in the table below:

[6] World Development Report 1994, p.25

Table 1.2
Expansion of infrastructure coverage in low-, middle-, and high-income countries in recent decades[7]

| Sector | Low-income economies | | | Middle-income economies | | | High income economies, 1990 |
|---|---|---|---|---|---|---|---|
| | *1975* | *1990* | *Annual % increase* | *1975* | *1990* | *Annual % increase* | |
| Power-generating capacity (1000 kW per million persons) | 41 | 53 | 1.6 | 175 | 373 | 4.7 | 2,100 |
| Telecommunications (main lines per thousand persons) | 3 | 6 | 3.2 | 33 | 81 | 5.6 | 442 |
| Sanitation (% of population with access) | 23 | 42 | 3.8 | 44 | 68 | 2.7 | 95+ |
| Paved roads (km per million persons) | 308 | 396 | 1.6 | 1,150 | 1,335 | 0.9 | 10,106 |
| Water (% of population with access) | 40 | 62 | 2.7 | 54 | 74 | 2.0 | 95+ |

7 World Development Report 1994, p.26

Table 1.3

Common management problems in public sector infrastructure entities, 1980-92: percentage of World bank loans in which conditions were imposed to address the problem area[8]

| Sector (number of loans) | Unclear Goals | Lack of management autonomy and accountability | Financial problems | Wages and labor problems |
|---|---|---|---|---|
| Electricity (48) | 27.1 | 33.3 | 72.9 | 31.3 |
| Water (40) | 25.0 | 40.0 | 70.0 | 35.0 |
| Telecom (34) | 14.7 | 35.5 | 52.9 | 32.4 |
| Rail (39) | 15.4 | 20.5 | 53.8 | 33.3 |
| Road (35) | 8.6 | 22.9 | 40.0 | 40.0 |
| Ports (28) | 21.4 | 35.7 | 32.1 | 42.9 |

[8] World Development Report 1994, p.39

### 1.2.4 *Problems*

A survey of forty-four countries with World Bank-financed projects designed to improve infrastructure performance revealed some of the most common problems in six infrastructure sectors. The results are presented in Table 1.3.

Although each sector has special problems, there are common patterns-- operational inefficiencies, inadequate maintenance, excessive dependence on fiscal resources, lack of responsiveness to users' needs, limited benefits to the poor, and insufficient environmental responsibility[9].

Operational Inefficiencies

The broadest indicator of inefficient performance by an infrastructure system is the extent of output lost in delivery. In 1987 25 percent of the power utilities in developing countries had losses of electricity in transmission and distribution that were twice those in efficiently operated systems. The World Bank estimated that in some African countries, spending $1 million to reduce losses could save $12 million in generating capacity.

Inefficient use of labor is especially common and costly in infrastructure. At various periods, two thirds of the labor in railways in Tanzania and Zaire, 80% of port staff in Argentina (before recent privatizations), and one-quarter of highway department staff in Brazil have been redundant, according to World Bank estimates. Overstaffing is also common in water, power and telecommunications.

Inadequate maintenance

Closely related to operating inefficiencies is lack of maintenance, which causes loss of capacity and subsequent decline of output. Therefore, substantial additional investment is needed simply to sustain existing levels of service.

Poor maintenance practices account for some of the low availability of power generating capacity, which averages less than 60% for thermal plants in many

[9] World Development Report 1994, p.27

developing countries, compared with more than 80% in systems operated at best-practice standards.

## Fiscal Inefficiency and Fiscal Drain

Poor infrastructure policies and inefficient provision absorb scarce fiscal resources and damage macroeconomic stability. Because prices are often held well below costs, the subsidies flowing into public infrastructure enterprises and agencies have been enormous in many countries. During the 1980s, power tariffs in developing countries were well below the costs of operation and maintenance.

## Unresponsiveness to User Demand

The result of inefficiency and poor maintenance is low-quality, unreliable service, which alienates users. Reliability is a critical aspect of user satisfaction that is often ignored by many state-owned enterprises. In Indonesia and Nigeria, private businesses incur heavy costs in order to guarantee power supply: 92 percent of firms sampled in Nigeria and 64 percent in Indonesia have installed private generating capacity, in contrast to Thailand, where only 6 percent of companies needed generators. These large differences in self-provision reflect the performance of the formal suppliers. In Nigeria, only 43 percent of installed capacity was in service by 1990 (despite massive over-investment in public power-generating capacity throughout the 1980s); in Thailand, the power utility is efficiently run.

## Neglect of the Poor

The poor typically use fewer infrastructure services than the non-poor, not only because of low income, but also because they have very low access. Many countries have introduced subsidies through low tariffs with the aim of improving the poor's access to infrastructure services, yet most of these hand-outs have been captured by the middle- and high-income households. For example, flat-rate electricity charges in rural India have benefited mainly rich households, because the poor lack the income to purchase the pumps and consumer appliances that account for most electricity use.

Neglect of the Environment

The process of extracting energy resources and converting them into electricity has often led to environmental degradation. One of the first motivations for an energy conservation movement in the US was a concern that energy production was leading to environmental problems: air pollution from coal-fired power plants, water pollution from mine drainage, oil spills, threats to scenic landscapes and endangered species, and similar consequences[10].

USAID projections of power supply capacity in developing nations by the year 2008 show large increases in hydropower and steam thermal (mainly coal) facilities, when these particular options are likely to have serious environmental consequences[11]. Hydropower developments on a relatively large scale often require the relocation of sizable populations and change river basin ecologies dramatically: careful studies of environmental impacts and risks in the more affluent countries have sharply reduced the use of this alternative. Coal-fired power generation has historically been associated with emissions of particulate materials, sulfur dioxide, oxides and nitrogen, and other substances that eventually cause undesirable environmental and health impacts-- not only air emissions from the power plants themselves but water emissions from mining, cleaning, and storage facilities. The problem of global climactic change is serious: a rise in temperature, shifts in climatic zones, a rise in the sea level, and other disruptive impacts that may result from growing concentrations in the earth's atmosphere of carbon dioxide and other by-products of fossil fuel use.

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[10] US Agency for International Development, Power Shortages in Developing Countries: Magnitudes, Impacts, Solutions, and the Role of the Private Sector, (Washington D.C., USA: March 1988), p.15
[11] USAID, Power Shortages......, p.15

If developing nations do not use extensive use of state-of-the-art technologies to control sulfur dioxide emissions, their total emissions are expected to at triple over the next 20 years (according to USAID figures). This figure could be even higher because some of the larger developing countries, such as India and China, are planning a major commitment to coal.

However, it must be kept in mind that, at present, developing countries enjoy extremely limited access to electric power, and their contributions to wide-scale environmental problems is small relative to those of more developed nations. The US alone has over 650 GW of installed capacity compared with 450 GW in the entire developing world, and industrialized countries produce 70 percent of the world's energy-related carbon dioxide. Yet, since the *projected* increases in emissions from the poorer countries are high, addressing the problem of global environmental pollution requires a concerted effort by all nations.

## 1.3 The Power Crisis in the Developing World

The problems with state sponsored infrastructure provision outlined above are especially acute in the power sector of developing nations. In this section I will describe the current situation in these nations, and the possible costs of the severe electricity shortage they are currently facing.

### *1.3.1 Electric Power and Economic Development*

As a country develops economically, it consumes increasing amounts of energy per capita. Furthermore, diverse activities such as agricultural development, improvements in health services, and industrial expansion are closely tied to changes in the quality and form of energy consumed. Therefore, prospects for a country's growth are closely linked to its ability to provide an adequate and reliable supply of energy to its population[12].

[12] USAID, Power Shortages......, p.2

Electricity, as a especially high grade of energy, plays an important role in the development process. World Bank studies of which review the previous patterns of electricity consumption in developed and developing countries indicate that electricity use and GDP have been, and probably will be, strongly correlated. The fact that, between 1970 and 1980, annual GDP growth rates of developing countries were accompanied by an electricity consumption growth of 7 percent an year, illustrates the strong link between increased power consumption and economic growth.

In spite of the high annual growth rate of electricity demand in developing countries, these nations, which over 75 percent of the world population, consume only 18 percent of all the electricity used in the world. On average, they use only 500 kWh of electricity per capita per year, compared with over 10,500 kWh per capita in the US and over 5,000 kWh per capita in Europe and Japan. The lowest income countries, use on average only 250 kWh per capita per year.

### 1.3.2 *The Impact of Power Shortages in Developing Nations*

A sizable imbalance between the supply and demand of electric power in developing countries is constraining their efforts to achieve sustainable social and economic growth. Faced with high demand growth rates, many countries now experience power shortages of over 10 percent of their generation capability. In Pakistan, for example, during the past five years, power shortages have been over 25 percent of demand. The corresponding figures for India and the Dominican Republic are 10 and 15 percent respectively. The impact of these shortages on the growing economies of developing countries has been tremendous. In Pakistan, for example, load shedding has resulted in an estimated 1.8 percent decrease in GDP and a 4.2 percent decrease in the country's foreign exchange earnings (according to USAID estimates. The poor quality and reliability of existing electricity services in the country has significantly impaired industrial, agricultural, and commercial productivity, and diverted much needed investment capital for redundant, standby electrical generating capacity.

The following table gives USAID estimates[13] of the costs of power shortages in some developing countries:

[13] USAID, Power Shortages......, p.21

Table 1.4

Costs of Power Shortages in Selected Developing Countries (1988 US$)[14]

| Country | Sector | Type of Shortfall | Cost of Shortage |
|---|---|---|---|
| Bangladesh | All | Unplanned Outages | 1.00 $/kWh |
| Brazil | Households | Unplanned outages | 1.95-3.00 $/kWh |
| Chile | Households<br><br>Industry | Unplanned outages<br><br>Unplanned outages | 0.53 $/kWh<br><br>Range: 0.25-12.00 $/kWh<br>Central Tendency: 1.50-6.00 $/kWh |
| Costa Rica | Households | Unplanned outages | --- |
| Egypt | Industry | Unplanned outages | 0.40 $/kWh |
| India | Industry | Controlled load shedding | Annual cost ranges from 1 to 3% of GDP (1.5 to 3 billion dollars annually) |
| Jamaica | Industry | Unplanned outages | 1.25 $/kWh |
| Pakistan | Industry | Controlled load shedding<br><br>Unplanned outages<br><br>Controlled and uncontrolled load Shedding | Range: 0.26-1.77 $/kWh<br>Average: 0.46 $/kWh<br><br>Range: 0.36-2.54 $/kWh<br>Average: 0.46 $/kWh<br><br>$350 million in 1984-85 |
| Paraguay | Residential | Unplanned outages | --- |
| Taiwan | Industry | Unplanned outages | 0.06-2.16 $/kWh |
| Tanzania | Households<br>Industry<br>Commercial<br>All Sectors | Unplanned outages<br>Unplanned outages<br>Unplanned outages<br>Unplanned outages | 0.50 $/kWh<br>0.07-1.40 $/kWh<br>1.00 $/kWh<br>0.07-1.10 $/kWh |

Many governments in developing nations have found it increasingly difficult to allocate sufficient resources to the power sector. In many countries this sector accounts for more than 20 percent of the government's total development budget,

[14] USAID, Power Shortages......, p.21

and foreign borrowing for the power sector is greater than 40 percent of their total foreign debt. Low development growth rates, very low per capita incomes, substantial debt servicing problems, and political instability in these nations restrict their ability to procure investment capital from domestic and foreign sources.

## 1.4 The changing role of the government

The traditional role of the government in infrastructure provision, which was outlined above, began to change gradually. Since the 1980s, this process has speeded up due to changes both in the external global economy, as well as internal changes.

### External Changes

The 1980s were generally difficult years for most developing countries, as they had to contend with a rapidly changing world economy. Exports of developing countries as a whole fluctuated widely, declining in the first half of the 1980s but recovering in 1987. Two oil shocks and prolonged recessions led to balance-of-payments problems for oil-importing countries, and the softening of the oil market in the 1980s even created difficulties for the oil-rich countries. For commodity-exporting countries, the prolonged period of low commodity prices resulted in low or drastically reduced export earnings[15].

At the same time, flows of external capital into developing countries have slowed. The high interest rates in the early 1980s increased the debt-servicing burden and caused repayment difficulties for many developing countries. Concurrently, problems in industrialized countries led to a stagnation in aid and other official bilateral flows. Thus, despite falling interest rates in the mid-1980s, external sources of funds were not readily available to most developing countries.

[15] Naya, p. 15

As a result of the above external factors, many governments have begun to look more to the private sector to share the responsibility of the provision of infrastructure in many sectors.

Internal Factors

Uncertain external conditions have also contributed to a more circumspect view of public finances. Rising debt and growing budget deficits of many countries have caused them to look more carefully into their expenditure patterns. Most developing countries suffered overall budget deficits for most of the 1980s.

Because of these budgetary problems, several governments have become more cost-conscious. They are reassessing government's traditional role in the economy and are preparing to withdraw from activities deemed more suited for private initiative.

### 1.5 Worldwide Privatization

During the 1970s, 1980s and 1990s governments worldwide have been selling off state-owned assets, primarily as an additional source of revenue. In 1988-92 the UK government led the privatization league accruing some US$ 44 billion. But, if assets sales were expressed relative to GDP, the governments of New Zealand, Mexico, Argentina, Malaysia and Portugal sold larger proportions of their economy, as shown in Table 1.4[16]:

[16] Smith, A.J. and C. Walker, Privatized Infrastructure: the Build Operate and Transfer approach, Thomas Telford Publications Ltd (London, United Kingdom: 1995), p.12

Table 1.4: Privatization Proceeds relative to GDP 1988-92 Average[17]

| Country | Value ( US$ billions) | Approximate % of GDP |
|---|---|---|
| New Zealand | 7.6 | 3.60 |
| Mexico | 20.2 | 1.70 |
| Argentina | 9.3 | 1.40 |
| Malaysia | 2.7 | 1.25 |
| Portugal | 3.3 | 1.10 |
| Britain | 44.4 | 0.95 |
| Germany | 27.3 | 0.50 |
| Sweden | 4.1 | 0.45 |
| Australia | 4.5 | 0.40 |
| South Africa | 1.4 | 0.40 |
| Ireland | 0.5 | 0.30 |
| Brazil | 4.6 | 0.25 |
| Canada | 5.7 | 0.25 |
| Holland | 2.4 | 0.20 |
| Austria | 1.1 | 0.20 |
| Japan | 22.8 | 0.20 |
| Spain | 2.7 | 0.15 |
| Denmark | 0.7 | 0.15 |
| Italy | 3.4 | 0.10 |
| France | 2.1 | 0.10 |

In New Zealand, sales of state assets were equivalent to an average of 3.6% of GDP in the five-year period, compared with just under 1% in the UK. Another country which is preparing for large scale privatization is India, which plans to sell US$ 1.3 billion worth of public assets between 1994 and 1996. The assets targeted for sale include over 200 state-sector companies in mining, oil, telecommunications, steel, aviation, ports, shipbuilding, railways, bus transport, and hotels. The demise of communism in the East European countries triggered off a tidal wave of mass privatization. The European Bank for Reconstruction and Development (EBRD), with Germany's 'Trenchant' privatization agency in partnership with the World Bank led the financing of this thrust.

All countries have their own public/private mix, which allied to their political ethos, determines the extent and nature of privatization. Therefore, governments have to address their own unique political climate. Privatization might

[17] Smith and Walker, p.13

reverse previous nationalizations which could upset those who advocated that policy in the first place. In non-democratic regimes, where the military is often close to nationalist activists and supposed defenders of the poor and under-privileged, as in some Central African states, private sector involvement is generally resisted.

In democratic countries opposition can be expressed by casting votes in favor of the opposing political party, and state officials therefore can regularly gauge satisfaction with the process by following periodic election results. Political opposition to the private sector is often based on ideological grounds or driven by self-interest considerations, but also arises from government departments fearing that privatization will lessen their power.

Reservations that privatization is not a panacea are also voiced by agencies such as the United Nations Development Project (UNDP) which has monitored its overall consequences in 80 countries[18]. Its 1993 report states that "markets are, after all, not an end in themselves, they are a means to human development". To keep human development and the market in balance it warns of the "seven deadly sins of privatization":

a) The wrong reason, such as the short-term revenue for the national treasury
b) The wrong environment; for instance, the government either continues to interfere with efficiency or provides inadequate anti-trust regulation.
c) Cronyism and corruption by disposing of assets in secrecy or without competitive bidding.
d) Financing budget deficits by selling public enterprises. Instead, a government must retire its national debt and face up to the painful choice of raising taxes or cutting public spending to balance its budget.
e) A poor financial strategy. Government should take care to achieve widespread distribution of shares to nationals and foreigners alike in a way that maximizes revenue and protects the national interest.

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[18] Smith and Walker, p.14

f) Poor labor strategies, such as buying labor cooperation with unrealistic hiring promises. Instead, governments should invite pre-sale labor dialogue and participation in management, in retraining, and in lay-off policies and action.
g) No political consensus. Privatization is a political as well as an economic act and should not be forced through by edict.

"The enumeration of these sins," say the report's authors, "is a caution not against privatization, but against privatizing within the wrong framework and without a human development purpose in mind"[19].

## 1.6 *The Power Shortage in Sri Lanka*

Sri Lanka, a developing nation in Asia, faces many of the infrastructural problems outlined above, especially those related to electricity generation. In the next few chapters I will provide a general background on the country and its power sector, and indicate some of the specific problems faced by its power planners. I will then provide some possible measures (including the privatization options outlined above), that the government can undertake to meet the country's rapidly growing demand for electricity.

[19] Smith and Walker, p.14

# CHAPTER 2

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# Sri Lanka: Background, Economy, Government Policy, Energy Sector

## 2.1 Country Overview

Sri Lanka is an island to the south of the Indian subcontinent which is separated from the mainland by a narrow strip of ocean—the Palk Strait—which, at its narrowest point is only 22 miles wide. The island is located between 6 and 10 degrees North latitude and 79 and 82 degrees East longitudes. Sri Lanka is a pear shaped island, 270 miles (430 km) long at its longest point and 140 miles (220 km) wide at the widest point. It covers an area of 25,332 square miles (65,610 square kilometers), is comparable in size to Ireland or the state of West Virginia, and carries the population of Australia[1].

Sri Lanka received independence in 1948, after three centuries of Western rule by the Portuguese, Dutch, and the British. The nation's capital, Colombo, is situated on the West coast, and has a population of 615,000.

### *2.1.1 Basic Facts*

Population

Sri Lanka's population, which was 14,988,000 at the 1981 census (the decennial census was not carried out in 1991), was officially estimated at 17.9 million in mid-1994. The annual growth rate over the period 1981-91 was 1.4% and was estimated at 1.4% in 1994[2].

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[1] Central Bank of Sri Lanka, Sri Lanka: An Economic, Financial and Investment Guide (Colombo, Sri Lanka: June 1992), p. 3

[2] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, Electronic Publishing Services (London, United Kingdom: 1995), p.11

About 70% of the population live in the island's south-western area (the so-called wet zone), which accounts for about three-quarters of the cultivated land and most of the country's industry. In 1991 only 21% of the population was urban, a proportion little changed from 15 years earlier.

The fertility rate (average number of children born per woman) is estimated at 2.4. Contraceptive use is relatively high (practiced by around 62% of married women of childbearing age) and the fertility rate is expected to fall to the population replacement level before the end of the century. About 30% of the population are under 15 and 6% over 65.

Ethnic Makeup

Ethnicity has played a major role in Sri Lankan politics since independence. The majority Sinhalese account for nearly three-quarters of the population; they speak Sinhala (an Indo-Aryan language), and are mainly Buddhist[3].

The Sri Lankan Tamils account for 13% of the population. By majority Hindu, with a substantial Christian minority, they speak Tamil, a Dravidian language, which is based on a different rootstock from Sinhala. Upcountry, or "Indian" Tamils form 5-6% of the population. They are descendants of laborers brought over by the British to work the tea plantations at the beginning of the century, and many were denied voting rights or citizenship after independence. Although a 1964 Treaty with India sought to regularize their status, all those remaining in Sri Lanka (some returned to India) were finally granted citizenship only in 1988.

The Muslims, or Moors, constitute around 7% of the population and are concentrated in the Eastern Province and in Colombo. Descendants of Arab traders who settled in the island, they are Tamil-speaking, but remain apart from the Tamil community and are not involved in Tamil causes.

[3] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.4

Finally, there are small groups of "Burghers" (Eurasians of mixed descent), Malays, and a tiny handful of Veddahs (descendants of the original inhabitants of the island before Sinhalese settlement).

Table 2.1

Percentage Distribution of Population by Religion and Ethnicity[4]

| Percentage by Ethnicity | | Percentage by Religion | |
|---|---|---|---|
| Sinhalese | 74.0 | Buddhists | 69.3 |
| Sri Lankan Tamils | 12.7 | Hindus | 15.5 |
| Indian Tamils | 5.5 | Muslims | 7.6 |
| Moors | 7.0 | Christians | 7.5 |
| Burghers | 0.3 | Others | 0.1 |
| Malays | 0.3 | | |
| Others | 0.2 | | |

(1981 Census; Total Population: 14,850,000)

Tensions between the majority Sinhalese, and minority Tamils escalated into a bloody ethnic conflict in 1983. Fighting between government forces and a group of militants known as the LTTE (Liberation Tigers of Tamil Eelam), who are seeking a separate state in the North and East of the island, has claimed over 50,000 lives and caused immense damage to public and private property.

## Government

Despite its problems, Sri Lanka has managed to maintain an unbroken record of democracy since independence. Elections have been held regularly and they have been in general freely and fairly contested, (in spite of some abuses). The country passes the critical test of any democracy in that elections have on several occasions resulted in a peaceful change of government.

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[4] Central Bank of Sri Lanka: Statistics Department, Economic and Social Statistics of Sri Lanka (Colombo, Sri Lanka: December 1994), p.9

Initially, as Ceylon, the country had a Westminister-style constitution with the British monarch as head of state, executive power in the hands of a prime minister, and a bicameral legislature. In 1972 the country became a republic, although remaining within the Commonwealth. Its name was changed from Ceylon to Sri Lanka and the bicameral legislature became unicameral. Although it had a president as head of state, executive power remained vested in the prime minister and cabinet.

Sweeping changes were instituted in 1978 after J.R. Jayawardene became prime minister in 1977. The new constitution introduced a presidential system of government with the president becoming head of state, head of government, and head of the armed forces. The powers of the prime minister and the cabinet were drastically reduced. The previous first-past-the-post system of voting in elections was replaced by a system of modified proportional representation (modeled after portions of the French and German political systems). Both presidential and parliamentary elections are held every six years. Mr. Jayawardene became the first president under the 1978 constitution and held this position for two six-year terms until the end of 1988.

A two-thirds parliamentary majority is required for the removal of the president or for an amendment to the constitution. The judiciary is independent and the Supreme Court has sole jurisdiction over interpretation of the constitution.

Freedom of thought, conscience, and worship, as well as equal access before the law, are guaranteed by the constitution. Sinhala and Tamil are official languages, and English, widely used and understood in business circles, has a high status as a link language.

Social Indicators

The education system, which was targeted as a high priority by the government after independence, is highly advanced by developing country standards. The government spent 11% of its total expenditure on education in 1994, an increase of 26% from the 1993 level. The pupil to teacher ratio was 22:1 in 1994, down from 24:1 in 1991. Primary schooling is universal. Secondary school enrollment was 74% in 1991 and 5% of the eligible population was receiving higher education. In 1990, 88% of the population was literate, the highest rate in South Asia.

The health service is also impressive for a country of Sri Lanka's per capita GDP. Medical treatment is free. Life expectancy, which was 72 years at birth in 1992, is higher than in any other country in the subcontinent. Infant mortality, at 18 per 1,000 live births in 1992, is comparable to that of a West European country in the 1960s.

For a relatively poor country Sri Lanka's record on both education and health is exceptional. The UN's human development index, which combines real GDP increase with indicators such as life expectancy, literacy, and schooling data, puts Sri Lanka at 0.704. This ranks five places above the country's ranking in terms of GDP per capita.

Table 2.2: Vital Statistics: Sri Lanka Compared with Selected Countries[5]

| Item | Ref. Year | Sri Lanka | Bangla-desh | India | Indo-nesia | Rep. of Korea | Malay-sia | Pakis-tan | Philip-pines | Singa-pore | Thai-land |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Mid-year Population, Million. | 1992<br>1993 | 17.4<br>17.6 | 111.4<br>113.2 | 867.8<br>-- | 186.0<br>189.3 | 43.7<br>44.1 | 18.6<br>19.1 | 119.1<br>122.8 | 63.4<br>65.0 | 2.8<br>2.9 | 57.8<br>58.6 |
| Population Growth Rate % | 1992<br>1993 | 1.0<br>1.2 | 1.6<br>1.6 | 1.9<br>-- | 1.6<br>1.7 | 0.9<br>0.9 | 2.2<br>2.7 | 3.1<br>3.1 | 2.1<br>2.5 | 0<br>3.6 | 1.6<br>1.4 |
| Population Growth %<br>Annual Average Growth % | 1980-93<br>1980-93 | 18.9<br>1.4 | 29.1<br>2.2 | 28.9<br>2.4 | 27.8<br>2.1 | 15.7<br>1.2 | 38.4<br>2.9 | 48.7<br>3.7 | 35.1<br>2.7 | 26.0<br>2.0 | 25.5<br>1.9 |
| Pop. Density per sq. km | 1992 | 279 | 774 | 264 | 98 | 441 | 56 | 150 | 211 | 4,666 | 113 |
| Urban Population (As a % of Total Pop.) | 1993 | 22 | 20 | 26 | 31 | 74 | 43 | 32 | 43 | 100 | 34 |
| Crude Birth Rate per '000 | 1991 | 21 | 34 | 30 | 25 | 16 | 28 | 41 | 28 | 18 | 21 |
| Crude Death Rate per '000 | 1991 | 6 | 13 | 10 | 9 | 6 | 5 | 11 | 7 | 5 | 6 |
| Natural Increase of Population per '000 | 1991 | 14 | 21 | 20 | 16 | 10 | 23 | 30 | 21 | 13 | 15 |
| Fertility Rate (Births per Woman) | 1991 | 2.5 | 4.5 | 3.9 | 3.0 | 1.8 | 3.7 | 5.7 | 3.6 | 1.8 | 2.3 |
| Infant Mortality Rate (per '000 live births) | 1992 | 18 | 109 | 89 | 66 | 21 | 14 | 99 | 40 | 8 | 26 |
| Life Expectancy at Birth | 1992 | 71 | 52 | 60 | 62 | 70 | 70 | 58 | 65 | 74 | 69 |

[5] Central Bank of Sri Lanka: Statistics Department, Economic and Social Statistics of Sri Lanka, p.5

### 2.1.2 *The Economy*

Sri Lanka's economy is still largely agricultural. A quarter of GDP is generated by this sector, and about 44% of its labor force employed by it[6]. In recent years, in response to government efforts to diversify the economic base and generate new sources of foreign exchange, industry (manufacturing in particular), and services (tourism and banking) have grown in importance. In 1986 the textiles and clothing sector became the leading foreign exchange earner, while the three main traditional exports—tea, rubber, and coconut—now accounted for less than one-fifth of earnings.

Real GDP growth has averaged 4.8% in the last five years. A growth rate of 4.3% was achieved in 1992 despite a severe drought which caused a drop in agricultural output. The beneficial impact of economic reforms, along with growing foreign investment, enabled the rest of the economy, notably manufacturing, to offset poor agricultural performance. In 1993 agricultural recovery helped push economic growth to 6.9%. Agricultural growth slowed to 3.3% in 1994, but overall economic growth to a still respectable 5.6%[7]. These impressive rates were achieved in spite of the ongoing civil war which has had an extremely adverse impact on the economy.

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[6] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.13

[7] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.13

Table 2.3: Composition of GDP in real terms[8]

| | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|
| Agriculture, forestry and fishing | 22.7 | 23.2 | 22.6 | 21.3 | 20.9 | 20.5 |
| Mining and quarrying | 2.9 | 3.0 | 2.6 | 2.3 | 2.4 | 2.5 |
| Manufacturing | 16.8 | 17.4 | 17.7 | 18.5 | 19.1 | 19.7 |
| Construction | 7.0 | 6.8 | 6.7 | 6.9 | 6.9 | 6.9 |
| Utilities | 1.3 | 1.3 | 1.3 | 1.3 | 1.4 | 1.5 |
| Transport & communications | 11.4 | 11.1 | 11.5 | 11.8 | 11.5 | 11.2 |
| Internal Trade | 21.0 | 20.5 | 21.1 | 21.3 | 21.6 | 21.8 |
| Banking, insurance & real estate | 5.1 | 5.1 | 5.1 | 5.1 | 5.3 | 5.5 |
| Ownership of dwellings | 3.0 | 2.9 | 2.8 | 2.7 | 2.5 | 2.4 |
| Public administration & defense | 5.0 | 4.9 | 4.7 | 4.6 | 4.4 | 4.3 |
| Other services | 3.7 | 3.8 | 4.0 | 4.1 | 3.9 | 3.8 |
| **GDP at factor cost** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** | **100.0** |
| Net factor income from abroad | -2.3 | -2.2 | -2.2 | -2.1 | -1.5 | -1.6 |
| **GNP** | **97.7** | **97.8** | **97.8** | **97.9** | **98.5** | **98.4** |

Table 2.4

Growth in Output[9]

| | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|
| Agriculture, forestry, and fishing | -1.1 | 8.5 | 1.9 | -1.6 | 4.9 | 3.3 |
| Mining and quarrying | 5.4 | 9.1 | -10.0 | -6.0 | 11.9 | 6.0 |
| Manufacturing | 4.4 | 9.5 | 6.8 | 8.8 | 10.5 | 9.1 |
| Construction | 0.6 | 2.9 | 3.1 | 8.1 | 6.5 | 6.0 |
| Services | 3.2 | 4.3 | 6.2 | 5.3 | 6.3 | 5.2 |
| **GDP at factor cost** | **2.3** | **6.2** | **4.6** | **4.3** | **6.9** | **5.6** |
| **GNP** | **2.3** | **6.4** | **4.6** | **4.4** | **7.7** | **5.3** |

There has been a slow but steady decline in agriculture's importance in the composition of GDP. Manufacturing has performed exceptionally well in recent years, its growth becoming more impressive as the relative size of the sluggish public sector has declined, enabling private industry to predominate. Banking, insurance, and real estate have been the other buoyant sectors. The share of mining and quarrying has fluctuated.

[8] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.16

[9] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.16

## Employment

The total labor force, excluding the Northern and Eastern provinces, has risen from 5.8 million in 1992 to 6.17 million in 1994, of whom 5.4 million were employed. At the end of 1994 employment in the public sector was 1.32 million, of whom around 625,000 were in semi-government institutions (including state-owned plantations) [10].

A survey of the labor force carried out by the Department of Census and Statistics in 1994 (other than in the Northern and Eastern Provinces) suggested that the agricultural sector accounted for around 42% of total employment, manufacturing for about 14%, and the services sector (including hotels and distribution) for 40%. Over the past few years there has been a slow decline in the share of agriculture and an increase in the shares of manufacturing and services.

Unemployment, particularly among the educated young, has been a problem for many years in Sri Lanka, although the rapid economic growth of recent years has alleviated the problem to some extent. There is little reliable data on unemployment, but the Central Bank estimates that unemployment fell slightly from 13.5% of the workforce in 1993 to 13.1% in 1994.

## Currency

The unit of currency is the rupee, which is divided into 100 cents. The entire exchange system was fundamentally reorganized as part of the economic reforms introduced in November 1977. The currency was allowed to float against a basket of currencies, with the Central Bank daily announcing new exchange rates against major currencies. The value of the rupee has fluctuated since 1978 but its overall trend has been downwards, reflecting the country's persistent current account deficit and relatively high inflation rates. After a sharp fall against the dollar in 1989 the rupee remained around SLRs.40:$1 until early 1991, after which it steadily lost until mid-1993.

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[10] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.17

From mid-1993 to mid-1994 it fluctuated between SLRs.49.0:$1 and SLRs.49.7:$1, and dipped below the SLRs.50:$1 barrier in February 1995[11].

Table 2.5: Exchange Rates[12]

| | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|
| Dollar | 40.00 | 40.20 | 42.60 | 46.00 | 49.60 | 50.00 |
| Sterling | 65.00 | 75.60 | 79.60 | 69.40 | 73.50 | 78.10 |
| D-mark | 23.70 | 26.20 | 28.0 | 28.60 | 28.70 | 32.20 |
| French Franc | 6.94 | 7.71 | 8.19 | 8.39 | 8.47 | 9.32 |
| Yen (rupees per 100 yen) | 28.20 | 29.40 | 33.90 | 37.00 | 44.30 | 50.00 |
| Indian rupee | 2.36 | 2.23 | 1.64 | 1.75 | 1.58 | 1.59 |
| SDR | 52.6 | 57.20 | 60.80 | 63.30 | 68.10 | 73.00 |

Table 2.6: Average exchange rate (SLRs.:$)[13]

| 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| 36.05 | 40.06 | 41.37 | 43.83 | 48.32 | 49.42 |

11 Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.12

12 Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.12

13 Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.12

Interest Rates

Short term interest rates fluctuated widely during 1994. Continued high liquidity conditions in the economy within the context of a depleted stock of treasury bills in the Central Bank portfolio led to a sharp fall in short term interest rates during the first two months of 1994. With the tightening of liquidity conditions through the issues of treasury bills and Central Bank securities during the following months , short term interest rates moved in an upward direction until May 1994. This temporary upward trend was followed by another fall that continued until October due to increased liquidity following a rise in foreign inflows. A slowing down in foreign inflows and increased government borrowing caused short term interest rates to rise sharply in the last two months of the year. However, medium and long term rates remained at levels lower than the rates in 1993.

Table 2.7: Interest Rates[14]

| Item | 1986 | 1987 | 1988 | 1989 | 1990 | 1991 | 1992 | 1993 |
|---|---|---|---|---|---|---|---|---|
| **Central Bank Adv. Rate** | **11** | **10** | **10** | **14** | **15** | **17** | **17** | **17** |
| **Inter-Bank call Loans** | **12-12.75** | **11-14** | **16-21** | **13-25** | **14-19** | **13-27** | **10-32** | **16.5-28** |
| **Treasury Bill Yield Rates** | | | | | | | | |
| 3 Months | 11.31 | 11.31 | 19.32 | 18.10 | 17.41 | 16.33 | 17.67 | 18.09 |
| 6 Months | -- | -- | -- | 18.20 | 18.02 | 16.38 | 18.05 | 19.47 |
| 9 Months | -- | -- | -- | 19.10 | 19.10 | 17.43 | 18.99 | 19.38 |
| **Commercial Bank Deposit Rates** | **6-12** | **6-11** | **5-11** | **5-14** | **5-14** | **6.5-14** | **6.5-14** | **6-15** |
| **NSB Deposits Rates** | **12** | **12** | **12** | **14** | **16.2** | **14** | **14** | **14** |
| **Commercial Bank Advance Rates** | | | | | | | | |
| Prime Lending Rate | 14.8 | 14.2 | 16.9 | 18 | 18.6 | 19.6 | 20.2 | 20.4 |
| Loans Secured by Government Securities | 12-26 | 9.8-26 | 9.8-26 | 9.8-25 | 9.8-25 | 11.8-28 | 11.8-26 | 16-26 |
| Unsecured Loans | 9.8-30 | 9.8-33 | 13-33 | 13-33 | 13-35 | 13-33 | 13-32 | 16.5-36 |
| Bills purchased and discounted | 11-22 | 11-22 | 10-25 | 7-25 | 10-25 | 10-30 | 14.5-30 | 14.5-30 |

[14] Central Bank of Sri Lanka: Statistics Department. Economic and Social Statistics of Sri Lanka, p.77

Table 2.8

Summary of Government Fiscal Operations[15]

| Item | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| **Total Revenue (Rs. million)** | **67,964** | **76,179** | **85,781** | **98,339** | **110,038** |
| Tax Revenue | 61,206 | 68,157 | 76,353 | 87,891 | 99,417 |
| Non Tax Revenue | 6,758 | 8,022 | 9,428 | 12,448 | 10,621 |
| **Total Expenditure & Net Lending** | **99,814** | **119,527** | **116,973** | **140,460** | **167,768** |
| Recurrent | 71,771 | 83,756 | 89,639 | 102,288 | 127,084 |
| Capital & Net Lending | 28,043 | 35,771 | 27,334 | 38,172 | 40,684 |
| **Current Account Surplus/Deficit (-)** | **-3,807** | **-7,577** | **-3,858** | **-3,949** | **-17,046** |
| **Deficit (before grants)** | **-31,850** | **-43,348** | **-31,192** | **-42,121** | **-57,730** |
| **Financing** | **31,850** | **43,348** | **31,192** | **42,121** | **57,730** |
| Foreign Grants | 6,697 | 7,870 | 8,280 | 8,025 | 8,257 |
| Foreign Borrowings | 11,645 | 19,329 | 7,361 | 9,855 | 11,778 |
| Domestic Financing | 13,508 | 16,149 | 15,551 | 24,241 | 37,696 |
| Non Bank | 13,521 | 16,114 | 17,873 | 30,320 | 36,539 |
| Bank | 257 | 35 | -2,322 | -6,079 | 1,157 |

[15] Central Bank of Sri Lanka: Statistics Department, Economic and Social Statistics of Sri Lanka, p.19

Table 2.9

GDP Ratios[16]

| Item | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|
| **Total Revenue (Rs. million)** | **21.1** | **20.4** | **20.2** | **19.7** | **19.0** |
| Tax Revenue | 19.0 | 18.3 | 17.9 | 17.2 | 17.2 |
| Non Tax Revenue | 2.1 | 2.2 | 2.2 | 2.5 | 1.8 |
| **Total Expenditure & Net Lending** | **31.0** | **32.1** | **27.5** | **28.1** | **29.0** |
| Recurrent | 22.3 | 22.5 | 21.1 | 20.5 | 22.0 |
| Capital & Net Lending | 8.7 | 9.6 | 6.4 | 7.6 | 7.0 |
| **Current Account Surplus/Deficit (-)** | **-1.2** | **-2.0** | **-0.9** | **-0.8** | **-2.9** |
| **Deficit (before grants)** | **-9.9** | **-11.6** | **-7.3** | **-8.4** | **-10.0** |
| **Financing** | **9.9** | **11.6** | **7.3** | **8.4** | **10.0** |
| Foreign Grants | 2.1 | 2.1 | 1.9 | 1.6 | 1.4 |
| Foreign Borrowings | 3.6 | 5.2 | 1.7 | 2.0 | 2.0 |
| Domestic Financing | 4.2 | 4.3 | 3.7 | 4.9 | 6.5 |
| Non Bank | 4.1 | 4.3 | 4.2 | 6.1 | 6.3 |
| Bank | 0.1 | -- | -0.5 | -1.2 | 0.2 |

[16] Central Bank of Sri Lanka: Statistics Department, Economic and Social Statistics of Sri Lanka, p.19

### 2.1.3 *Economic Policy*

Sri Lanka's economic performance was mediocre in the decades after independence. Growth was modest, the unemployment rate was high and the balance of payments weak. Emphasis was laid on social programs—health and education—which, while desirable, diverted resources from the encouragement of productive activity. Little progress was made towards reducing dependence on the three traditional exports[17].

The situation worsened during the 1970-77 period when the United Front government led by the Sri Lanka Freedom Party (SLFP) was in power; private enterprise was restricted and large parts of the economy were nationalized, including much of the plantation sector. Bureaucracy increased, as did patronage and corruption, while economic performance declined further.

The Jayawardene government, reversing the policies of its predecessor, introduced a liberal, open economic policy aimed at creating conditions for sustained economic growth, higher employment, and a shift in resources from consumption into investment. Early measures included the abolition of import restrictions, the easing of price controls, a cutback in food subsidies, the opening up to the private sector of areas previously reserved for the public sector, and active encouragement of foreign investment. These measures were coupled with a massive increase in public investment. A public investment construction boom, whose centerpiece was the Mahaweli Development Program—a huge power, irrigation, and agricultural development and settlement project—fueled GDP growth at an annual average rate of 6% in the period 1978-83, more than double the 2.9% achieved in the previous seven years (1971-77).

While the reforms introduced since 1977 were successful in boosting growth, development, and investment, the economy was still hampered by excessive bureaucracy and state involvement. Around 50% of industry remained in the public sector and two large state corporations: the Janatha Estates Development Board and the State Plantations Corporation accounted for approximately two-thirds of tea

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[17] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.13

production, 32% of rubber, and 10% of coconut. Returns on public investment projects were low. Government and semi-government institutions accounted for over a fifth of total employment; the civil service was generally considered to be overstaffed although underpaid although salaries were substantially upgraded in 1988 and 1993. Government revenue and expenditure were 22% and 32% of GDP—higher proportions than in most developing countries. Finally the tax system, despite considerable simplification, remained complex and counterproductive.

In 1989 a new and rigorous liberalization program was introduced by the former United National Party (UNP) government, the main elements of which have been retained by the new People's Alliance administration. This privatization program will be discussed in more detail in subsequent chapters.

The ethnic conflict has had only a limited effect on the Sri Lankan economy since the main fighting has been in the north and east, away from the economic heartland of the south and west. Apart from the tourism sector, which was badly hit in the late 1980s, the main impact at that time was probably the drying up of foreign investment flows, especially in the north and east. More crucially, the disturbances inspired by the Janatha Vimukthi Peramuna (JVP, or People's Liberation Front) in 1988-89 had a serious effect on the economy because the organization's sphere of operation was close to the country's economic heartland. Nevertheless, after the JVP was crushed at the end of 1989 growth picked up.

As the war in the North and East has dragged on into the 1990s, the government has had to spend increasing amounts of scarce foreign exchange on buying costly armaments. The crowding out of productive investment due to high interest rates brought about by heavy domestic borrowing by the government is estimated to be billions of dollars. The economy is also adversely affected by the high rates of return foreign investors demand because of the general uncertainty in the country.

## 2.2 The Energy Sector

The International Energy Agency (IEA), published the following energy indicators on Sri Lanka, in its 1989-1990 Report on Energy Statistics and Balances of Non-OECD countries:

Table 2.10[18]

| | 1983 | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 |
|---|---|---|---|---|---|---|---|---|
| Tot. Primary Energy Supply (Mtoe) | 1.590 | 1.497 | 1.405 | 1.453 | 1.548 | 1.401 | 1.529 | 1.621 |
| Oil requirements (Mtoe) | 1.485 | 1.316 | 1.197 | 1.225 | 1.361 | 1.178 | 1.301 | 1.351 |
| Electricity generated (GWh) | 2114 | 2261 | 2464 | 2652 | 2707 | 2799 | 2858 | 3150 |
| Population (Millions) | 15.42 | 15.60 | 15.84 | 16.12 | 16.36 | 16.59 | 16.81 | 17.00 |
| GDP (Billion 1985 $US) | 5.55 | 5.54 | 6.08 | 6.35 | 6.39 | 6.57 | 6.71 | 7.13 |
| TPES/GDP (Toe per 000 $US) | 0.29 | 0.27 | 0.23 | 0.23 | 0.24 | 0.21 | 0.23 | 0.23 |
| TPES/Pop. (Toe per capita) | 0.10 | 0.10 | 0.09 | 0.09 | 0.08 | 0.09 | 0.09 | 0.10 |
| Oil Req./GDP (Toe per 000 $US) | 0.27 | 0.24 | 0.20 | 0.19 | 0.21 | 0.18 | 0.19 | 0.19 |
| Oil Req./Pop. (Toe per capita) | 0.10 | 0.08 | 0.08 | 0.08 | 0.08 | 0.07 | 0.08 | 0.08 |
| Elec. gen./GDP (kWh per $US) | 0.38 | 0.41 | 0.41 | 0.42 | 0.42 | 0.43 | 0.43 | 0.44 |
| Elec. gen./Pop. (kWh per capita) | 137 | 145 | 156 | 165 | 165 | 169 | 170 | 185 |

The Central Bank Report published the following data about fuel import quantities and prices in its 1994 annual report (the data is presented in Table 2.11):

[18] International Energy Agency, Energy Statistics and Balances of Non-OECD Countries 1989-1990, Publications Service, OECD (Paris, France: 1992), p.251

Table 2.11[19]

| Item | Unit | 1993 | % Change over 1992 | 1994 | % Change over 1993 |
|---|---|---|---|---|---|
| Quantity of Exports | MT | 589,929 | 46.0 | 611,791 | 3.7 |
| Value of Exports | Rs. Million | 3,801.0 | 37.2 | 3,958.9 | 4.2 |
| Quantity Exported | | | | | |
| Crude Oil | MT | 1,799,597 | 38.8 | 1,897,629 | 5.4 |
| Refined Products | MT | 294,090 | -55.5 | 288,328 | -2.0 |
| L.P. Gas | MT | 37,560 | 19.7 | 50,193 | 33.6 |
| Value of Imports (C&F) | | | | | |
| Crude Oil | Rs. Million | 11,222.37 | 46.4 | 11,407.45 | 1.6 |
| Refined Products | Rs. Million | 2,553.63 | -53.8 | 161.24 | -4.2 |
| L.P. Gas | Rs. Million | 545.00 | 10.0 | 704.00 | 29.2 |
| Average Price of Crude Oil (C&F) | Rs. /Barrel | 842.71 | 4.9 | 806.11 | -4.3 |
| | US$/Barrel | 17.47 | -4.6 | 16.31 | -6.6 |
| Local Sales | | 1,417,712 | -4.6 | 1,567,918 | 10.6 |
| Super Petrol | MT | 172,812 | 4.8 | 183,680 | 6.3 |
| Auto Diesel | MT | 666,513 | 9.9 | 727,923 | 9.2 |
| Heavy Diesel | MT | 18,020 | -85.6 | 53,902 | 199.1 |
| Super Diesel | MT | 23,216 | 2.2 | 24,274 | 4.6 |
| Kerosene | MT | 191,629 | 1.2 | 206,929 | 8.0 |
| Furnace Oil | MT | 219,918 | -12.6 | 228,345 | 3.8 |
| Aviation Turbine Fuel | MT | 72,563 | -11.0 | 78,443 | 8.1 |
| Aviation Gas | MT | 164 | -12.8 | 165 | 0.6 |
| L.P. Gas | MT | 52,877 | 18.3 | 64,257 | 21.5 |
| Local Price | | | | | |
| Super Petrol | Rs./liter | 35.00 | 6.1 | 35.00 | – |
| Auto Diesel | Rs./liter | 12.20 | 4.7 | 11.40 | -6.6 |
| Heavy Diesel | Rs./liter | 11.60 | 4.0 | 10.70 | -7.8 |
| Super Diesel | Rs./liter | 15.00 | 3.1 | 14.20 | -5.3 |
| Kerosene | Rs./liter | 11.80 | 34.1 | 9.50 | -19.5 |
| Bitumen | Rs./liter | 15.15 | – | -15.15 | – |
| L.P. Gas | Rs./kg | 20.00 | 20.9 | 19.23 | -3.9 |

19 Central Bank of Sri Lanka: Statistics Department, Economic and Social Statistics of Sri Lanka, p.66

### 2.2.1 *Energy Supply*

The main sources used to provide energy needs in Sri Lanka are petroleum products, fuelwood and other types of biomass, and hydro-electricity. The relative proportions of these sectors are summarized in the table below:

Table 2.12[20]

| | MTOE | Percentage Share |
|---|---|---|
| Fuelwood and other biomass resources | 4.642 | 70.92 |
| Petroleum products | 1.230 | 18.79 |
| Hydro-electricity | 0.672 | 10.27 |
| Coal and coal products | 0.001 | 0.02 |
| Total | 6.545 | 100.00 |

Fuelwood and other biomass resources

According to national sources, 70% (about 5 million tons of oil equivalent) of the island's total energy is provided by firewood, agricultural residues and animal waste mostly for household use[21]. The biggest share of the biomass (inclusive of fuelwood) usage is in the domestic sector (83%), and the industrial sector uses most of the balance (17%). Sri Lanka has no coal, and its only indigenous energy source, apart from firewood and biological sources, is hydropower.

Petroleum products

Oil, all of which is imported, though much of it is refined domestically, is the largest source of commercial energy supply. However, the country's hydroelectric generating capacity has expanded in recent years, and hydropower accounted for 29% of commercial needs in 1990. Oil imports accounted for 7.7% of total imports in 1993[22].

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[20] Perera, K.K.Y.W, Energy Status in Sri Lanka: Issues, Policy and Suggestions, Institute of Policy Studies (Colombo, Sri Lanka: March 1992), p.5

[21] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.24

[22] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.24

Hydro-electricity

Sri Lanka's electricity sector, (and hydro-electricity in particular) will be discussed in the next chapter.

### 2.2.2 *Energy Demand*

Energy demand in Sri Lanka can be divided into the following sectors: (1) industry and agro-industry; (2) transport; (3) household and agriculture; (4) and government, commercial, and others.

(1) Industry and Agro-industry

The industrial sector accounts for more than 50% of the electricity, about 33% of the petroleum, and about 25% of the fuelwood used in the country. In 1990, eighteen large organizations in the public sector accounted for more than 35% of total electricity sales, while 10 large companies accounted for over half of the sector's petroleum consumption. Fuelwood remains an important source of energy for agro-industry in rural areas[23].

(2) Transport

The transport sector which depends entirely on petroleum products for energy, accounts for more than half of the total demand for these products. Diesel, the predominant transport fuel, contributed toward 75% of total petroleum sales. This figure reflects the extensive public transport network, and the government policy of pricing diesel well below gasoline. As a result of the latter price differential, the proportion of diesel car registration rose dramatically. To reverse this trend, the

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[23] Munasinghe, Mohan, Energy Analysis and Policy, Butterworth and Co (Publishers) Ltd. (Cornwall, United Kingdom: 1990), pp.78-79

government raised the price of diesel to 60% the price of gasoline in 1980, and increased the license fees of diesel cars to three times that of gasoline cars[24].

(3) Household and Agriculture

While Sri Lanka's per capita energy consumption of 0.1 tons of oil equivalent (toe) per capita[25] is low by international standards, and most households use energy only for cooking and lighting, the energy requirements in the household sector account for nearly half of the country's primary energy consumption. The bulk of household energy requirements are still met by fuelwood. Only 13% of households have access to electricity, and the consumption of kerosene, which is mainly used for lighting, has been declining over the past decade in response to increasing prices[26]. The demand for energy in the household/agricultural sector will continue to grow with the increase in population and the rising standards of living.

(4) Government, Commercial, and Others

This sector consumes about 1% of the total demand of energy in the economy.

### 2.2.3 *Energy Policy*

Government Agencies Responsible for Energy Policy

The broad energy sector falls under the jurisdiction of several government agencies and corporations.

The Ceylon Electricity Board (CEB), a statutory corporation under the Ministry of Power and Energy, is responsible for all aspects of electric power from investment to distribution. The Mahaweli Ministry, and its subsidiary body, the Mahaweli Authority

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24 Munasinghe, Mohan, Energy Analysis and Policy, pp.78-79
25 International Energy Agency, Energy Statistics and Balances of Non-OECD Countries 1989-1990, p.251
26 Munasinghe, Mohan, Energy Analysis and Policy, pp.78-79

(MA), also have some responsibility in electricity generation, especially in the case of hydroelectric power.

The Ceylon Petroleum Corporation (CPC), under the Ministry of Industries and Scientific Affairs, is responsible for the nation's petroleum supply. Until 1993 the CPC was the state oil company responsible for importing, refining, and distributing all petroleum products except liquefied petroleum gas (LPG), which is marketed by Colombo Gas and Water Company (also state-owned). In 1993 certain marketing and distribution activities of CPC were privatized, and in 1994 a 51% stake in its lubricants subsidiary was sold[27].

Fuelwood is under the jurisdiction of the Ministry of Land and Land Development and its subsidiary body, the Forest Department (FD). The Natural Resources, Energy and Science Authority (NARESA) is responsible for "overall science and energy policy and research and development"[28].

Until mid-1982 inadequate coordination among the various ministries and agencies involved in different energy subsectors was a major barrier to effective integrated energy planning. Recognizing this problem, the government established an effective organizational framework for overall energy coordination and integrated national energy planning during the period 1982-1984. In 1982 President Jayawardene set up an Energy Coordinating Team (ECT), under a senior energy advisor. Its objective was to coordinate and facilitate the work of relevant ministries and existing agencies, prevent duplication of effort, supplement weak or neglected areas in the energy sector, and provide direct advisory inputs to the President.

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[27] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.24

[28] Munasinghe, Mohan, Energy Analysis and Policy, p. 79

## Recent Government Initiatives in the Energy Sector

Under the leadership of the ECT, a number of urgently needed steps were taken. These included the preparing of a national energy strategy (NES), and implementing programs such as the national energy demand management and conservation program (NEDMCP) and the national fuelwood conservation program (NFCP).

The government has taken some measures to diversify its sources of power generation because with the completion of the Mahaweli project much of the country's potential hydroelectric capacity has been tapped. To meet increasing demand, the government has decided to turn to coal, and an agreement has been reached to build Sri Lanka's first coal power plant at Trincomalee, in the Eastern Province. A Canadian consortium is supplying the plant which will generate 300 MW of power an year, on a build-operate-transfer basis. Several diesel plants are also planned. More details about this process will be provided in subsequent chapters. In addition, the CPC is also currently implementing a major development project to increase the output of diesel, bitumen, and LPG, as well as to increase its storage capacity. The search for oil continues at a low level; two new exploration contracts were signed in 1990 and 1991.

## Energy Policy Guidelines

A draft of Energy Policy Guidelines was initially prepared by the Ministry of Power and Energy during 1984. This was thereafter studied by NARESA and submitted with slight modifications to the President in 1985. The finally approved policy guidelines are as follows:

1. Providing the basic human energy needs.
2. Choosing the optimum mix of energy resources to meet energy requirements at the minimum cost to the national economy.
3. Optimizing of available energy resources (hydro-electricity, biomass, solar, wind and petroleum) to promote socio-economic development.

4. Conserving energy resources and eliminating wasteful consumption in the production of energy and the use of energy.
5. Developing and managing forest and non-forest wood fuel resources.
6. Reducing dependence on foreign energy resources and diversifying the sources of energy imports.
7. Adopting a pricing policy which enables the financing of energy sector development.
8. Ensuring continuity of energy supply and price stability.
9. Establishing the capability to develop and manage the energy sector.

### 2.2.4 *Policy Recommendations*

Given Sri Lanka's precarious balance of payments position, its absence of fossil fuels, and the critical fuelwood situation, many measures should to be taken to revitalize its energy sector. Indeed, in several areas, useful policy initiatives have already been launched. Increasing the efficiency of energy use, pricing energy more efficiently, and reducing the country's vulnerability to energy shocks are among the main policy goals which should be further pursued[29].

Increasing the Efficiency of Energy Use

Sri Lanka lacks indigenous fossil resources, and for the next few decades the bulk of its incremental energy must come from imported fossil fuels. Without a sustained effort to maximize the efficiency of fossil fuel use, the country's development objectives will inevitably be compromised. Furthermore, available domestic resources must be utilized more effectively. The bulk of the population still depends on fuelwood for basic energy needs, and inefficient use of this resource will result in catastrophic long-term

[29] Munasinghe, Mohan, Energy Analysis and Policy, p. 84

consequences. Therefore, the national energy demand and conservation program (for commercial fuels), and the national fuelwood conservation program (for improved domestic cooking stoves), must be expanded rapidly and pursued vigorously by the relevant task forces.

Efficient Pricing

Recent changes in both electricity and oil prices have brought average commercial fuel prices close to economically-efficient levels. These favorable trends must be maintained to ensure good demand management. While average prices are reasonable, some petroleum product prices need to be further revised. The price of kerosene and diesel fuel relative to that of gasoline, for example, should be changed.

Reducing the Vulnerability to External Shocks

Over the past decade Sri Lanka has experienced numerous external shocks which have affected both the energy sector and the economy as a whole. These include the two oil shocks of the 1970s and the 1983-1984 drought. In order to reduce this vulnerability, the government should diversify both the type and source of energy by measures such as purchasing petroleum products and crude oil from a variety of sources and exploring alternative domestic sources of electricity generation. The renewable technologies which were discussed earlier are particularly important in this context.

### 2.2.5 *Outlook for the Future*

On the whole, the prospects for Sri Lanka to provide for its growing energy needs are favorable. The many far-sighted government programs and policies of the 1980s have put the nation on a path toward achieving this goal. It is important, however, that these initiatives be continued by successive regimes, and that the political process does not hinder careful planning in the energy sector.

As the country develops, the mix of energy use will gradually change. The fuelwood component is expected to become less important while the consumption of more versatile, efficient sources such as electricity will increase dramatically. In subsequent chapters I will explore the structure and future requirements of this important sector: so vital to Sri Lanka's transition to a middle-income economy.

# CHAPTER 3

## Sri Lanka's Power Sector

Sri Lanka's electricity demand increased rapidly in the 1980s as a result of the growth introduced by the government's economic liberalization policies. The country's projected economic and social development and the rapid growth of its industrial sector will place additional demands on its power sector. The adequate provision of this vital infrastructure service has become a major challenge for the new People's Alliance government as it charts the development course of the nation.

### 3.1 The Evolution of Sri Lanka's Power Sector

Sri Lanka's electric power sector was initially a mix of private and municipal generating systems with localized distribution networks operating in isolation. The gradual development of a national grid and the construction of large hydroelectric power stations led to the centralized ownership and management of the system by a single utility by the 1950s.

Initially, the national generation and transmission system, together with some of the distribution networks, were owned and operated by the Department of Government Electrical Undertakings (DGEU). The DGEU was transformed into the Ceylon Electricity Board (CEB) in 1969. However, until about 1984, the distribution of electricity in most local authority (City and Village Councils) areas was owned and managed by the respective councils. There were over 200 such bulk purchasers from the CEB for retail sales, mostly to households[1].

[1] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 1, Institute of Policy Studies (Colombo, Sri Lanka: December 1994), pp.1-4

Since 1969, the CEB has continued to further develop the distribution network, expanding into areas which were not covered by the local authority networks. By 1982, nearly 70% of the nation's electricity was sold directly by the CEB. The distribution networks managed by the local authorities became increasingly outdated, with the rapid expansion of population and increased commercial activity in urban areas. Furthermore, most of the local systems were poorly managed, and hence resulted in loss of revenue to both the councils and the CEB. The technical performance of most of the networks were also well below national standards, and were plagued with problems such as poor voltage regulation, excessive energy losses, and poor reliability. All major towns were supplied by such local authority networks except Colombo, which had been transferred to the CEB several decades ago.

In 1983, the government formed the Lanka Electricity Company (LECO), jointly owned by the CEB and the Urban Development Authority (UDA), with the objective of transferring ownership of distribution networks from the local authorities to this new company. Both CEB and LECO acquired the local authority networks according to an agreed program; by 1993 LECO had acquired 30 local authority networks while the CEB took over the remainder. Except for the city of Kandy, the town of Beruwela, and the councils in the North and East, all other networks had been taken over by 1993. LECO concentrated on the councils in the more populous coastal areas of the Western and Southern Provinces, while the CEB was entrusted with the remaining networks, mostly in the interior of the country.

The generation and transmission system continued to be developed, owned, and operated by the CEB. Currently, the share of electricity directly sold by the CEB exceeds 80%[2]. The networks taken over by both LECO and CEB have mostly been rehabilitated with loan facilities from the Asian Development Bank (ADB).

### 3.2 Multi-Purpose Irrigation and Power Generating Schemes

A large proportion of Sri Lanka's hydroelectric resources have been developed as part of large multi-purpose projects which provide not only irrigation and power, but facilities for inland fishery, industry, and tourism. At present, there are three such projects: the Gal Oya Scheme, the Uda Walawe Reservoir Project, and the Mahaweli Development Program[3].

The third of these projects, which is constructed on the Mahaweli river (the longest river in the island), is by far the most ambitious multi-purpose irrigation development project undertaken by the government. Originally, it was to be completed over a period of 30 years. But, in 1977, the government decided to accelerate the Development Program and implement as much of it as possible during a six year period. The "Accelerated Mahaweli Program" (AMP) as it came to be called, is based on the master plan jointly prepared by UNDP/FAO, and local authorities. The AMP was started in 1977 with financial assistance from friendly donor countries, such as the UK and Canada, and consists of the following major projects: Maduru Oya, Victoria, Kotmale, and Randenigala and Rantambe. Reservoir parameters of the specific projects are given in Appendix 1.

The AMP provided irrigation facilities to 265,000 hectares of new land, improved irrigation facilities to 100,000 hectares of existing land, produced an energy output of 2032 GWh annually, and increased the installed capacity by 660

[2] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 1, pp. 1-4
[3] Central Bank of Sri Lanka, Sri Lanka: An Economic, Financial and Investment Guide, p.64

MW. With these developments, installed hydro capacity was more than doubled while land under irrigation was increased by more than 70%[4].

### 3.3 The Present Power Generating System

The electricity generating system in Sri Lanka has rapidly developed since the implementation of the Kelani River hydroelectric system in the 1950s. Presently, there are 15 grid-connected hydroelectric generating stations and 3 medium sized thermal generating stations in operation. Hydroelectric potential in the three major rivers— Mahaweli, Kelani, and Walawe—for the most part has been developed, but more potential remains on those rivers as well as on the other major river basins.

The total generating capacity is 1410 MW and the expected generation from the combined hydro-thermal system is 4364 GWh/yr. In this estimate, the generation figures for hydro are calculated assuming average hydrological (rainfall) conditions, while thermal plants have been assumed to operate under the maximum possible number of hours, allowing sufficient time for maintenance and unplanned outages. Electricity demand in the year 1994 was 4363 GWh and the maximum demand was 911 MW. Thus, the present generating system has an apparent excess capacity of 474 MW and 1053 GWh/yr of energy[5].

Yet, the apparent excess capacity and energy are of little significance for a predominantly hydroelectric generating system like that of Sri Lanka, because there are seasonal variations of hydro availability and restrictions in water releases owing to irrigation demands. If the wettest year in recent history (1971) occurs again, the system should provide 4500 GWh/yr; if the driest year (1983) occurs again, hydro energy will only be 2545 GWh/yr[6]. The overriding operating constraint on the

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[4] Central Bank of Sri Lanka, Sri Lanka: An Economic, Financial and Investment Guide, p.64
[5] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, Institute of Policy Studies (Colombo, Sri Lanka: December 1994), p.3
[6] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.6

system is minimizing thermal electricity generation, which increases operating costs and complicates the planning process.

Table 3.1

Existing Generating Stations[7]

| Generating Station | River/catchment Area | Year Commissioned | Rated Capacity (MW) | Expected Energy (GWh/yr) |
|---|---|---|---|---|
| 1. Laxapana | Kelani | 1950<br>1958 | 25<br>25 | 289 |
| 2. Wimalasurendra | Kelani | 1965 | 50 | 112 |
| 3. Polpitiya | Kelani | 1969 | 75 | 427 |
| 4. New Laxapana | Kelani | 1974 | 100 | 491 |
| 5. Canyon | Kelani | 1983<br>1988 | 30<br>30 | 161 |
| **SUB TOTAL** | **Kelani** | | **335** | **1480** |
| 6. Ukuwela | Mahaweli | 1976 | 38 | 177 |
| 7. Bowatenna | Mahaweli/Sudu Ganga | 1981 | 40 | 53 |
| 8. Victoria | Mahaweli | 1984-86 | 210 | 726 |
| 9. Kotmale | Mahaweli | 1985-88 | 201 | 482 |
| 10. Randenigala | Mahaweli | 1986 | 122 | 378 |
| 11. Rantambe | Mahaweli | 1990 | 49 | 216 |
| **SUB TOTAL** | **Mahaweli** | | **660** | **2032** |
| 12. Inginiyagala | Irrigation Reservoir | 1963 | 11 | 27 |
| 13. Uda Walawe | Irrigation Reservoir | 1969 | 6 | 8 |
| 14. Nilambe | Mahaweli | 1988 | 3 | 12 |
| **SUB TOTAL** | **Small Hydro** | | **20** | **47** |
| 15. Samanalawewa | Walawe | 1993 | 120 | 357 |
| **SUB TOTAL** | **All Hydro** | | **1135** | **3916** |
| 16. Kelenitissa Steam | Furnace Oil | 1962-63 | 50 | 312 |
| 17. Kelenitissa Gas Turbine | Heavy Diesel | 1980-82 | 120 | 749 |
| 18. Sapugaskande diesel | Residual Oil | 1984 | 80 | 439 |
| **SUB TOTAL** | **All Thermal** | | **250** | **1500** |
| TOTAL | **All Stations** | | **1385** | **5416** |

[7] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.9

### 3.4 Electricity Output and Consumption

The following tables indicate how electricity is generated and consumed in Sri Lanka. The first table gives the hydroelectric and thermal components of power generation in the Sri Lankan system. The second one gives an indication of how this power is consumed among the various sectors. More details about these issues are given in the charts and tables after the appendices, where the actual figures are tabulated, and the data are presented graphically.

Table 3.2

Hydro and Thermal Components of the Sri Lankan System[8]

| | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|
| **Installed Capacity (MW)** | **1,241** | **1,290** | **1,290** | **1,410** | **1,410** | **1,410** |
| Hydroelectric | 968 | 1,017 | 1,017 | 1,137 | 1,137 | 1,137 |
| Thermal | 272 | 272 | 272 | 272 | 272 | 272 |
| **Power Generated (GWh)** | **2,858** | **3,149** | **3,377** | **3,540** | **3,979** | **4,364** |

Table 3.3

Utilization of Electric Power in Sri Lanka[9]

| | 1989 | 1990 | 1991 | 1992 | 1993 | 1994 |
|---|---|---|---|---|---|---|
| **Power Sold (GWh)** | **2,347** | **2,608** | **2,742** | **2,916** | **3,270** | **3,582** |
| Domestic | 421 | 514 | 644 | 704 | 826 | 933 |
| Commercial | 441 | 509 | 547 | 581 | 641 | 593 |
| Industrial | 844 | 910 | 958 | 1,058 | 1,223 | 1,404 |
| Local Authorities | 624 | 657 | 572 | 545 | 536 | 612 |
| Street Lighting | 17 | 18 | 22 | 29 | 43 | 40 |

[8] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.25
[9] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.25

### 3.5 Characteristics of the System

Technical

The technical characteristics of the Sri Lanka power generating system and their expected patterns of change are of primary concern to both system planners and private developers.

*Reserve Margin*

This factor, which indicates the extra megawatt capacity available in the power generating system after meeting the maximum demand of the consumers, was 74.1% in 1993. It is usual for a predominantly hydroelectric system to have a high reserve margin because the generator megawatt rating usually caters to between 2 to 3 times the average river flow.

For a predominantly hydroelectric system like that of Sri Lanka, the reserve margin does not convey any idea about the reliability of the generating system. This is because the generating system is energy (fuel)-constrained and not capacity-constrained. This situation will change and the reserve margin will drop steadily in the future as the Sri Lankan system moves towards the mixed hydro-thermal system, which is expected in the future. The reserve margin is expected to drop from 74% in 1993 to 18% in 2006, when thermal sources will account for about 52% of generation[10].

*Spinning Reserve*

The spinning reserve is the additional capacity of generation available to be immediately loaded if the system demand suddenly increases, or if one or more generators trip out due to a malfunction. In Sri Lanka's generating system, the

[10] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.20

spinning reserve is usually kept at a low level because of the high proportion of hydro generators, which can be started at very short notice in the event of an unexpected shortfall. By contrast, countries that have a predominantly thermal system where coal, oil, or nuclear plants carry the base load, usually maintain a higher spinning reserve, of the order of about 15%, because large thermal generating plants require longer start-up times[11].

It is expensive to maintain spinning reserve because the generators which not fully loaded (because of this requirement) usually operate at poor efficiency levels.

*System Stability*

Unlike most other energy sources, such as petroleum products, electricity cannot be stored in large quantities. However, consumers require electrical energy at a flip of a switch. Since electricity must be generated at the same moment it is needed, this requires that the electrical energy system always be in dynamic equilibrium. In other words, the energy input to the system in the form of water at high elevation, and as fuel fed into thermal stations, should be exactly equal to the energy demand of all consumers at that instant plus all energy losses (in the conversion, transmission and distribution systems).

If the demand on power stations is too high, their generators will accelerate beyond their safe limits, and their automatic protection systems will trip them out of the system to prevent damage. This response causes a further deficit in generation, placing heavy demand on the remaining generators in the system. Unless there is excess capacity and enough fuel (especially water), this process may even lead to a total system blackout.

[11] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.21

For the system stability to be maintained in such emergency situations, it is desirable that no single generator carries a disproportionate share of the system load. A rule of thumb used in the industry (in Sri Lanka), specifies that no single generator should deliver more than 10% of the load (although more rigorous methods are available to determine this factor more accurately). In the present Sri Lankan system the largest single generating station is the 70 MW one at Victoria. Since the system demand varies between 350 MW and 911 MW, if Victoria operates at peak time, it is within the 10% limit, but it would violate this rule during off-peak hours[12]. Although adherence to the 10% limit throughout the day will yield higher reliability levels, unfortunately, these system dynamic stability considerations do not always coincide with the economics of power generation. For example, it would be economical to add a coal-fired generator of 150 MW in the year 2000, when the system's peak demand is expected to be only 1371 MW, although this will cause the 10% rule to be violated all the time, throughout the day[13].

The relative locations of the generating plants and the load centers are also important for stability. A large generator, feeding the load center through a long transmission line, is generally not favored because long overhead transmission systems are more liable to be affected by lightening, birds, and sabotage, than are shorter ones.

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[12] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.23

[13] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.23

*Energy Losses in Transmission and Distribution*

The following table indicates the huge energy losses in the Sri Lankan system despite efforts made to reduce them.

Table 3.4[14]

| | 1984 | 1985 | 1986 | 1987 | 1988 | 1989 | 1990 |
|---|---|---|---|---|---|---|---|
| Losses in T&D (GWh) | 374.7 | 391.4 | 409.3 | 441.3 | 414.2 | 505.9 | 541.6 |
| Losses as a percentage of generation | 16.6 | 15.8 | 15.4 | 16.3 | 14.8 | 17.7 | 17.2 |

## 3.6 Electricity Tariffs

Electricity tariffs were revised by the CEB on two occasions in 1994. In February, tariff rates applicable to the domestic category were raised within a range of 1 percent to 183 percent, depending on the level of consumption. Tariffs in other categories rose by about 30 percent. However, in May 1994, the tariff rate on the first 100 units in respect to the domestic category was brought down to the level that prevailed in July 1993, reducing the rates by a range of 29 percent to 65 percent. Consequent to these tariff revisions, the average tariff rate per unit increased by 39 percent to Rs. 3.68 in 1994, from Rs. 2.64 in 1993. The revised electricity rates and the previous rates are shown in Table 3.5.

[14] Perera, K.K.Y.W, Energy Status in Sri Lanka: Issues, Policy and Suggestions, p.162

Table 3.5[15]

| Category | Previous Rate (Rs./kWh) | With Effect from 07/93 (Rs./kWh) | With Effect from 05/94 (Rs./kWh) |
|---|---|---|---|
| **Domestic Purposes** | | | |
| Units 0-10 | 0.60 | | 0.60 (0-10 units) |
| 11-50 | 1.20 | 1.70 (0-60 units) | 1.20 (11-50 units) |
| 51-100 | 2.40 | | 2.40 (51-100 units) |
| 101-450 | 3.90 | 4.40 (61-180 units) | 4.40 (101-180 units) |
| >450 | 5.20 | 5.25 (>180 units) | 5.25 (> 180 units) |
| **Industrial Activities** | | | |
| Small | 3.05 | 4.00 | 4.00 |
| Medium | 2.90 | 3.80 | 3.80 |
| Large | 2.80 | 3.65 | 3.65 |
| **General Purposes** | | | |
| Small | 4.05 | 5.30 | 5.30 |
| Medium | 4.00 | 5.20 | 5.20 |
| Large | 3.85 | 5.00 | 5.00 |
| **Hotels** | | | |
| Small | 4.05 | | |
| Medium | 4.00 | Same as before | Same as before |
| Large | 3.85 | | |

Note:

*Small*: Supply of electricity at 400/230 volts and contract demand is less than 50KVA.

*Medium*: Supply of electricity at 400/230 volts and contract demand is equal or more than 50KVA

*Large*: Supply of electricity at 11KV, 33KV and 132 KV

Time of Day Tariff is applicable only to the industrial and hotel categories. Peak rates and off-peak rates were revised upward by 30-31 percent. From February, 1994 onwards the industrial sector tariff is applicable to hotels

[15] Central Bank of Sri Lanka, Annual Report 1994, (Colombo, Sri Lanka: April 1995), p.67

Pricing Distortions

The many cross subsidies and other pricing distortions in the system are important to both CEB planners and potential independent power producers. Some of these include[16]:

(a) Cross subsidies between households in low and high consumer groups. This is equivalent to a cross subsidy between the interior provinces which have a high share of lower bracket consumers and the western coastal belt which has more affluent customers.

(b) The highly dispersed nature of household consumers in the interior provinces causes higher network losses and maintenance costs thus adding to the total cost of providing electricity to these areas.

(c) Low-consuming households demand electricity at the peak hours of 6-8 p.m., at which time the generating cost is highest, a further reason supplying power to them is extremely expensive.

(d) The irrational tariff policy of the CEB has also distorted the price of electricity.

(e) Finally, the lack of true decentralization of the existing system, as well as the lack of clear identification of transfer prices from generation and transmission to the provinces has made it difficult for the CEB to make proper estimates of the costs effectiveness of various portions of the network.

## 3.7 Expected Demand Growth

The average annual demand growth for the 20-year period from 1972 to 1992 was 6.8% per year. However, this figure includes periods of relatively high growth (8% per year from 1978-83) and those of low growth (4% per year from 1972-77). This irregular demand pattern has various economic, social, and political causes, but

[16] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 1, p.6

it can be attributed mainly to the changing structure of demand (among regions) and to changes in energy intensities within the different sectors of the economy.

The expected future growth of electricity is extremely difficult to predict. While econometric and time trend analyses are useful for the overall development of the forecast, they ignore many important but unpredictable factors (such as radical government policy changes, and developments in the global economy), which may drastically affect the results. In 1994 the forecast which the CEB used for its investment planning work predicted an annual average electricity demand growth rate of 7.9% in the long term (20 years). It also estimated that the energy losses in the transmission and distribution system, which are presently about 18% of generation, would be reduced to 12% by 2004, and the system load factor (the technical parameter specifying the ratio between the maximum load and the average load) would improve from the present value of 56% to 58% by the year 2005[17].

## General Planning Methodology

Sri Lanka's predominantly hydroelectric system is difficult to model because irrigation demands usually have priority over generation, and the country has a highly variable rainfall pattern.

Extensive work has been done in the past under various Mahaweli projects, and the CEB's own regular planning studies, to develop and refine the modeling of the cascaded reservoir/power station network, irrigation diversions/releases and the integrated operation of the hydroelectric system with the backup thermal generating system. This modeling process is then used to minimize the combined cost of operating the existing thermal generating plants and investing in and operating new generating plants. Therefore, the planning process adopted is

[17] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.6

designed to meet a specified future demand for electricity at a given reliability level (subject to the constraints of plant construction times and other technical limitations) at minimum cost.

This process differs from a traditional cost-benefit analysis because its aim is to meet the demand for electricity at any cost, subject to declared reliability levels. Sensitivity of demand to cost of electricity is analyzed outside the planning models, and these studies are conducted with a given set of information about plant capital costs and fuel price forecasts[18].

[18] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.7

Table 3.6[19]

Results of CEB's Generation Expansion Planning Studies 1993

| Year | Hydro Additions | Thermal Additions | Thermal Retirement | LOLP% |
|---|---|---|---|---|
| 1994 | | | | 5.678 |
| 1995 | | | | 8.182 |
| 1996 | | Gas Turbine 66 MW<br>Diesel 40 MW (Ext) | | 4.444 |
| 1997 | | Diesel 110 MW | | 0.726 |
| 1998 | | Diesel 40 MW | | 1.794 |
| 1999 | Kukule 70 MW | | | 3.302 |
| 2000 | Upper Kotmale 123 MW | | | 3.025 |
| 2001 | | Coal Trance Unit 1: 150 MW | KPS Oil Steam 2x22 MW | 1.890 |
| 2002 | | Coal Trinco Unit 2: 150 MW | Gas Turbine 3x18 MW (for refurbishment) | 1.659 |
| 2003 | | Refurbished GT 3x20 MW | Gas Turbine 3x18 MW (for refurbishment) | 4.698 |
| 2004 | | Refurbished GT 3x20 MW<br>Coal Trinco Unit 1: 300 MW | Sapu Diesel 2x16 MW | 0.418 |
| 2006 | Gin Ganga 49 MW | Gas Turbine 22 MW | | 4.045 |
| 2007 | | Coal Trinco Unit 2: 300 MW | | 1.069 |
| 2008 | | Gas Turbine 22 MW | Sapu Diesel 2x16 MW | 3.253 |

Total PV cost up to 2013 = US$ 1598.2 million (Rs. 76,711.9 million)

Long term average generation cost = 6.03 US cts./kWh (2.89 Rs./kWh)

[19] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.9

## 3.8 The Future Generating System

The previous table shows the August 1993 least-cost generation expansion plan of the CEB. The immediate and medium-term new plant requirements are expected to be met with diesel generating plants, and 110 MW of diesel as well as 66 MW of gas turbine generating capacity will be added before the year 2000. Kukule is the only feasible hydroelectric project slated for commissioning before the turn of the century. If hydroelectric plants are delayed, other thermal plants would be required. A coal plant at Trincomalee is an economically- and technically-feasible generating option scheduled to be added to the system by 2001. Unfortunately, since financing for the plant has not yet been finalized, it will not be available on schedule given its minimum required construction time of four years.

The figure on the previous page shows the expected hydro-thermal share in the generating system of the future. Uncertainties regarding the plant mix before the year 2000 may alter slightly the pattern of relative shares shown in the diagram. However, it is extremely likely that the power generating system in Sri Lanka will remain a predominantly hydroelectric system until at least the year 2005, when the share of thermally-generated electricity exceeds 50% of the total. In the present planning horizon of the CEB (until 2013), the hydro share in generation is expected to drop to 29% twenty years hence, but will still be large enough to exert a significant influence on the power supply system.

## 3.9 Investment Required in Power Generation

The CEB estimated capital costs for the new generation projects in its generation expansion plan, and calculated that the country would require about US$ 1100 million (in constant 1993 dollars) for investment in power generation between

1994 and 2000. The significant feature about these funds is that 70% will have to be met with foreign exchange[20].

The above costs are for power generating facilities alone. Further investment will be required for transmission as well as distribution system development and rehabilitation. Although I will not discuss these costs here, the CEB has stated that, according to past experience, investment on new transmission and distribution facilities have usually accounted for another 20-40% of the generating costs[21].

### *3.9.1 Past Investments on Power Generation*

Loans and grants from various agencies were the main source of finance for power generation over the last two decades. The degree of participation of CEB in project development and construction varied according to project type. In the case of power projects developed under the Accelerated Mahaweli Scheme, generating stations were handed over to the CEB after construction. However, the recently completed Samanalawewa project was handled entirely by the CEB.

The costs of the projects (even when measured per installed unit of capacity) varied significantly from each other as shown in the table below. This variance is not unusual for hydroelectric projects, because of the vast differences between plant location, reservoir size and capacity, and characteristics of the associated dams.

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[20] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.11
[21] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.11

Table 3.7[22]

Costs of Generating Stations Completed Since 1975

| Project | Commissioning Date | Cost at Completion (Rs. millions) | Financing Source |
|---|---|---|---|
| Ukuwela Hydro | 1976 | 155 | Locally |
| Bowatenna Hydro | 1981 | 293 | OPEC, ADB |
| Victoria Hydro | 1985-86 | 3306 | UK grant |
| Kotmale Hydro | 1988 | 4006 | Swedish grant and Comm. Loan |
| Randenigala Hydro | 1986 | 3500 | Soft Loan |
| Rantambe Hydro | 1990 | 5500 | Germany |
| Kelanitissa Gas Turbines | 1980-82 | 530 | Local and Loans |
| Sapugaskanda Diesel | 1984 | 1066 | IBRD |
| Samanalawewa Hydro | 1992 | 16,516 | UK, Japan Loans |

### 3.9.2 *Cost to the Economy and the Power Sector*

Funds for most of the projects have been secured at nominal interest rates—in some instances as low as 0.75% per year. This factor and the generous grace periods (typically 5 to 10 years before repayment) of many loans resulted in very low costs to the national economy. The government of Sri Lanka has continued to practice a policy of re-lending funds to the CEB at an interest rate of 10% per year[23], while international lending agencies, particularly the World Bank and the Asian Development Bank, have continued to insist that the CEB yield an annual return of 8% on assets.

It is doubtful, however, that the CEB will continue to be able to obtain funds for future projects at the above generous terms, because of a variety of reasons which will be discussed in the next chapter.

[22] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.14
[23] Siyambalapitiya, Tilak, Power Sector Development Issues: Ownership Issues: Part 2, p.14

# CHAPTER 4

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## Financing Future Investments

The means used to finance future investments in power generation will depend on the organization and ownership of the power sector in the near future. The new government elected in August 1994 promised to speed up the nation's privatization program: and the power sector was one of the areas targeted for this effort.

Since the government, however, is concentrating on addressing more immediate problems such as the ongoing ethnic conflict, it has for the most part neglected its election pledge. Although it has set up a Public Enterprise Reform Commission (PERC) to restructure nine state companies and sell off a further ten, no single major privatization initiative has yet been completed. While privatization managers complain that the stock market is too flat to launch new state sell-offs, brokers say the government's lack of economic initiatives, particularly regarding privatization, has been a leading factor in depressing the stock market[1].

The current uncertainty in the whole liberalization effort makes it difficult to predict the outcome of future reforms in the Sri Lankan power sector. Therefore, I will examine several possible ownership scenarios and discuss how the needed US$ 1100 million could be financed under each of them.

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[1] Economist Intelligence Unit, Country Report, 4th Quarter 1995: Sri Lanka, Electronic Publishing Services (London, United Kingdom: 1995), p.11

## 4.1 Possible Ways of Reforming the Sri Lankan Power Generating Sector

The potential for improving performance in power generation in Sri Lanka is substantial. Yet, such amelioration will require three broad actions: applying commercial principles to infrastructure operation, encouraging competition from appropriately-regulated private sector providers, and increasing the involvement of users and other stakeholders in planning, providing, and monitoring of services. Four main options (which implement the above three actions to various degrees) are available for restructuring the power sector:

(1) Public Ownership and Public Operation
(2) Public Ownership and Private Operation
(3) Private Ownership and Private Operation
(4) Community and User Provision

I will only discuss the first two of the above four options in detail because I believe that the third and fourth will not be feasible in the Sri Lankan power generating sector within the time frame I am considering. I will focus mainly on the BOT method of privatization, when discussing "public ownership and private operation," because BOT is feasible in Sri Lanka under certain conditions, and because it is one of the main options currently being considered by the government. More details about the general features of the four options are presented in Appendix 2.

## 4.2 Public ownership and public operation

This option allows the present setup to continue with some minor changes. A number of rapidly developing countries have retained a public ownership structure with varying degrees of success. A case worth examining is the Republic of Korea, which still manages all electricity supply through a single State-owned electricity authority. A very high degree of autonomy, coupled with complete freedom in decision-making has made the Korean Electric Power Co. (KEPCO) one of the most successful state-owned electricity authorities in the world. It has also been able to maintain electricity prices at very competitive rates, a factor which is deemed vital for the rapid development of the its economy.

A similar model may be possible in Sri Lanka, but this would require substantial changes to the current system. In Sri Lanka, the power sector has been traditionally used to implement state policy, particularly rural electrification, largely at the expense of the financial stability of the state-owned utility. Although some electrification projects in Sri Lanka have been financed thorough ADB loans which have been transferred to the CEB, the agency has poured more than Rs. 3000 million (US$ 600 million) over the last 5 years into rural electrification because of direct government requests, usually on an ad-hoc basis[2].

If complete financial and operational freedom is granted to the CEB, it could, theoretically, operate as a fully commercial concern; however, the government would have to provide certain guarantees regarding concessionary financing secured by the CEB from international agencies. This autonomy, coupled with the implementation of financial accountability in the operating units of the CEB (by mechanisms such as transfer prices), should enable the agency to offer electricity at competitive prices to the consumers. In addition, the government should also restructure electricity tariffs, which should be moved progressively from a subsidy-oriented structure to a more market-oriented system.

Within this system, the government may, as done in other countries, continue to oversee the electricity tariff issues, and it would remain the final authority making informed decisions about the essential subsidies to be provided to specific groups of consumers. It probably would have to establish a separate agency, however, to fulfill

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[2] Siyambalapitiya, Tilak, <u>Power Sector Development Issues: Ownership Issues: Part 1</u>, p.7

specific state objectives such as providing electricity to most households by the year 2000.

### 4.2.1 *How the Government Will Raise Funds*

The raising and disbursement of US$ 1100 million between now and the year 2000 is undoubtedly a monumental task for policy makers, financiers, and for the utility itself. In addition to the US$ 1100 million, there will be the required interest payments during construction, cost escalation and inflation—factors which cannot be forecast with much reliability for such a long period into the future.

Unfortunately, capital for such infrastructure development projects may no longer be available in sufficient quantities from the traditional sources of financing such as the international lending institutions, bi-lateral, and multi-lateral agencies as there are increasing demands for scarce capital from the newly re-structured East European economies and from newly liberalized economies such as Vietnam. Therefore, a large proportion of the enormous investment in power, which will be crucial for Sri Lanka's drive for industrialization and its declared social objective of rural electrification by the year 2000—may have to be financed through non-conventional, innovative mechanisms. If the current pattern of state ownership and operation is continued, the government may be forced to obtain the required funds directly from international capital markets.

Tapping International Capital Markets

Several channels exist for tapping international capital markets. The larger private utilities in developing countries have direct access to debt and equity markets. In October 1993, for example, Telecom Argentina placed much of its US$ 500 million, seven-year bond issue with US and Asian investors; and Argentina's Telefonika has also used bond market placements to raise expansion funds[3].

Such foreign direct investment opens another route into international equity markets. General Electric Corporation, an international conglomerate, has an active interest in promoting infrastructure projects within developing countries. Its subsidiary, the General Electric Capital Corporation (GECC), issues securities on US and European markets and invests the funds in selected projects. GECC has participated as an equity investor, for instance, in the Northern Mindanao power project—a 108 MW diesel power project in the Philippines. Backed by the group's total operations, the placement of securities issued by GECC is easier than it would be for developing nations or private groups who try to do so independently.

An instrument widely used to tap resources in the US capital market is the American depository receipt (ADR). ADRs are certificates of deposit that enable foreign companies to raise equity on US markets without the need for a listing on a US stock exchange and without complex settlement and transfer mechanisms. They are issued by a US depository bank, and the underlying shares of the company are held in trust by a custodian bank in the home country. In 1990 Compania de Telefonos de Chile (CTC) raised US$ 92 million on the New York Stock Exchange through an issue of equity in the form of ADRs—the first major equity issue from Latin America in three decades[4].

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[3] World Bank, World Development Report 1994: Infrastructure for Development, p.93
[4] World Bank, World Development Report 1994: Infrastructure for Development, p.93

In April 1990 the US Securities and Exchange Commission approved rule 144a, facilitating private placement of securities, including those placed as ADRs. Before then, privately-placed securities held by qualified buyers (institutions that manage assets worth at least US$ 100 million) could be traded only after a two- or three-year holding period. Rule 144a allows trading to occur immediately, provided that the new buyer is also qualified. Moreover, after three years the securities can be sold to all buyers. Rule 144a was used in 1992 to enable a US$ 207.5 million international bond issue for the Mexican City-Tolcua Toll Road[5]. Since then, other Mexican toll roads and the Subic Bay power plant in the Philippines have raised funds using rule 144a. Therefore, this revision of US securities law has given governments of developing nations another way to raise badly needed capital for infrastructure development.

There are many other private sources of funds available to developing country governments for financing their infrastructure needs. Some of these are presented in Table 4.1:

[5] World Bank, World Development Report 1994: Infrastructure for Development, p.93

Table 4.1[6]

Private Sources of Infrastructure Funds

| Fund | Size; $billion | Investors | Description |
|---|---|---|---|
| Global power investments | 2.5 | GE Capital Corp., Soros Fund Management International Finance Corp. | Invests in power projects |
| AIG Asian Infrastructure Fund | 1.2 | American International Group Inc., Singapore's Temasek Holdings Ltd., Government of Singapore's Investment Corp. | Invests in all types of infrastructure |
| Asian Infrastructure Fund | 1.0 | Peregrine Investments Holdings, George Soros, Frank Russell Co., International Finance Corp., Asian Development Bank | Invests in all infrastructure sectors throughout Asia |
| Inter-privatization fund | 6.0 | Lehman Brothers, KPMG and Russian Partners | Infrastructure in the Soviet Bloc |
| Cons. Electric Power Asia Ltd. | 1.8 | Public Listed Company in Hong Kong | Power stations in Asia |

### 4.2.2 *Limits to Government Finance*

The main advantage of state infrastructure provision is that in most countries the government is the most creditworthy entity and is able to borrow at the lowest rates, making possible projects that might not otherwise be financially viable. Balanced against this advantage has been the difficulty of maintaining accountability (because of the endemic corruption and wastage in the public sectors of many developing nations), leading often to high costs of provision to the consumer. The World Bank gives the following example to illustrate the countervailing benefits and costs of state-sponsored infrastructure provision:

> For a power generation plant, with construction costs accounting for 70% of all costs and a 10% interest rate, construction cost overruns of 20% and delays in construction of two years

[6] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.47

each lead to a 15% increase in unit costs of power produced. The track record for publicly sponsored projects shows that such cost overruns and time delays are common, leading to a cumulative cost increase of about 35%. Compare this with an interest rate advantage for government, which can borrow at, for example, 10% rather than 13% available to private investors. This 3 percentage-point advantage translates into a cost reduction of 20%. In other words, it would take almost a 6 percentage-point interest rate advantage to negate the inefficiencies described[7].

Consumers would undoubtedly benefit if it were possible to combine low interest rates and efficient provision. But the goal of a free lunch may be illusory. Even credit-worthy governments cannot borrow unlimited amounts at low cost, because governments' cost of raising funds rise with the level of borrowing—high levels of borrowing at a particular time increase debt levels and limit the amount that can be borrowed later, thereby reducing government liquidity. These are further reasons why governments may be well-advised to entrust to private sponsorship those infrastructure investments that can be undertaken by private entrepreneurs.

### 4.3 Private Sector Participation in the Power Sector

The severe budgetary problems many governments in developing nations are faced with, has increasingly led them to turn to the private sector for infrastructure provision. This phenomenon is particularly evident in the electricity generating sectors of many countries.

According to the World Bank[8], the potential for competition in the power sector is greatest for thermal generation and distribution, because these activities can be unbundled from existing vertically- integrated power utilities and operated under concession. However, in virtually all countries, large-scale hydroelectric generation (because of unique environmental and risk features) is likely to remain publicly owned but can be operated on commercial principles—for example under management contracts. Small scale hydro-electric projects can be privately owned.

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[7] World Bank, World Development Report 1994: Infrastructure for Development, p.91

[8] World Bank, World Development Report 1994: Infrastructure for Development, p.116

Sector policies that take advantage of opportunities for competition in the generation of power can improve efficiency and lower costs. Concessions are an established means of increasing sectoral efficiency. In order to foster competition, the government must ensure that all private power producers have access to the national grid. The entire system should be coordinated by a network manager, to ensure system-wide efficiency.

Institutional change is needed to provide incentives for suppliers to seek economic tariffs, which are necessary to promote the self-financing of investment, conservation of energy, and more efficient use of existing capacity. Tariffs must also incorporate any environmental charges paid by power companies, in line with the principle that the polluter pays for any environmental costs it imposes on society. These necessary institutional reforms are discussed in more detail in Chapter 6.

### 4.3.1 *Modes of Private Sector Participation*

Various modes of private power generation have been adopted or proposed in nations around the globe. In the USA, electric power utilities are privately owned and are supervised by a state regulatory agency with wide-ranging powers. The large British utility—the Central Electricity Generating Board—has been privatized, and it now operates in the form of two power generating utilities. One company manages the national transmission grid, while the state still operates and owns the nuclear power generating stations. In the developing world too, fully private utilities exist in countries such as the Philippines, while more recently, faster growing economies such as Malaysia, have privatized their once state-owned electricity boards.

In some power generating systems that are fully privately owned, short term bidding is now being practiced, typically for the day ahead. In the UK, the National Grid Company prepares the load forecast for the day ahead and accepts offers from

Generating Companies and from other installations with large generating capacities to supply the predicted load. The generating projects themselves operate on a free-market basis, where, in most cases, the private developer meets the full cost of the project and assumes most of the risks.

It is often argued that such mechanisms are not yet appropriate for developing countries where the perceived risks are higher and therefore the expected returns are insufficient for project viability. More specifically, abrupt changes in government policies, excessive taxation, nationalization, and poor overall performance of some of these economies, add to the risks of private developers. Moreover, many developing countries still restrict direct foreign investment in the development of infrastructure and utilities. Hence, most attention is currently directed toward private-public partnership in the development of the infrastructure, which results in the sharing of risks, responsibility, and reward between the developer and the utility (or the state).

### 4.3.2 *Pros and Cons of Privatization*

Privatization is a policy decision which has wide repercussions on the political and social arena. The pros and cons of this process may be viewed differently by different entities. The advantages and disadvantages of privatization according to both the government, and the general public, are presented in this section.

Government Viewpoint[9]

*Advantages*

a) It can relieve the financial and administrative burden of the government in constructing and maintaining the much needed infrastructure.

b) The introduction of commercial discipline and possibly, competition, the economic efficiency and productivity of the projects are enhanced.

c) A vigorous cost benefit analysis and viability study will usually be carried out by the private sector to ensure profitability. Positive results add justification to the need for the facilities, whereas poor response from the private sector reflects an uncertain demand for the proposed facilities.

d) A shorter time for realizing the completion facilities is more probable as early income is desired by the private sector,

e) The public sector establishment size can be reduced, as the expertise of the private sector can be utilized

f) Economic growth can usually be expected to accelerate, because privatization stimulates private entreprenuership and investment,

g) Some of the risks of finance, construction, and operation are transferred to the private sector.

*Disadvantages*

a) There is trade-off in allowing the private sector to operate facilities and receive income since long-term revenue to the government is reduced or postponed in return for reduced risk taking.

b) The traditional state control of infrastructure is diluted, with a possibility of the government monopoly position being shifted to the private sector. An effective legal framework is, therefore, necessary to protect the public interest.

c) The quality of products produced or services rendered may be difficult to guarantee. This potential drawback can be mitigated by competent monitoring of

[9] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.188

the private sector's work. Usually, users of facilities have a certain power of influence over the quality standards, especially if cheaper alternatives exist.

d) The imposition of toll charges on previously free facilities may bring about public objection, which may be politically undesirable.

e) In order to attract investment, governments may have to provide incentives in the form of relaxation of taxation requirements and similar measures which may violate the consistency of established policy. Relaxation of foreign exchange regulation may undermine the country's balance-of-payment positions and credit rating.

f) Government may have to take over unsuccessful ventures before maturity of the franchise.

The General Public Perspective[10]

*Advantages*

Privatization may:

a) Relieve the otherwise probable imposition of tax burden for the development of needed infrastructure

b) Provide needed infrastructure in shorter time and relieve congestion, electricity blackout or overcrowding

c) Provide more efficient services

d) Create job opportunities which are not possible without private initiative in a sluggish economy.

[10] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.188

*Disadvantages*

On the other hand, privatization may:

a) Give rise to a possible monopoly situation
b) Create unemployment or loss of security benefits in the public sector if privatization involves the transfer of management and ownership to private operators
c) Create hardship to users, especially those in the lower income group.

The following table compares the government "design and build" system of infrastructure provision to the privatized BOT method.

Table 4.2[11]

## Comparison of "Design and Build" and the BOT method of Contract Procurement

| Factors | Design and Build (Government Owned) | BOT (by Private Sector) |
|---|---|---|
| Procurement | Contractor undertakes the design and construction of a project to meet performance requirements | Consortium undertakes to finance, design, build, and operate a project and return ownership to the government after a fixed concession period |
| Stability | Can be used in any time of project | Used where the completed project can generate revenue such as tolls for repayment of loans and profits thereafter |
| Contract | Design and build contract between government and contractor | Concession agreement made between government and concession company encompassing design and build obligations |
| Finance | Borne by government from public funds, bonds or loans | Borne by projects sponsors of the concession company from equity and loans |
| Contract Sum | Fixed-price lump-sum contract agreed between government and contractor before award of contract | Fixed-price lump-sum turnkey contract agreed between concession company and contractor |
| Payments | Contractor receives interim payments from government as the works proceed | Contractor (usually himself a project sponsor) receives interim payments from the concession company, which will not have revenue until the project is completed and in operation. |
| Risks (political, financial and technical) | Shared between contractor and government. Government can re-appoint by use of performance bond if the contractor is in default | Shared among project sponsors without recourse to government. Government can step in if they fail to complete the project as stipulated |

[11] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.192

Table 4.2 (contd.)

| Factors | Design and Build (Government Owned) | BOT (by Private Sector) |
|---|---|---|
| Time for completion | Agreed in contract, government safeguards by imposing liquidated and ascertained damages (LD) in case of delay | Completion guarantee by concession company<br>Government can take over the project if concession company fails to complete on time<br>Contractor liable for LD delay |
| Operation | By government or sale of operation franchise through private competition | By concession company or an operator who is usually a project sponsor |
| Defects | Borne by contractor within the defects liability period (DLP) | Borne by the turnkey contractor or the concession company |
| Maintenance beyond DLP | Borne by government or the franchised operator | Borne by the concession company within the concession period |

### *4.3.3 Variants of the Privatized Approach*

Although the BOT method of privatization is the most commonly considered system, other variations of this method have been proposed, and even implemented on occasion. The main methods such as BOOT, BOO, DBFO, BLT, LROT and BTO are presented below.

Build, Operate, and Transfer (BOT) Method

BOT is probably the most widely applied model, in which a private developer receives a license from the government to build a facility and to operate it for a specified period of time. At the end of this period, plant ownership reverts to the state. The duration of private ownership is intended to be sufficient to recover the capital, debt service and operating costs, in addition to allowing a reasonable profit for the private developer. The government and/or the utility guarantees the purchase of energy from the developer over the period of private ownership at an agreed price. In most cases, the risks are borne by the state.

The BOT scheme, and how it can be implemented in Sri Lanka will be discussed in more detail in the next chapter.

Build, Own, Operate, and Transfer (BOOT)

In a BOOT project, the government grants a private-sector organization a concession to build a facility, own it, operate it during the concession period, and then transfer it back to government. It differs from BOT in the ownership element, but the distinction is blurred in many cases because the two names are used almost interchangeably on the premise that transfer would eventually take place. A typical example of a BOOT contract is the Dartford Crossing, a toll bridge across River Thames in the UK[12].

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[12] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.191

Build, Own, Operate (BOO)

This type of project differs from BOT in that the promoting group designs, finances, constructs, and operates a project, with a plan to syndicate all or a portion of its equity after completion. Thus, the concession company retains ownership and operates the project indefinitely, continuing to derive revenue from it. A BOO scheme might provide more incentive for the project sponsor (hence the owners) to maintain the facilities during the concession period. Yet, except for the scenario that a lower user charge might result from the perpetual ownership, a BOO scheme is not generally welcome by host governments. The BOT arrangement offers more flexibility in that the host government can negotiate a new agreement for continued operation and maintenance with the original operator.

Design, Build, Finance, Operate (DBFO)

This acronym has been proposed for eight major road construction projects in the UK. One such project is a US$ 380 million contract for the A1-M1 link road and associated works in West Yorkshire[13]. The arrangement is BOT in essence, but the promoters' remuneration is paid through a shadow toll instead of direct tolling of motorists. This shadow toll is paid by the UK government based on traffic flow measured by sensing cables stretched across the road. This practice gives a much better guarantee of return to promoters as traffic would otherwise tend to switch to alternative untolled routes, given the existence of a great number of interconnecting roads in the UK. Although the shadow tolling would mean that the government would eventually have to foot the bill, the Treasury, in initiating this proposal, claimed that the scheme would result in a substantial transfer of risk to the private sector.

Build, Lease, Transfer (BLT)

In the BLT method, the private sector investors finance, design, build, and retain legal ownership of a facility for a stipulated period of time, but the host government

[13] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.194

leases it back for operation. This concept has been used successfully by the Standard Chartered Bank to procure its new headquarters building in Hong Kong at no cost (the bank's role was analogous to that of the government in most projects).

The Standard Chartered Bank owns the lease of a prime site in the Central Business District of Hong Kong, where its previous headquarters stood. In 1986, the bank awarded a 25-year sub-lease to Nishimatsu Property (Hong Kong), a subsidiary of the Japanese construction company Nishimatsu. In return, Nishimatsu financed the reconstruction of the Bank's new headquarters which was built on this property. Upon completion, Standard Chartered has the exclusive right to lease back 70% of the new floor areas at a fixed rental until expiry of the 25-year sub-lease, when the bank takes back the entire development at no cost. Nishimatsu covers its costs by renting out 30% of the commercial floor space on the open market[14].

Lease, Renovate, Operate, Transfer (LROT)

The LROT method can be illustrated with the following example[15]: A Japanese consortium consisting of Kobe Steel Ltd. and some trading companies leased a disused iron reduction plant from the Venezuelan government for eleven years, renovated and converted it to use a modern production process. The Japanese consortium financed the improvement cost, and also paid a fee per ton of product produced, which varied according to the selling price of the product. The government supplied the raw materials and assistance in obtaining necessary licenses. The Japanese consortium overcame foreign exchange restrictions by operating an offshore escrow account, into which foreign currencies generated by the exports of the products were paid. At the completion of the lease, the government will receive the renovated plant in good operating conditions free of charge.

[14] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.194
[15] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.195

Build, Transfer, Operate (BTO)

This model originated in France and is being used throughout Africa, Central and Eastern Europe. According to the BTO method, public facilities such as water and power are financed and built by the public sector, leaving maintenance and operation to the private sector. The Ivory Coast government constructed a power station, and signed a 15-year concessionary agreement with a private group, which is entrusted with the operation, maintenance and repair of all facilities related to power generation transmission and distribution throughout the Ivory Coast.

Similarly, several existing land tunnels in Hong Kong have recently been awarded by tender to the private sector following the government's decision to privatize their management and operations. Furthermore, the first chemical waste treatment center in Hong Kong has been developed under a BTO agreement, in which a private consortium obtained a 15-year franchise to operate the facility after its completion. The design and construction costs were initially borne by the consortium with deferred payment from the government within five years of completion. The center is designed to treat 100,000 tons of chemical waste per year, and the government intends to recover the costs (at least partially) from charging registered waste producers for the treatment[16].

### 4.3.4 *Risk Allocation*

At the heart of project financing is a contract that allocates risks associated with a project and defines the claims on rewards. Although it is often the cause of delay and heavy legal costs, efficient risk allocation has been central to making projects financable and has been critical to maintaining incentives to perform efficiently. Risks are divided not only between public and private entities, but also among the various private parties involved. Four kinds of risks can be distinguished—currency, commercial, policy-

[16] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.196

induced and country—although the distinctions among them are not always clear-cut[17]. I will give a brief explanation of these categories of risk here, and further discuss the particular risks associated with BOT projects in Chapter 5.

Currency Risk

Much recent, privately-financed infrastructure has drawn on foreign capital, and therefore faces the risk of local currency devaluation. International lenders rarely assume such risk, preferring instead to denominate their repayments in foreign currency terms. In the past, public enterprises or governments have borne the currency risk, but with the growing move to private finance, the risk of currency depreciation falls on the project sponsor, and ultimately on the consumers of the service. In many recent private projects, service prices have been linked to an international currency.

Commercial Risk

Two types of commercial risk may be distinguished: those relating to costs of production and those arising from uncertainties in demand for services. Substantial progress has been made in shifting cost-related risks onto private sponsors and other private parties. Typically, contracts include bonuses for early completion and penalties for late completion.

In telecommunications projects, the market risk is typically borne by the sponsor. In the electric power and water sectors, on the other hand, limitations on assumption of market risk arise because payments to cover costs are not assured. Also, governments need to be decisive in eliminating the prospect that investors will be bailed out if circumstances are unfavorable.

[17] World Bank, World Development Report 1994: Infrastructure for Development, p.98

Sector Policy-Induced Risk

In the power sector, project sponsors focus on the credibility and solvency of their buyer, typically a government utility that transmits and distributes power. The instrument that protects the power supplier is the "take-or-pay" contract, or power purchase agreement. Under such a contract, the buyer agrees to pay a specified amount regardless of whether or not the service is used. The government usually provides this assistance in the form of a contract compliance guarantee—a useful transitional measure while the long-term goal of sector reform is being addressed.

Country Risks

Even if governments do provide guarantees against sector policy or even commercial risks, these assurances may not always be acceptable to private international lenders, who may look instead for guarantees from creditor countries or from multilateral banks to insure against "country" risks. In any case, the role of the government does not disappear in such situations since counter-guarantees are typically required.

Multilateral Agency Participation in Risk Assessment and Mitigation

To attract international private capital to developing countries, several multilateral development banks, including the World Bank and ADB, have developed guarantee schemes. The World Bank's capital-market guarantees are used to facilitate the access of developing countries to international capital markets by lengthening the maturity of related borrowing. The proceeds from such loans can be used for infrastructure investments. The World Bank also issues guarantees for project financing—under the Extended Co-financing Facility (ECO)—to cover sovereign risks associated with infrastructure projects. This facility, designed to improve developing country access to international markets, has been used, for example, with the Hub River Project in Pakistan and a thermal power project in China.

### 4.3.5 *The BOT Method: the Most Common Privatization Scheme*

In spite of the existence of the various alternative privatization methods described above, the BOT method remains the most common scheme in use. Furthermore, when enacted, the other methods are usually merely variations on BOT. Given this propensity, I focus my discussion in the next chapter primarily on BOT, specifically exploring its relevance to the Sri Lankan power sector.

# CHAPTER 5

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## The BOT Approach to Privatization: its Application to Sri Lanka's Power Sector

The Build, Operate, Transfer scheme is probably the most widely applied model of privatization, especially in the newly-developing Asian nations. Such projects are entirely financed by private groups, giving governments with budgetary problems a way to construct much needed infrastructure. Furthermore, the eventual reversion of the assets to state control makes the process more politically feasible. Several developing countries have opted for this scheme. For example, the Philippines (National Power Corporation), has one BOT power generating project presently in operation, and two more under construction. Once completed, these projects will represent 15% of the total installed generating capacity of the Philippines grid[1].

Pakistan is another country which has experimented with this scheme, but with considerably less success. It has issued letters of intent for seven power projects, both thermal and hydroelectric, with capacities ranging from 6 MW to 1300 MW[2]. The proposed Hab River Project (oil-fired steam; 1300 MW) has been under negotiation since 1987. After the feasibility study, government approval was granted in 1989. Unfortunately, several partners in the private sector consortium involved have withdrawn from time to time, seriously delaying the implementation of the project. The experience of Pakistan emphasizes that BOT and other similar schemes are still mainly in the experimental stage, and still need considerable refining.

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[1] Siyambalapitiya, Tilak, Power Sector Development Issues: Private Power Generation: Part 2, p.19
[2] Siyambalapitiya, Tilak, Power Sector Development Issues: Private Power Generation: Part 2, p.19

The following table gives an overview of known BOT projects which are currently being planned, or already in operation:

Table 5.1[3]

| Country | Project | Status |
|---|---|---|
| Australia | Loy Yang 'B' Power Station<br>Collie Power Station (300 MW) | Under construction<br>Under construction |
| China | Shajiao 'B' Power Station<br>Shajiao 'C' Power Station<br>Huaneng Power Project | Operational (debt repaid March 1994)<br>Under construction<br>Unknown |
| Indonesia | Coal and nuclear power plants<br>Paiton Swata I/Coal | Proposed<br>Under construction |
| Laos | Champasac Hydro Dam | Under construction |
| Oman | Manah gas turbine power plant | Proposed |
| Pakistan | Hab river power plant<br>Fauji foundation power plant<br>Habibullah-Siemans Consortium Power Plant | Contracts signed<br>Letter of Intent<br>Letter of Intent |
| Philippines | Various Metro-Manila power plants<br>Several large coal fired power plants | Operating and under construction<br>Proposed |
| Poland | Walbrzyeh power plant | Under construction |
| Turkey | Akkuyu nuclear power plant<br>1000 MW coal fired power plant<br>Additional coal fired power plants<br>Hydro power plants | Abandoned<br>Contracts signed<br>Proposed<br>Under construction |
| Vietnam | Power plants (10 by year 2000) | In negotiation |

[3] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.27

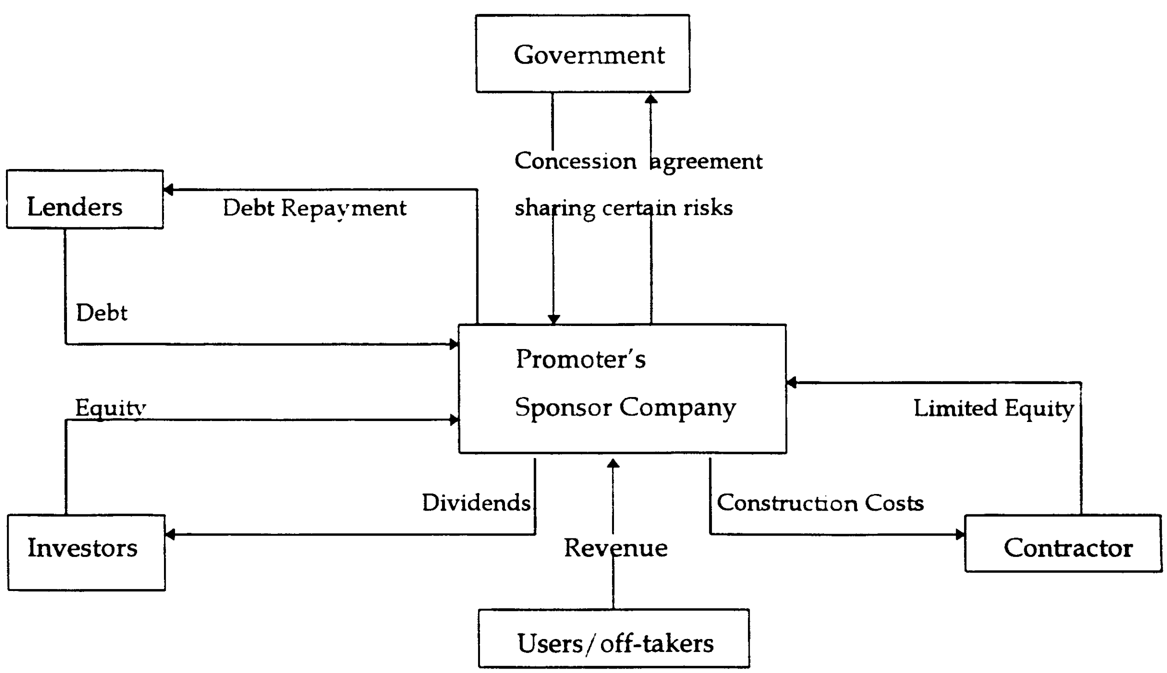
## 5.1 The BOT Concept

The Build Operate Transfer scheme has been described as follows:

> The technique that characterizes a Build Operate Transfer (BOT) arrangement, is the granting of a concession which empowers the right to operate and profit from the entity created by that concession. On expiration of the concession, the entity, bridge, canal, etc. transfers at no cost to those who granted the concession—for infrastructure projects this is most often the government. BOT concessions are typically 5 to 30 year terms[4].

The figure below shows the schematic layout of the relationship of the principal parties to a BOT.

Figure 5.1[5]




The above figure describes a scheme in which lenders look solely to the cash flows of a project to repay debt service, and where they have no recourse to other assets of the project participants if things go wrong; hence BOT's characterization as "non-recourse financing". Given its drawbacks, this approach is only used in cases where the project is clearly capable of supporting the debt[6].

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[4] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.6
[5] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.5
[6] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.5

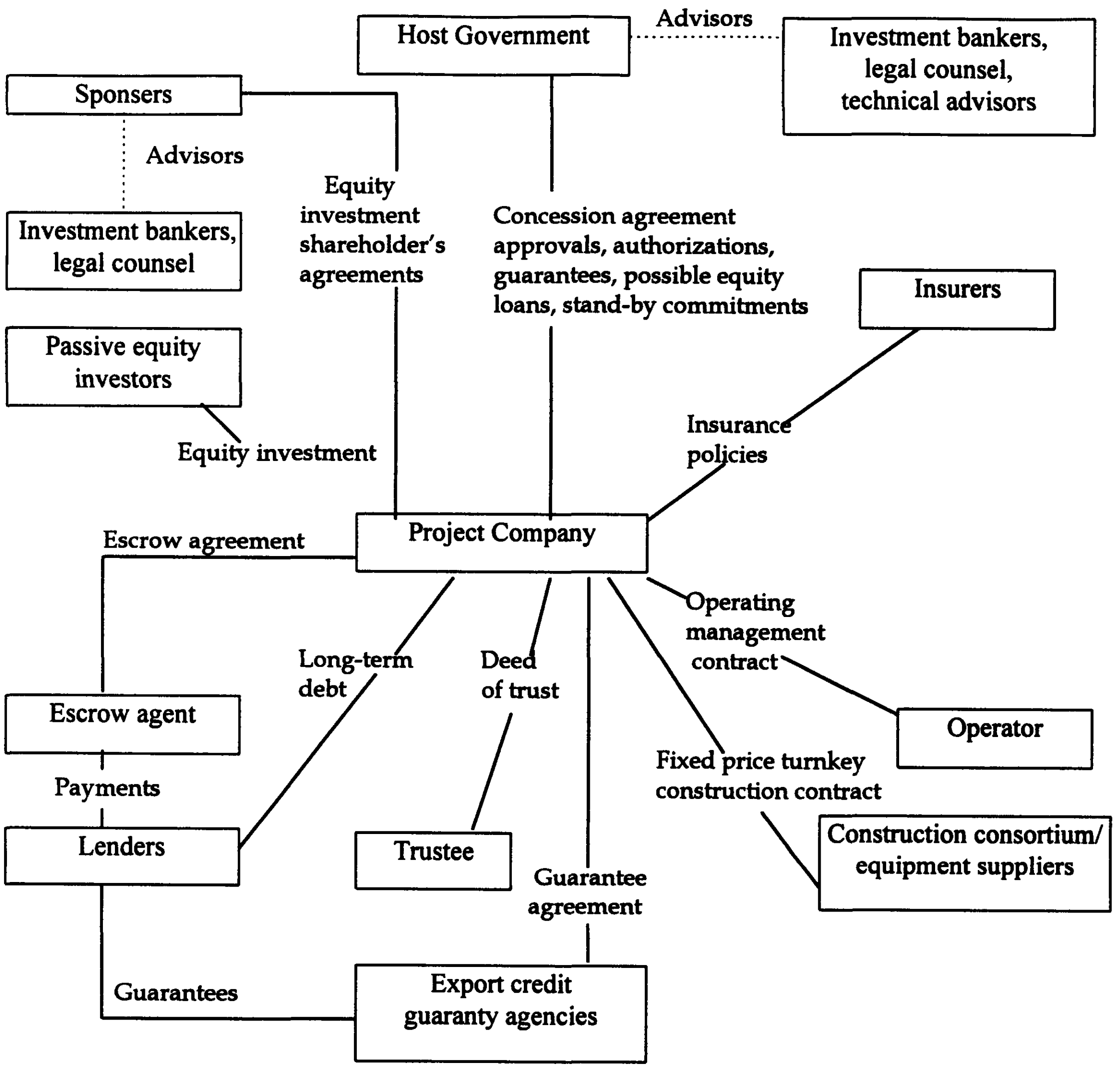
### 5.1.1 *Contractual Arrangements*

As the development and execution of any major project is often a difficult and uncertain process, the formalized risk relationships between government, lenders, investors, and contractors form the crux of all BOTs. These crucial ties should be addressed, arranged, documented, and regulated by the promoter/developer who must bring them into a workable formula that gives all involved parties the confidence that no single group is taking unreasonable risk or benefiting from unentitled reward[7].

The contractual arrangements in a typical BOT scheme is summarized in Figure 5.2.

[7] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.6

Figure 5.2[8]




[8] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.10

### 5.1.2 *Legal Framework*

BOT concepts depend largely upon the willingness of entrepreneurs to risk developing an enterprise, hoping it will meet the needs of enough customers to ensure its viability[9]. The willingness of entrepreneurs as well as those who lend them money to take these risks, depends very much on the legal environment in which they operate. If the law does not contain strong protection for sanctity of contracts backed by an impartial, judicial system, then entrepreneurship becomes restricted, and very high rates of return are demanded (because it is then assumed that a large percentage of such projects undertaken will be unprofitable).

The functions of a legal framework include[10]:

a) The definition of the overall concept and structure of the project (including project finance and taxation issues)
b) Establishment of enabling legislation and regulatory systems on environmental protection, planning, and user charges
c) Control of undue competition
d) Oversight of the negotiation of the respective rights and obligations and preparation of the associated documentation; allocating risks and identifying insurance requirements
e) Establishment of procedure for the resolution of disputes

## 5.2 Risks and Their Mitigation

In any BOT arrangement the contracted parties must acknowledge the conventional wisdom that risk should be assumed by the party within whose control the risk most lies. A major function of the BOT arrangement is, therefore, to recognize and provide a mechanism for the assignment and management of those risks[11].

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[9] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.17
[10] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.172
[11] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.6

The risks inherent in a BOT project have been grouped under three headings: financing risks, political risks and technical risks[12].

### 5.2.1 *Financing Risks*

Foreign exchange risks and interest rate fluctuations

Foreign exchange risk is especially relevant to developing countries, which have to import substantial amounts of equipment and materials using foreign currencies for settlement. Furthermore, repayment of foreign loans usually has to be in foreign currencies, even though the income arising from the use of the completed facilities or the sale of products (electricity, for example), are in local currency. As a result, if the local currency depreciates, the profitability of the project is drastically reduced (conversely, if it appreciates, the profitability is increased).

Project sponsors usually have to seek remittance and convertibility guarantees from the host government in order that the necessary transactions can be effected and project revenues can be remitted freely. Reluctance on the part of governments to give these guarantees inevitably discourages foreign investment in a country's infrastructure.

Fortunately, alternate solutions other than guarantees have evolved. For example, in the Shajiao 'B' coal-fired power station project in China, the Hong Kong developer is being paid fifty percent in the local currency, Renminbi (RMB), and fifty percent in foreign currency converted from RMB at predetermined exchange rates (thus partially mitigating currency risk). The developer uses the local currency to purchase coal from China at predetermined prices[13]. In other cases, an offshore "escrow account", effectively a trust fund established and funded by the proceeds generated by the venture, can be set up to which all project revenues and foreign loans are paid.

[12] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.143
[13] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.144

Market Risks

Changes in market price, demand, and sources of raw material supply will inevitably affect the construction and operation of projects. In industrial projects, lenders want to ensure the sale of the product so that there are sufficient revenues to repay their loans. Suppliers, therefore, are required to guarantee supply quantities and prices and even to secure the promise of alternative supply sources. Furthermore, the government, or more usually, the wholesale purchasers (such as utility companies), could guarantee their obligations by agreements to purchase the product on defined terms and prices.

Power stations offer common examples of these supply and "offtake" agreements. In its various BOT power projects in China and the Philippines, the Hopewell Group secures its fuel supply from the utility or joint venture partner associated with the projects during the "co-operation period"[14]. In the case of the Philippine projects, the local utility company supplies fuel at no charge, while in the Chinese projects, fuel is supplied at a fixed price or on terms which effectively protect the group from the extra costs incurred by any increases in the cost of fuel. On the offtake side, the local equity or cooperative joint venture partners of the project companies established by the Hopewell Group in China and the Philippines either pay a charge based on the available capacity of the plants, or purchase at a pre-agreed price a specified minimum amount of the electricity generated by the plants during the cooperation periods. Such contractual obligations have been guaranteed by state entities or governmental authorities for at least the period during which the project financing is available.

Income Risks

Income risk is often inherent in BOT transport projects, in which initial traffic forecasts may be overly optimistic, due to wrong assumptions, the availability of alternative routes, or an insufficient connecting road network. Income from direct

[14] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.144

tolls may then fall short of expectations, thereby jeopardizing the cash flow of the sponsor.

To mitigate this risk, the UK government encourages private financing by reimbursing project companies with "shadow tolls" based on recorded traffic flow rather than from tolls directly charged to road users. This practice gives a much better guarantee of return to funders because direct toll collection is complicated due to the great number of interconnecting roads which make switching to alternative routes easy for drivers.

Cost overrun risk

When construction costs exceed original estimates, either due to inflation or excessive design changes, it may be difficult to pay contractors from the original budget and additional sources of finance may have to be sought. These problems may also cause lenders to question the continued viability of the project. The Channel Tunnel project, with an estimated final project cost of US$ 15 billion, (more than double the initial estimate of US$ 7.4 billion), is an example[15]. These huge cost overruns caused the financing banks to threaten to take over the franchise before the project was eventually opened in May 1994.

Cost overrun risks can be mitigated by schemes which provide, for instance: as additional capital injected by project sponsors, standby credit facilities from original lenders, fixed price contracts from contractors, and sponsors' escrow funds for completion.

### 5.2.2 *Political Risks*

Political risk is often the most significant risk faced by foreign investors in the developing world, where there is the significant likelihood of dramatic overnight political change, which can jeopardize projects at a critical stage. Sovereign risks and instability risks are the two main types of risk in this category.

[15] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.149

Sovereign Risks

These risks are usually due to a change of government composition. One of the main reasons for the abandonment of the Channel Tunnel project in 1975 was the 1974 change of government in UK from Conservative to Labor, which left the project without any effective political sponsorship. Another example is a Thai rail and highway project awarded to Hopewell Holdings which was delayed by a military coup in Thailand in 1991[16].

A further sovereign risk involves the possible change of legislation. Governments may amend or repeal legislation because of purely domestic considerations, such as changes in economic policy, or as part of wider constitutional issues. Sponsors of BOT projects sometimes manage to obtain agreements from the host governments to restrict such changes but the value of such agreements are doubtful against a government which is determined to change the ground rules. Nevertheless, most governments are interested in having more than one infrastructure project supported by the private sector, and usually act in a manner which will not deter future investment.

A more subtle form of sovereign risk (especially relevant to developing countries), is the volatility of promises given under strong personal influence. An example is the uncertainty which faced the Bangkok rail and highway project when top officials in the ousted government were removed following the 1991 coup.

Instability Risk

Instability risk can range from labor unrest and embargo of construction equipment to outright expropriation. Construction companies could be forced into bankruptcy by a political decision to stop work. This risk can also arise when there is war or hostility between countries. Major political uprisings can likewise take away financiers' interest in otherwise lucrative projects, at least temporarily. For example,

[16] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.151

the Tiananmen Square incident in China in June 1989 caused the syndication of loans for the Guangzhou-Shenzhen-Zhuhai superhighway to be delayed until 1991[17]. Therefore, investors should address the possible instability risks associated with countries they plan to invest in.

Taing and Nevitt[18] suggest the following ways in which protection can be sought by investors in BOT projects in potentially unstable countries:

a) Obtain the government's agreement to allow the project sponsors to exploit the particular investment for a given period of time. However, if investors rely too much on this sort of agreement, they are betting heavily on the long-term stability and consistency of the policies of the host government.
b) Form a consortium of international investors and lenders so that expropriation of the project facility, will result in default of a number of international loans and jeopardize the country's credit rating to an unacceptable degree.
c) Take out a political risks insurance policy. Government agencies such as the Export Credits Guarantee Department (ECGD) in the UK or other multilateral development agencies such as the World Bank (through an affiliate called the Multilateral Investment Guarantee Agency – MIGA) offer various guarantee schemes. In the United States, agencies such as the Overseas Private Insurance Corporation (OPIC) provide coverage for investment abroad.
d) Negotiate for a financial undertaking by the host government. Lenders normally insist that host governments provide some coverage for outstanding debt and other financial obligations for uninsurable *force majeure* events. Both the Bangkok Second Stage Expressway and the Gazi power project in Turkey have concession agreements containing these protective features.

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[17] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.151
[18] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.151

### 5.2.3 *Technical Risks*

Risks in this category include construction difficulties, completion delays, and operation risks.

Construction Difficulties

Unforeseen soil conditions and breakdown in equipment are common occurrences on any construction site, especially in the case of large civil engineering projects. Usually, these will have repercussions on cost and time, but they are usually surmountable with today's technology.

For example, during the construction of the Eastern Harbor Crossing in Hong Kong, unexpected weakness in the harbor bed caused severe flooding and erosion of the tunnel's foundation. This resulted in some interim delay but engineers and contractors were able to overcome the problem and actually finished ahead of schedule. Construction contracts under BOT arrangement are usually of the Design and Build type, which do not provide redress for contractors against adverse geological conditions. Contractors usually either include a substantial risk allowance in the price or simply gamble and hope for the best when faced with the constraints of lump-sum fixed-price contracts.

Completion Delays

Projects can be delayed for many reasons, among which poor interface coordination and late design changes are the most common. The Channel Tunnel project for example, was allegedly delayed by the late changes in the signaling system specification and the shuttle design. There was a delay of an entire year out of the seven year construction contract. As BOT projects rely on the income of the completed facilities to service their debts, the accumulated interest from a delayed project can be substantial and can seriously damage the project's profitability. Accordingly, financiers of the Channel Tunnel were reluctant to commit further loans when considerable delay resulted in substantial cost increase.

Project sponsors should take positive steps to make sure that projects are completed on time. In particular they need to design and implement appropriate organization structures, especially those concerning project management. They can also commit contractors to lump sum contracts, using proven technology and agreed milestone schedules, which define contractually the timing and relationship of critical stages of the projects with payment incentives. Less positive measures include imposing of heavy liquidated damages based on expected loss. Contractors could also be required to provide completion guarantees and performance bonds. In the latter case the risk of cost increases due to late completion is borne by insurance companies or banks, who charge a premium for this service.

Operation Risks

During their operation, the revenue-generating capability of facilities may be hindered by equipment breakdown or other similar causes. As a countermeasure, local staff involved in operation and maintenance should be given adequate training in power system operation. Contractors should also be required to provide maintain and correct defects in the equipment they installed. Maintenance bonds will further provide a source of funds for remedial work. Other more positive steps include, the careful choice of an operator, and involvement of this operator in the design and commissioning phases.

### 5.3 Significant components of BOT Projects

The following table summarizes the various risks outlined above, and possible ways for their mitigation.

Table 5.2: Construction Phase[19]

| Risks | Solutions |
|---|---|
| Completion delays | • Experienced turnkey operator<br>• Penalties, liquidated damages, performance bonus<br>• Completion/performance guarantees<br>• Proven technology |
| Cost overruns | • Fixed-price/lump-sum contracts<br>• Standby credit<br>• Increased equity |
| Force majeure | • Government indemnities<br>• Insurance |
| Political risk | • Insurance<br>• Export credit agency cover |
| Infrastructure | • Government assurances |

Table 5.3: Operation Phase[20]

| Risks | Solutions |
|---|---|
| Revenue Stream | • Market study/traffic growth etc. |
| Performance/technical | • Proven technology<br>• Performance guarantees<br>Contractor's equity |
| Operation/maintenance | • Contractor/licenser involvement<br>• Experienced operator |
| Foreign exchange | • Flexible price formula<br>• Central bank assurances<br>• Swaps<br>• Escrow accounts |
| Other contingencies | • Government support<br>• Covenants |

[19] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.7
[20] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.7

## 5.4 Measures of Project Viability

Although there is no single criterion by which a banker or investor expects to judge the financial viability of a project, there are a considerable number of recognized measuring tools which can be used. The sponsoring group usually makes figures, generated from the financial model, which indicate the project's likely financial characteristics for both lenders and investors to review, verify, or amend.

Some of these important measures include the following:

Return of Investment (ROI)

The return on investment refers to the internal rate of return for the unleveraged projected cashflows to be generated by the project. The project is usually deemed feasible, and therefore fundable, if ROI is sufficiently high, ideally eight to ten points above the prime borrowing rate[21].

Return on Equity (ROE)

The ROE is the internal rate of return for the leveraged cash flows projected to be generated by a project. The project is usually considered to be attractive if ROE is at least ten points above the prime rate. In Sri Lanka, the prime lending rate (by commercial banks), is about 20% (Table 2.7). This will result in a required ROE of 30% – the figure which I used in the analysis, later in the chapter.

Net Present Value (after taxes) (NPV)

The NPV of a project is the difference between the present value of annual residual cashflows after debt amortization, interest, and income taxes, and the present value of equity investment at a specified discount rate. The project is only considered feasible if the NPV is positive and yields an acceptable return on

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[21] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.39

investment compared with other alternatives. I will discuss how to choose the "right" discount rate, at the end of this section.

Payback Period (PP)

The payback period refers to the amount of time required to recover initial investment. This may be measured as unleveraged returns against total cost (excluding construction, interest, and fees), or on dividends against equity disbursements. This measure is very much a function of the project's size but it is obviously desirable for the payback period to be as short as possible, particularly if country and sovereign risks are high.

Debt Service Coverage Ratio (DSCR)

The DSCR is usually expressed as a percentage ratio of the project's net cashflow from operation to its debt service due in any period as shown below[22]:

$$\frac{\text{revenue - operating costs - taxes - increase in working capital}}{\text{principal + interest}}$$

The project will usually be considered viable only if the minimum DSCR is in excess of 125% (or 1.25).

[22] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.39

Actual values of the above measures for some current projects

Published historical statistics on the above five measures are not commonly available because of commercial sensitivities. However, the World Bank's (Augenblick and Scott-Custer) 1990 paper, cited the ROE shown in Table 5.4:

Table 5.4[23]

| Project | Information Source | Projected ROE |
|---|---|---|
| Pakistani Power Projects | Presentation of Mohammed Akram Khan, Advisor, Ministry of Water and Power, Government of Pakistan, London BOT Conference, June 1989 | 18 |
| Gazi Power Plant, Turkey | Stevenson, The Turkish BOT power project experience. May 1989 | 16 |
| Labuan Water Supply Project Malaysia | Remarks of Mohamed Hanafiah Omar, London, BOT Conference, June 1989 | 18-20 |
| Bangkok Second Stage Expressway | BECL, Presentation to Investors, September 1988 | 3-21* |

(* These are the figures for the base case assumptions. The 3% return is for the first 10 years, it becomes 21% over the 31-year life of the concession.)

The Equity/Debt mix

The equity/debt mix of the project is highly case specific, and depends largely on the nature of the project and who is sponsoring it. Nevertheless, as my subsequent analysis will indicate, it is possible to increase ROE and DSCR values by optimizing equity disbursement.

Equity/debt values for some existing BOT projects are given in Table 5.5:

[23] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.40

Table 5.5[24]

| Developed Countries | Project | Equity/Debt |
|---|---|---|
| Australia | Sydney Harbor Crossing | 5:95 |
| UK | Channel Tunnel<br>Dartford Bridge Crossing<br>Second Severn Bridge<br>Midlands Expressway<br>Skye Bridge | 20:80<br>0:100<br>0:100<br>25:75*<br>0:100 |
| Hong Kong | Original Cross Harbor Tunnel<br>Eastern Harbor Crossing<br>Tate's Cairn Tunnel<br>Western Harbor Crossing | 0:100<br>25:75<br>28:75<br>30:70 |

| Developing Countries | Project | Equity/Debt |
|---|---|---|
| People's Republic of China | Shinjiao 'B' power plant<br>Guangzhou-Shenzhen-Zuhai Highway | 3:97<br>20:80* |
| Malaysia | North-South Highway | 10:90 |
| Thailand | 2nd Stage Expressway<br>Bangkok Elevated Transport System | 20:80<br>7:93 |

*Estimates

## Choosing the "Right" Discount Rate

The discount rate used in project valuation, is an extremely important value, because a choice of figure alone can drastically change the profitability of a project (this will be evident in my subsequent analysis). Walker and Smith say the following about choosing the "right" discount rate.

> Life cycle cost predictions are frequently made net of inflation, with the discount rate taking into account of both future inflation and interest rates. Choice of the correct discount rate is, therefore, of fundamental importance. Long-term interest rates are very difficult to predict with any degree of accuracy, but there is generally considered to be a relationship, usually roughly stable, between the inflation rate and market investment rates from which a real rate of interest (i.e. a positive rate of return net of inflation) can be calculated. In the absence of any other information this is the value usually used as the

In the following section I will give a short overview of the main characteristics of each of the three proposed plants.

[24] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.41

discount rate in DCF calculations. It is important to keep in mind, however, that the relationship between interest and inflation rates may vary over time[25].

The "real" discount rate (d) which takes into account of both inflation and the prevailing interest rate (usually the bank base rate), can be calculated from the following formula:

where: $d= [(1+b)/(1+i)-1] \times 100$

$b=$ bank base rate

$i=$ prevailing inflation rate

The proof for the derivation of the formula may be found in Kelly and Male[26].

Although the above formula may give a rough measure of the discount rate, the value suitable for calculating cash flows is a matter of individual professional judgment and may vary from project to project depending upon the way the venture is to be financed. In the case of projects financed largely by debt, the appropriate rate is usually the actual cost of borrowing the money, net of inflation. However, different criteria may apply in the case of equity finance.

[25] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.141

[26] Smith and Walker, Privatized Infrastructure: the Build Operate and Transfer approach, p.141

40 MW Diesel Generating Plant

This plant will be developed and operated by a private organization, over a period of 10 years for the first case, and 15 years for the second case after which the assets will be turned over to the government. The intricate details of investment, power purchase and asset transfer, which usually occur in such a situation, have been left out in the analysis for simplicity.

The specifics of the project are summarized in the table below:

Table 5.6[27]

| | |
|---|---|
| **Net Present Value of Total Disbursement (Equity, Loan and Interest)**<br>(constant 1995 prices) | Rs. 3 billion (10 year BOT)<br>Rs. 2.5 billion (15 year BOT) |
| **Financing Basis**<br>Developer's Equity | <br>30% |
| **Loan Basis**<br>Annual Interest Rate<br>Repayment period (equal annual payments) | <br>15%<br>10 and 15 years (for the two cases) |
| **Tax Basis** | Investments are tax and duty free |
| **Fuel Details**<br>Cost of residual oil excluding tax and duty<br>Heat content of fuel<br>Thermal efficiency<br>Specific fuel consumption<br>Specific fuel cost | <br>3.83 Rs/l<br>9952.2 kCal/l<br>39.6%<br>0.218 l/kWh<br>0.84 Rs/kWh |
| **Project details**<br>• The plant will be constructed on the BOT concept<br>• The plant can be constructed at the same cost as that estimated by the CEB<br>• It will be transferred to the government ownership after the 10th and 15th years respectively, for first and second cases<br>• Energy output is based on system merit order dispatch (no purchase guarantee) | |

70 MW Hydroelectric Plant

In this case, I will consider the development of the proposed Kukule hydroelectric plant according to the BOT method. The project, which is located on the Kalu Ganga (river), has 70 MW of installed capacity, and an annual energy capability of 305 GWh/year. It is estimated to cost Rs. 6.7 billion (US$ 135 million) in constant 1993 prices, and will be commissioned in 1999.

The specifics of the project are summarized in the table below:

[27] Siyambalapitiya, Tilak. Power Sector Development Issues: Private Power Generation: Part 2, p.39

## 5.5 The Possible Use of the BOT Concept in Sri Lanka

According to the CEB generation expansion plan (presented in Table 3.6), many new power generating plants must be constructed within the next ten years in order to meet the rapidly growing (10% per annum) demand for electricity in the country. Unfortunately, the government is facing severe budgetary shortfalls, partly because of its increased defense spending due to the civil war in the north and east, and has not been able to finance this additional generating capacity. As a result, the CEB has been forced to introduce widespread power cuts which in turn have adversely affected the country's economic growth.

In response to this problem, the government has been actively exploring the possibility of financing the required power stations by using BOT schemes, but so far, has not been successful in its efforts. It is important to understand the reasons for the government's lack of success, and determine the conditions that will attract private investment. The government will then be able to determine whether BOT schemes can be used to provide electricity at reasonable prices to consumers.

In this section, I will examine the feasibility of adding three different power plants, built under the BOT concept, to the national grid, and try to determine under which conditions they will be feasible for the private developer. The cases I will examine are:

- 40 MW diesel plant (10 year BOT)
- 40 MW diesel plant (15 year BOT)
- 70 MW Kukule hydroelectric plant (15 year BOT)
- 300 MW coal plant (15 year BOT)

The above plants are among those to be constructed according to the CEB's 1993 generation expansion plan. The diesel plant, the Kukule hydro plant, and the 300 MW coal plant were supposed to be commissioned in 1998, 1999, and 2001 respectively. However, since the whole schedule has been delayed, it is extremely likely that each plant will be constructed three years behind schedule. This change is reflected in my subsequent analysis.

300 MW Coal Plant

The proposed development of a coal-fired power station is the largest single investment planned in Sri Lanka's power sector. This project is estimated to cost Rs. 23.2 billion (US$ 464 million) in constant 1993 prices. The initial 150 MW will be completed in 2001, and the second 150 MW unit will follow in 2002. Supplies of low sulfur coal need to be secured from either Australia or South Africa at the projected prices of US$ 50/MT.

The specifics of the project are summarized in the table below:

Table 5.8[29]

| | |
|---|---|
| **Net Present Value of Total Disbursement (Equity, Loan and Interest)**<br>(constant 1995 prices) | Rs. 25 billion |
| **Financing Basis**<br>Developer's Equity | 30% |
| **Loan Basis**<br>Annual Interest Rate<br>Repayment period (equal annual payments) | <br>15%<br>15 years |
| **Tax Basis** | The investments are tax and duty free |
| **Fuel Details**<br>Cost of coal excluding tax and duty<br>Heat content of fuel<br>Thermal efficiency<br>Specific fuel consumption<br>Specific fuel cost | <br>2208 Rs/MT<br>6660 kCal/kg<br>33.6%<br>0.384 kg/kWh<br>0.85 Rs/kWh |
| **Project details**<br>• The plant will be constructed on the BOT concept<br>• The plant can be constructed at the same cost as that estimated by the CEB<br>• It will be transferred to the government ownership after the 15th year<br>• Energy output is based on system merit order dispatch (no purchase guarantee) | |

[29] Siyambalapitiya, Tilak, Power Sector Development Issues: Private Power Generation: Part 2, p.42

Table 5.7[28]

| | |
|---|---|
| **Net Present Value of Total Disbursement (Equity, Loan and Interest)** (constant 1995 prices) | Rs. 7.5 billion |
| **Financing Basis**<br>Developer's Equity | 30% |
| **Loan Basis**<br>Annual Interest Rate<br>Repayment period (equal annual payments) | 15%<br>15 years |
| **Tax Basis** | The investments are tax and duty free |
| **Project details**<br>• The plant will be constructed on the BOT concept<br>• The plant can be constructed at the same cost as that estimated by the CEB<br>• It will be transferred to the government ownership after the 15th year | |

[28] Siyambalapitiya, Tilak, Power Sector Development Issues: Private Power Generation: Part 2, p.41

## 5.6 Assumptions

The following assumptions are implicit in the model I used for my analysis:

a) The plants will be built at the same cost as that estimated by the CEB.

b) Calculations are done in constant 1993 terms and hence exclude inflation and exchange rate increases.

c) There will be 30% equity participation by the developer.

d) The principal with accumulated interest during construction will be paid by the developer in equal annual installments, beginning in the first year of plant operation. Annual interest payments will be on the remaining balance.

e) The projects will be transferred to public (state utility) ownership at the end of the specified period with no compensation paid (more details about this transfer period are found in the notes at the end of each table).

f) Interest on debt is taken as 15% per year. This is also the opportunity cost of capital which is used for the discounted cash flow calculations.

g) The utility's purchase is on a one-part tariff based only on energy, fixed at 2.89 Rs./kWh (this value was used because, according to CEB forecasts, this is the long term (20-year) average incremental economic cost of generation for the Sri Lanka Power System)[30].

h) Except for the second case involving the diesel plant, no purchase guarantees will be given to the operator, who will the operate the plant to meet system merit order dispatch.

i) All investments, imports and profits are free of customs duty and income tax.

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[30] Ceylon Electricity Board: Generation Planning Branch, Report on Long Term Generation Expansion Planning Studies 1995-2009 (Colombo, Sri Lanka: October 1994), p.8-3

## 5.7 Project Performance Indicators

Of the various performance indicators I described in the previous section, I chose two, return on equity (ROE), and debt service coverage ratio (DSCR), to determine the feasibility of the particular project. For the purpose of my analysis, these two measures are defined as follows:

Return on Equity (ROE):

Internal rate of return calculated on net cash-flows before debt service

Debt Services Coverage Ratio (DSCR):

(Present Value of cash-flows before debt service) / ( Total accumulated debt before project commissioning)

I have assumed that in order to attract financiers, the ROE must be over 30% and the DSCR must be over 1.5. The ROE value was chosen because of the standard practice of adding 10 percentage points to the prime borrowing rate (20% for Sri Lanka in 1995), and the DSCR value is that which is commonly used for similar projects.

## 5.8 Variables

The discount rate (initially 15%), the purchase price (initially 2.89 Rs./kWh) and the equity participation rate (initially 30%), are the values I varied in my analysis. I examined the resulting ROE and DSCR values obtained by changing the above variables in order to determine the conditions under which the various projects being considered will become feasible.

## 5.9 Models Used

I used the following cash flow models (on a Microsoft Excel spreadsheet) to calculate the ROE and DCSR values of the projects under various conditions. The feasible scenarios were those which produced ROE values of over 30% and DCSR values of over 1.5.

The results shown in Tables 5.9 to 5.12 are those obtained for the base case for each project (discount rate=15%, equity participation level=30%, and selling price= 2.89 Rs./kWh).

**Table 5.9: Cash Flow Analysis of a 40MW Diesel Plant Developed on a BOT Basis for Commissioning in 1997 (Power Sector Issues II, 39): Rs/kWh=2.89**

| | Year | Investment | Equity Disb. | Capital | Interest | Total | Maintenance | Fuel Cost | Total Cost | Output (GWh) | Revenue | NI w/o DS | Net Income |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction | 1996 | 221 | 66 | 155 | 23 | 178 | 0 | 0 | 0 | 0 | 0 | 0 | -66 |
| Construction | 1997 | 1330 | 399 | 931 | 163 | 1094 | 0 | 0 | 0 | 0 | 0 | 0 | -399 |
| Construction | 1998 | 715 | 215 | 501 | 238 | 738 | 0 | 0 | 0 | 0 | 0 | 0 | -215 |
| | 1999 | 0 | 0 | -201 | -271 | -472 | -38 | -205 | -715 | 245 | 708 | 465 | -7 |
| | 2000 | 0 | 0 | -201 | -241 | -442 | -41 | -216 | -699 | 258 | 746 | 489 | 46 |
| | 2001 | 0 | 0 | -201 | -211 | -412 | -41 | -219 | -672 | 262 | 757 | 497 | 85 |
| | 2002 | 0 | 0 | -201 | -181 | -382 | -39 | -210 | -631 | 251 | 725 | 476 | 94 |
| | 2003 | 0 | 0 | -201 | -151 | -352 | -35 | -188 | -575 | 225 | 650 | 427 | 75 |
| | 2004 | 0 | 0 | -201 | -121 | -322 | -41 | -218 | -581 | 260 | 751 | 492 | 171 |
| | 2005 | 0 | 0 | -201 | -90 | -291 | -39 | -206 | -536 | 246 | 711 | 466 | 174 |
| | 2006 | 0 | 0 | -201 | -60 | -261 | -19 | -100 | -380 | 119 | 344 | 225 | -36 |
| | 2007 | 0 | 0 | -201 | -30 | -231 | -33 | -175 | -439 | 209 | 604 | 396 | 165 |
| | 2008 | 0 | 0 | -201 | 0 | -201 | -39 | -207 | -447 | 248 | 717 | 471 | 270 |

| | |
|---|---|
| Interest | 15% |
| Debt before operation | 2010 |
| Annual principal payment | 201 |
| Payment for 1kWh (Rs.) | 2.89 |
| NPV of Total Disb. | 3,093.01 |

**Return on Equity** 6%

(Internal rate of return calculated on net cash-flows to the developer after allowing for equity)

| | |
|---|---|
| PV before debt service | 2276 |
| Total debt at project commissioning | 2010 |
| **Debt Services Coverage Ratio** | 1.13 |

| | | |
|---|---|---|
| Financing Basis | Developer's equity | 30% |
| Loan Basis | Annual Interest rate | 15% |
| | Repayment Period (years) | 10 |
| | Equal annual payments | |
| Tax Basis | The investments are tax and duty free | |
| Fuel details | Cost of residual oil | 3.83 Rs/l |
| | Heat content of fuel | 9952.2 kCal/l |
| | Thermal efficiency | 39.60% |
| | Specific fuel consumption | 0.218l/kWh |
| | Specific fuel cost | 0.84 Rs/kWh |

Project Details

The plant will be constructed on BOT concept
The plant can be constructed at the same cost as that estimated by CEB
It will be transferred to the government ownership after the tenth year
Energy output is based on system merit order dispatch (no purchase guarantees)

**Table 5.10: Cash Flow Analysis of a 40MW Diesel Plant Developed on a BOT Basis for Commissioning in 1997 (Power Sector Issues II, 40): Rs/kWh=2.89**

| | Year | Investment | Equity Disb. | Capital | Interest | Total | Maintenance | Fuel Cost | Total Cost | Output (GWh) | Revenue | NI w/o DS | Net Income |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction | 1996 | 221 | 44 | 177 | 27 | 203 | 0 | 0 | 0 | 0 | 0 | 0 | -44 |
| Construction | 1997 | 1330 | 266 | 1064 | 186 | 1250 | 0 | 0 | 0 | 0 | 0 | 0 | -266 |
| Construction | 1998 | 715 | 143 | 572 | 272 | 844 | 0 | 0 | 0 | 0 | 0 | 0 | -143 |
| | 1999 | 0 | 0 | -153 | -322 | -475 | -38 | -205 | -718 | 245 | 708 | 465 | -10 |
| | 2000 | 0 | 0 | -153 | -299 | -452 | -40 | -216 | -708 | 258 | 746 | 490 | 38 |
| | 2001 | 0 | 0 | -153 | -276 | -429 | -41 | -219 | -689 | 262 | 757 | 497 | 68 |
| | 2002 | 0 | 0 | -153 | -253 | -406 | -39 | -210 | -655 | 251 | 725 | 476 | 71 |
| | 2003 | 0 | 0 | -153 | -230 | -383 | -35 | -188 | -606 | 225 | 650 | 427 | 44 |
| | 2004 | 0 | 0 | -153 | -207 | -360 | -41 | -218 | -619 | 260 | 751 | 492 | 132 |
| | 2005 | 0 | 0 | -153 | -184 | -337 | -39 | -206 | -582 | 246 | 711 | 466 | 129 |
| | 2006 | 0 | 0 | -153 | -161 | -314 | -19 | -100 | -433 | 119 | 344 | 225 | -89 |
| | 2007 | 0 | 0 | -153 | -138 | -291 | -33 | -175 | -499 | 209 | 604 | 396 | 105 |
| | 2008 | 0 | 0 | -153 | -115 | -268 | -39 | -207 | -514 | 248 | 717 | 471 | 203 |
| | 2009 | 0 | 0 | -153 | -92 | -245 | -25 | -131 | -401 | 157 | 454 | 298 | 53 |
| | 2010 | 0 | 0 | -153 | -69 | -222 | -37 | -199 | -458 | 238 | 688 | 452 | 230 |
| | 2011 | 0 | 0 | -153 | -46 | -199 | -37 | -197 | -433 | 235 | 679 | 445 | 246 |
| | 2012 | 0 | 0 | -153 | -23 | -176 | -38 | -202 | -416 | 241 | 696 | 456 | 280 |
| | 2013 | 0 | 0 | -153 | 0 | -153 | -29 | -154 | -336 | 184 | 532 | 349 | 196 |

| | |
|---|---|
| Interest | 15% |
| Debt before operation | 2297 |
| Annual principal payment | 153 |
| Payment for 1kWh (Rs.) | 2.89 |
| NPV of Total Disb. | 2,449.32 |

**Return on Equity** 13%

(Internal rate of return calculated on net cash-flows to the developer after allowing for equity)

| | |
|---|---|
| PV before debt service | 2605 |
| Total debt at project commissioning | 2297 |
| **Debt Services Coverage Ratio** | 1.13 |

| | | |
|---|---|---|
| Financing Basis | Developer's equity | 20% |
| Loan Basis | Annual Interest rate | 15% |
| | Repayment Period (years) | 15 |
| | Equal annual payments | |
| Tax Basis | The investments are tax and duty free | |
| Fuel details | Cost of residual oil | 3.83 Rs/l |
| | Heat content of fuel | 9952.2 kCal/l |
| | Thermal efficiency | 39.60% |
| | Specific fuel consumption | 0.218l/kWh |
| | Specific fuel cost | 0.84 Rs/kWh |

Project Details

The plant will be constructed on BOT concept
The plant can be constructed at the same cost as that estimated by CEB
It will be transferred to the government ownership after the fifteenth year
Energy output is based on system merit order dispatch (no purchase guarantees)

**Table 5.11: Cash Flow Analysis of a 70MW Kukule Hydroelectric Plant if Developed on a BOT Basis for Commissioning in 1999 (Power Sector Issues II, 41): Rs/kWh=2.89**

| | Year | Investment | Equity Disb | Capital | Interest | Total | Maintenance | Fuel Cost | Total Cost | Output (GWh) | Revenue | NI w/o DS | Net Income |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction | 1996 | 106 | 32 | 74 | 11 | 85 | 0 | 0 | 0 | 0 | 0 | 0 | -32 |
| Construction | 1997 | 523 | 157 | 366 | 66 | 432 | 0 | 0 | 0 | 0 | 0 | 0 | -157 |
| Construction | 1998 | 1915 | 575 | 1341 | 267 | 1608 | 0 | 0 | 0 | 0 | 0 | 0 | -575 |
| Construction | 1999 | 2909 | 873 | 2036 | 573 | 2609 | 0 | 0 | 0 | 0 | 0 | 0 | -873 |
| Construction | 2000 | 1027 | 308 | 719 | 680 | 1399 | 0 | 0 | 0 | 0 | 0 | 0 | -308 |
| | 2001 | 0 | 0 | -409 | -859 | -1268 | -11 | 0 | -1279 | 305 | 881 | 870 | -397 |
| | 2002 | 0 | 0 | -409 | -797 | -1206 | -11 | 0 | -1217 | 305 | 881 | 870 | -336 |
| | 2003 | 0 | 0 | -409 | -736 | -1145 | -11 | 0 | -1156 | 305 | 881 | 870 | -274 |
| | 2004 | 0 | 0 | -409 | -675 | -1084 | -11 | 0 | -1095 | 305 | 881 | 870 | -213 |
| | 2005 | 0 | 0 | -409 | -613 | -1022 | -11 | 0 | -1033 | 305 | 881 | 870 | -152 |
| | 2006 | 0 | 0 | -409 | -552 | -961 | -11 | 0 | -972 | 305 | 881 | 870 | -90 |
| | 2007 | 0 | 0 | -409 | -491 | -900 | -11 | 0 | -911 | 305 | 881 | 870 | -29 |
| | 2008 | 0 | 0 | -409 | -429 | -838 | -11 | 0 | -849 | 305 | 881 | 870 | 32 |
| | 2009 | 0 | 0 | -409 | -368 | -777 | -11 | 0 | -788 | 305 | 881 | 870 | 94 |
| | 2010 | 0 | 0 | -409 | -307 | -716 | -11 | 0 | -727 | 305 | 881 | 870 | 155 |
| | 2011 | 0 | 0 | -409 | -245 | -654 | -11 | 0 | -665 | 305 | 881 | 870 | 216 |
| | 2012 | 0 | 0 | -409 | -184 | -593 | -11 | 0 | -604 | 305 | 881 | 870 | 278 |
| | 2013 | 0 | 0 | -409 | -123 | -532 | -11 | 0 | -543 | 305 | 881 | 870 | 339 |
| | 2014 | 0 | 0 | -409 | -61 | -470 | -11 | 0 | -481 | 305 | 881 | 870 | 400 |
| | 2015 | 0 | 0 | -409 | 0 | -409 | -11 | 0 | -420 | 305 | 881 | 870 | 462 |

| | |
|---|---|
| Interest | 15% |
| Debt before operation | 6133 |
| Annual principal payment | 409 |
| Payment for 1kWh (Rs.) | 2.89 |
| NPV of Total Disb. | 7,493.79 |

**Return on Equity** -4%

(Internal rate of return calculated on net cash-flows to the developer, after allowing for equity)

| | |
|---|---|
| PV before debt service | 5090 |
| Total debt at project commissioning | 6133 |
| **Debt Services Coverage Ratio** | 0.83 |

| | | |
|---|---|---|
| Financing Basis | Developer's equity | 30% |
| Loan Basis | Annual Interest rate | 15% |
| | Repayment Period (years) | 15 |
| | Equal annual payments | |
| Tax Basis | The investments are tax and duty free | |
| Fuel details | Cost of residual oil | 3.83 Rs/l |
| | Heat content of fuel | 9952.2 kCal/l |
| | Thermal efficiency | 39.60% |
| | Specific fuel consumption | 0.218l/kWh |
| | Specific fuel cost | 0.84 Rs/kWh |

Project Details

The plant will be constructed on BOT concept
The plant can be constructed at the same cost as that estimated by CEB
It will be transferred to the government ownership after the fifteenth year
Energy output is based on system merit order dispatch (no purchase guarantees)

**Table 5.12: Cash Flow Analysis of a 300MW Coal Power Station if Developed on a BOT Basis for Commissioning in 2001 (Power Sector Issues II, 42): Rs/kWh=2.89**

| | Year | Investment | Equity Disb | Capital | Interest | Total | Maintenance | Fuel Cost | Total Cost | Output (GWh) | Revenue | NI w/o DS | Net Income |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Construction | 1996 | 350 | 105 | 245 | 37 | 282 | 0 | 0 | 0 | 0 | 0 | 0 | -105 |
| Construction | 1997 | 1138 | 341 | 797 | 156 | 953 | 0 | 0 | 0 | 0 | 0 | 0 | -341 |
| Construction | 1998 | 3312 | 994 | 2318 | 504 | 2822 | 0 | 0 | 0 | 0 | 0 | 0 | -994 |
| Construction | 1999 | 6782 | 2035 | 4747 | 1216 | 5964 | 0 | 0 | 0 | 0 | 0 | 0 | -2035 |
| Construction | 2000 | 7142 | 2143 | 4999 | 1966 | 6965 | 0 | 0 | 0 | 0 | 0 | 0 | -2143 |
| Construction | 2001 | 3662 | 1099 | 2563 | 2351 | 4914 | 0 | 0 | 0 | 0 | 0 | 0 | -1099 |
| Construction | 2002 | 802 | 241 | 561 | 2435 | 2996 | -17 | -779 | -3792 | 918 | 2653 | 1857 | -1139 |
| | 2003 | 0 | 0 | -1660 | -3485 | -5145 | -33 | -1555 | -6733 | 1833 | 5297 | 3709 | -1436 |
| | 2004 | 0 | 0 | -1660 | -3236 | -4896 | -33 | -1575 | -6504 | 1856 | 5364 | 3756 | -1140 |
| | 2005 | 0 | 0 | -1660 | -2988 | -4647 | -33 | -1461 | -6141 | 1722 | 4977 | 3483 | -1165 |
| | 2006 | 0 | 0 | -1660 | -2739 | -4398 | -33 | -1455 | -5886 | 1715 | 4956 | 3468 | -930 |
| | 2007 | 0 | 0 | -1660 | -2490 | -4149 | -33 | -1572 | -5754 | 1852 | 5352 | 3747 | -402 |
| | 2008 | 0 | 0 | -1660 | -2241 | -3900 | -33 | -1482 | -5415 | 1747 | 5049 | 3534 | -367 |
| | 2009 | 0 | 0 | -1660 | -1992 | -3651 | -33 | -1559 | -5243 | 1837 | 5309 | 3717 | 66 |
| | 2010 | 0 | 0 | -1660 | -1743 | -3402 | -33 | -1559 | -4994 | 1837 | 5309 | 3717 | 314 |
| | 2011 | 0 | 0 | -1660 | -1494 | -3153 | -33 | -1562 | -4748 | 1841 | 5320 | 3725 | 572 |
| | 2012 | 0 | 0 | -1660 | -1245 | -2905 | -33 | -1521 | -4459 | 1793 | 5182 | 3628 | 723 |
| | 2013 | 0 | 0 | -1660 | -996 | -2656 | -33 | -1439 | -4128 | 1696 | 4901 | 3429 | 774 |
| | 2014 | 0 | 0 | -1660 | -747 | -2407 | -33 | -1523 | -3963 | 1795 | 5188 | 3632 | 1225 |
| | 2015 | 0 | 0 | -1660 | -498 | -2158 | -33 | -1523 | -3714 | 1795 | 5188 | 3632 | 1474 |
| | 2016 | 0 | 0 | -1660 | -249 | -1909 | -33 | -1523 | -3465 | 1795 | 5188 | 3632 | 1723 |
| | 2017 | 0 | 0 | -1660 | 0 | -1660 | -33 | -1523 | -3216 | 1795 | 5188 | 3632 | 1972 |

| | |
|---|---|
| Interest | 15% |
| Debt before operation | 24,896 |
| Annual principal payment | 1,660 |
| Payment for 1kWh (Rs.) | 2.89 |
| NPV of Total Disb. | 25,020.32 |

**Return on Equity** -3%
(Internal rate of return calculated on net cash-flows to the developer, after allowing for equity)

| | |
|---|---|
| PV before debt service | 20104 |
| Total debt at project commissioning | 24896 |
| Debt Services Coverage Ratio | 0.81 |

| | | |
|---|---|---|
| Financing Basis | Developer's equity | 30% |
| Loan Basis | Annual Interest rate | 15% |
| | Repayment Period (years) | 15 |
| | Equal annual payments | |
| Tax Basis | The investments are tax and duty free | |
| Fuel details | Cost of residual oil | 3.83 Rs/l |
| | Heat content of fuel | 9952.2 kCal/l |
| | Thermal efficiency | 39.60% |
| | Specific fuel consumption | 0.218l/kWh |
| | Specific fuel cost | 0.84 Rs/kWh |

**Project Details**

The plant will be constructed on BOT concept
The plant can be constructed at the same cost as that estimated by CEB
It will be transferred to the government ownership after the fifteenth year
Energy output is based on system merit order dispatch (no purchase guarantees)

## 5.10 Structure of Analysis

I performed my analysis by varying certain values, and keeping others constant in the following manner:

*(A) Changing One Variable at a Time*

I. Varying the Selling Price

A. Holding Discount Rate=15%, and Equity Participation=30% constant

II. Varying the Discount Rate

A. Holding Selling Price=2.89 Rs/kWh, and Equity Participation=30% constant

B. Holding Selling Price=3.50 Rs/kWh, and Equity Participation=30% constant

III. Varying the Equity Participation Level

A. Holding Selling Price=2.89 Rs/kWh, and Discount Rate=15% constant

B. Holding Selling Price=3.50 Rs/kWh, and Discount Rate=15% constant

*(B) Changing Two Variables at a Time*

I. Discount Rate and Selling Price

A. Holding Equity Participation=30% constant

II. Selling Price and Equity Participation

A. Holding Discount Rate=30% constant

III. Discount Rate and Equity Participation

A. Holding Selling Price=2.89 Rs./kWh constant

B. Holding Selling Price=3.00 Rs./kWh constant

C. Holding Selling Price=3.50 Rs./kWh constant

### *5.10.1 Changing One Variable at a Time*

(I) Varying Selling Price

According to my analysis, the selling price (the price at which the CEB purchases power from the private developer), is the most crucial variable determining the viability of the project. Keeping equity participation and the discount rate constant at 30% and 15% respectively, I varied the selling price from 2.89 Rs./kWh to 7.00 Rs./kWh. As expected, both ROE and DSCR values show a steady upward trend as selling price has increased. The results of my analysis are presented in Figures 5.3 and 5.4.

At 2.89 Rs./kWh, all four projects are clearly not feasible—the hydro and coal projects actually showing negative ROE values. At 4.00 Rs./kWh, the diesel plants become feasible, while the hydro and coal plants are feasible only at 6.50 Rs./kWh and 5.50 Rs./kWh, respectively.

(II) Varying the Discount Rate

I first varied the discount rate from 8% to 22%, holding the selling price and equity participation constant at 2.89 Rs./kWh, and 30% respectively. As expected, the ROE and DSCR values show a steady decrease with increasing discount rates. As evident from the results presented in Figures 5.5 and 5.6, none of the plants are feasible within this range of values.

Given these results, I repeated the above analysis, increasing the selling price to 3.50 Rs./kWh (still holding equity participation at 30%). Now, the first diesel plant became feasible for discount rates between 8% and 12%, and the second one became feasible for discount rates between 8% and 14%. The hydro and coal plants were not feasible for the range of values under consideration.

(III) Varying the Level of Equity Participation

The level of equity participation did not have as much impact on the feasibility of the projects as the other two variables, but this set of results were the most interesting. I first varied this level, holding the selling price and discount rate constant at 2.89 Rs./kWh, and 15% respectively. Although none of the plants were feasible within this range, the ROE and DSCR values showed an upward trend (which was much less dramatic than when the selling price and the discount rate were varied), as shown in Figures 5.7 and 5.8

Consequently, I repeated the analysis by using a constant selling price of 3.50 Rs./kWh (still holding equity participation at 30%). At this selling price the diesel plants showed a *downward* trend with increasing levels of equity participation (in direct contrast to the upward trend it showed for the lower selling price). The hydro and coal plants still showed the upward trend they had displayed for the lower selling price.

Now, the first diesel plant became feasible for equity participation levels between 20% and 50%, and the second one became feasible for equity participation levels between the whole range under consideration (20% and 60%). The hydro and coal plants were not feasible for the range of values under consideration.

**Figure 5.3: Return On Equity for the Various Plants for Different Selling Prices (Rs/kWh)**
(Equity Participation: 30%; Discount Rate:15%)

| Purchase Price (Rs./kWh) | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 | 5.50 | 6.00 | 6.50 | 7.00 |
|---|---|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | -11% | 9% | 24% | 36% | 47% | 56% | 65% | 73% | 81% | 88% |
| Diesel 40 MW, 15 year BOT | 3% | 17% | 29% | 41% | 51% | 60% | 68% | 76% | 84% | 91% |
| Kukule Hydro 70 MW, 15 year BOT | -11% | -3% | 4% | 9% | 14% | 19% | 23% | 27% | 30% | 34% |
| Coal 300 MW, 15 year BOT | -13% | -1% | 8% | 14% | 20% | 26% | 30% | 34% | 38% | 41% |
| Required level | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |

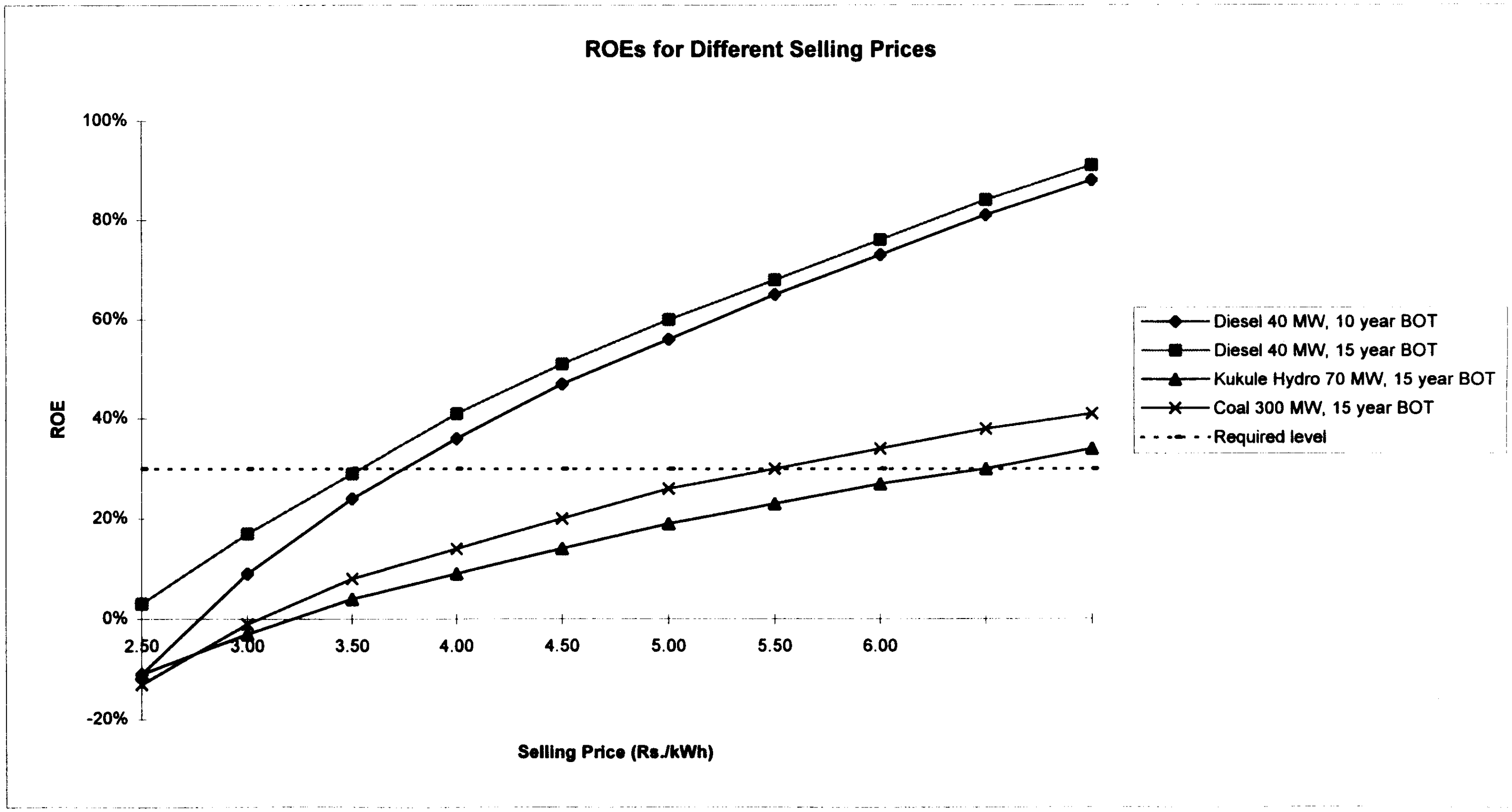


**Figure 5.5: Return On Equity for the Various Plants for Different Discount Rates**
(Selling Price: 2.89 Rs.kWh; Equity Participation: 30%)

| Discount Rate | 8% | 10% | 12% | 14% | 16% | 18% | 20% | 22% |
|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 20% | 16% | 12% | 8% | 3% | -1% | -6% | -10% |
| Diesel 40 MW, 15 year BOT | 27% | 24% | 20% | 16% | 12% | 8% | 4% | 1% |
| Kukule Hydro 70 MW, 15 year BOT | 9% | 5% | 1% | -3% | -6% | -10% | -14% | -17% |
| Coal 300 MW, 15 year BOT | 11% | 7% | 3% | -1% | -5% | -9% | -14% | -17% |
| Required level | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |

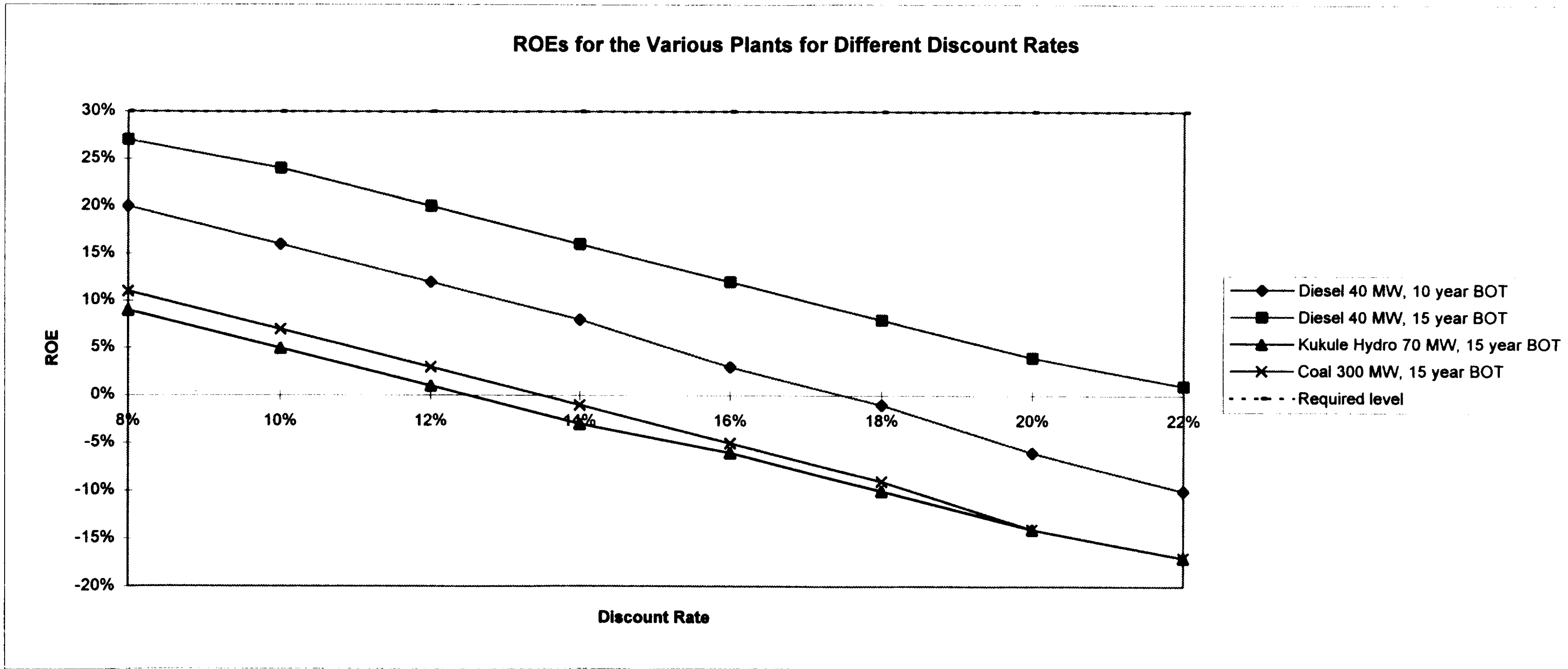


**Figure 5.4: Debt Service Coverage Ratios for the Various Plants for Different Selling Prices (Rs/kWh)**
(Equity Participation: 30%; Discount Rate:15%)

| Purchase Price (Rs./kWh) | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 | 5.50 | 6.00 | 6.50 | 7.00 |
|---|---|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 0.90 | 1.20 | 1.50 | 1.80 | 2.09 | 2.39 | 2.69 | 2.99 | 3.29 | 3.59 |
| Diesel 40 MW, 15 year BOT | 1.03 | 1.37 | 1.71 | 2.05 | 2.40 | 2.74 | 3.08 | 3.42 | 3.76 | 4.10 |
| Kukule Hydro 70 MW, 15 year BOT | 0.72 | 0.86 | 1.01 | 1.15 | 1.30 | 1.44 | 1.59 | 1.73 | 1.88 | 2.02 |
| Coal 300 MW, 15 year BOT | 0.65 | 0.85 | 1.05 | 1.25 | 1.45 | 1.65 | 1.85 | 2.05 | 2.25 | 2.45 |
| Required level | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |

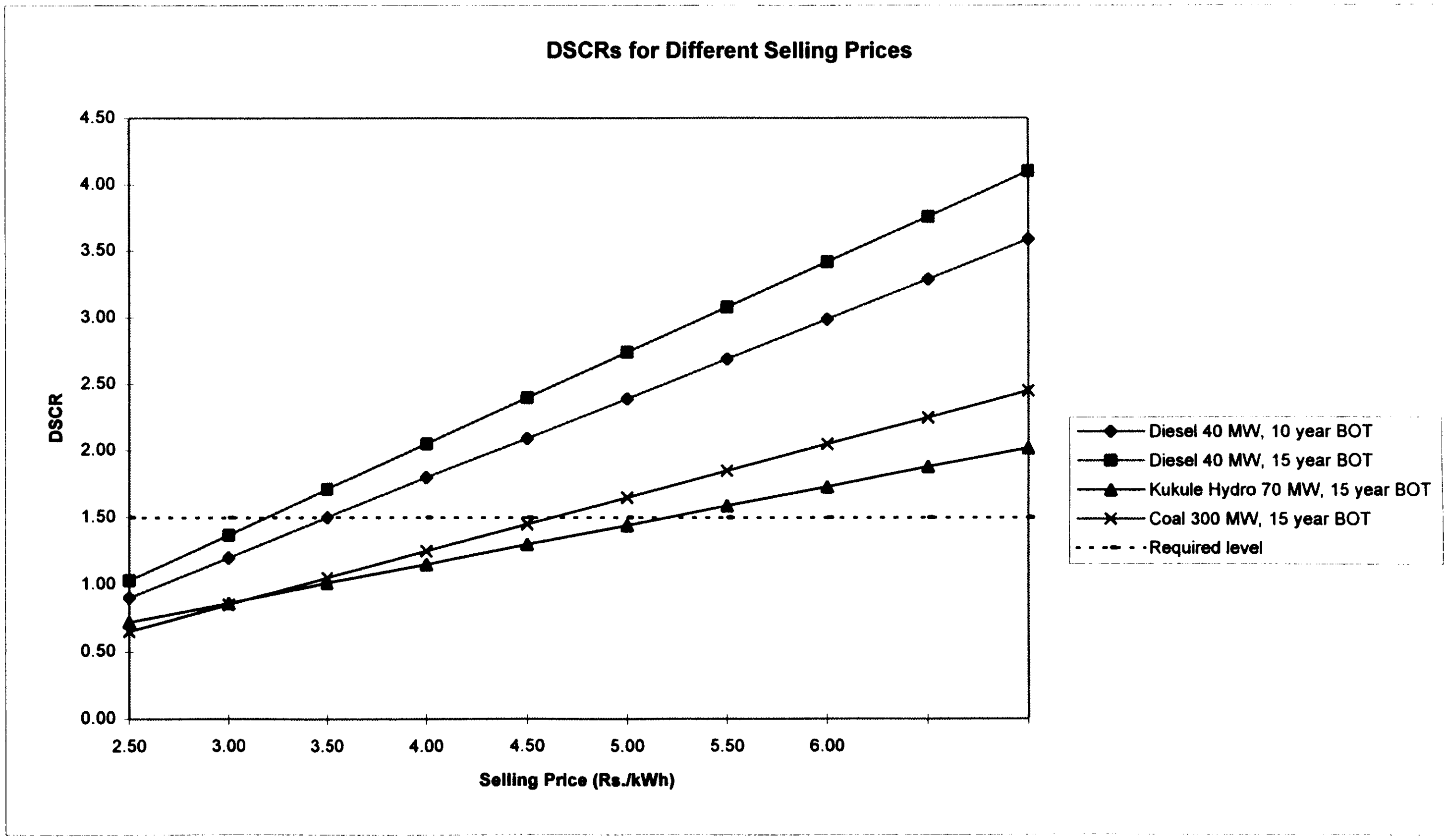


**Figure 5.6: Debt Service Coverage Ratios for the Various Plants for Different Discount Rates**
(Selling Price: 2.89 Rs.kWh; Equity Participation: 30%)

| Discount Rate | 8% | 10% | 12% | 14% | 16% | 18% | 20% | 22% |
|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 1.66 | 1.48 | 1.32 | 1.19 | 1.08 | 0.98 | 0.89 | 0.81 |
| Diesel 40 MW, 15 year BOT | 2.06 | 1.79 | 1.56 | 1.38 | 1.22 | 1.09 | 0.98 | 0.88 |
| Kukule Hydro 70 MW, 15 year BOT | 1.38 | 1.18 | 1.02 | 0.89 | 0.78 | 0.69 | 0.61 | 0.55 |
| Coal 300 MW, 15 year BOT | 1.46 | 1.22 | 1.03 | 0.87 | 0.75 | 0.65 | 0.57 | 0.50 |
| Required level | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |

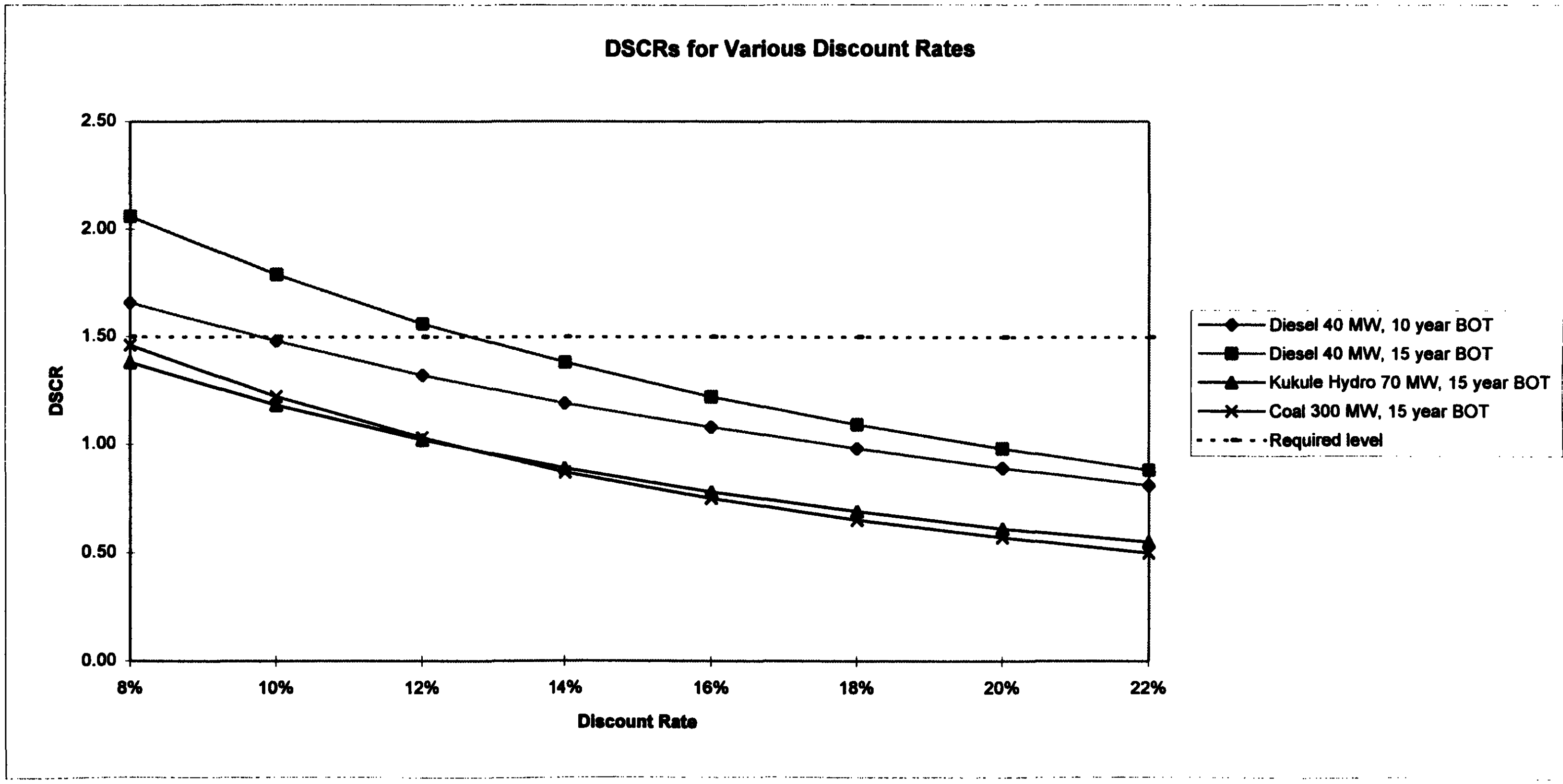


**Figure 5.7:Return On Equity for the Various Plants for Different Levels of Equity Participation**
(Selling Price: 2.89 Rs./kWh; Discount Rate: 15%)

| Equity Participation Level | 20% | 25% | 30% | 35% | 40% | 45% | 50% | 55% | 60% |
|---|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 2% | 4% | 6% | 7% | 8% | 9% | 9% | 10% | 10% |
| Diesel 40 MW, 15 year BOT | 13% | 14% | 14% | 14% | 14% | 15% | 15% | 15% | 15% |
| Kukule Hydro 70 MW, 15 year BOT | -7% | -6% | -4% | -3% | -2% | -1% | 0% | 0% | 1% |
| Coal 300 MW, 15 year BOT | -8% | -5% | -3% | -1% | 1% | 2% | 3% | 5% | 6% |
| Required level | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |

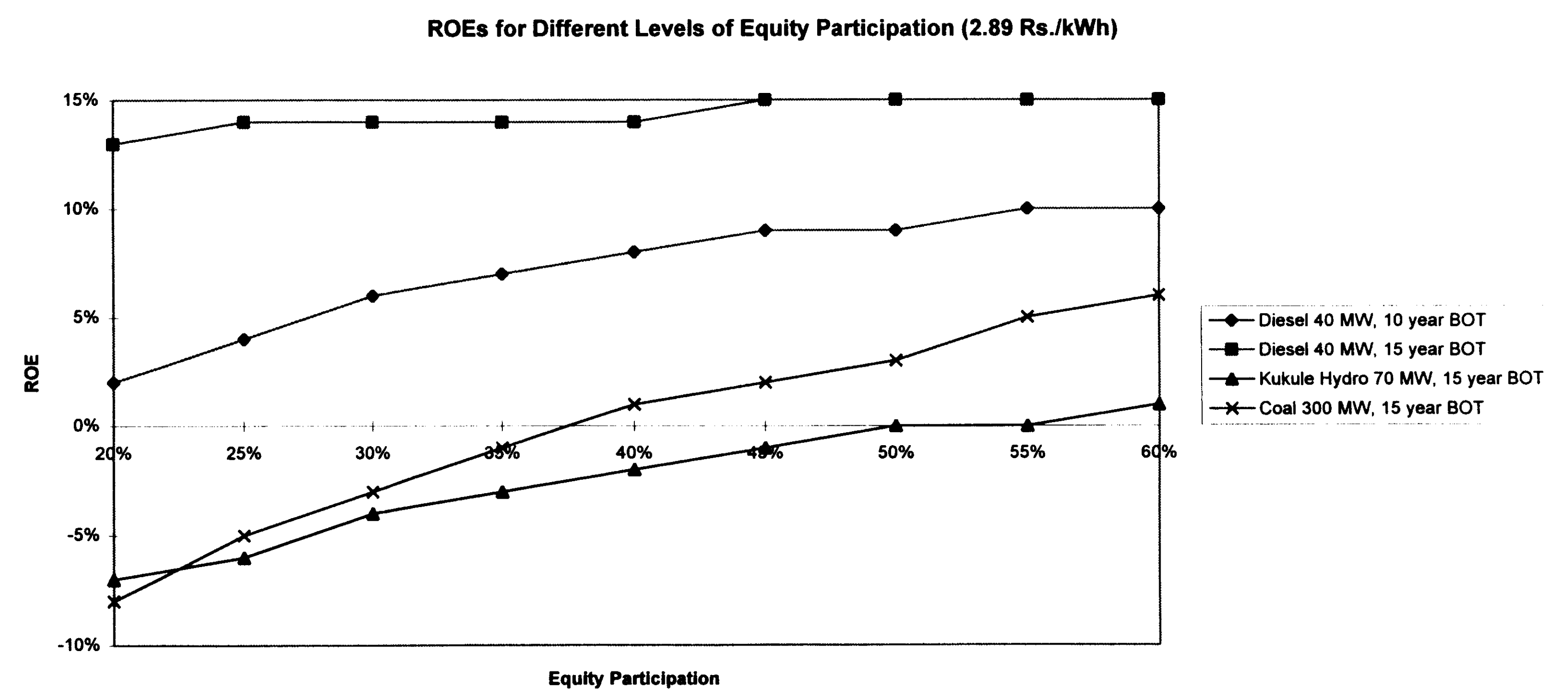
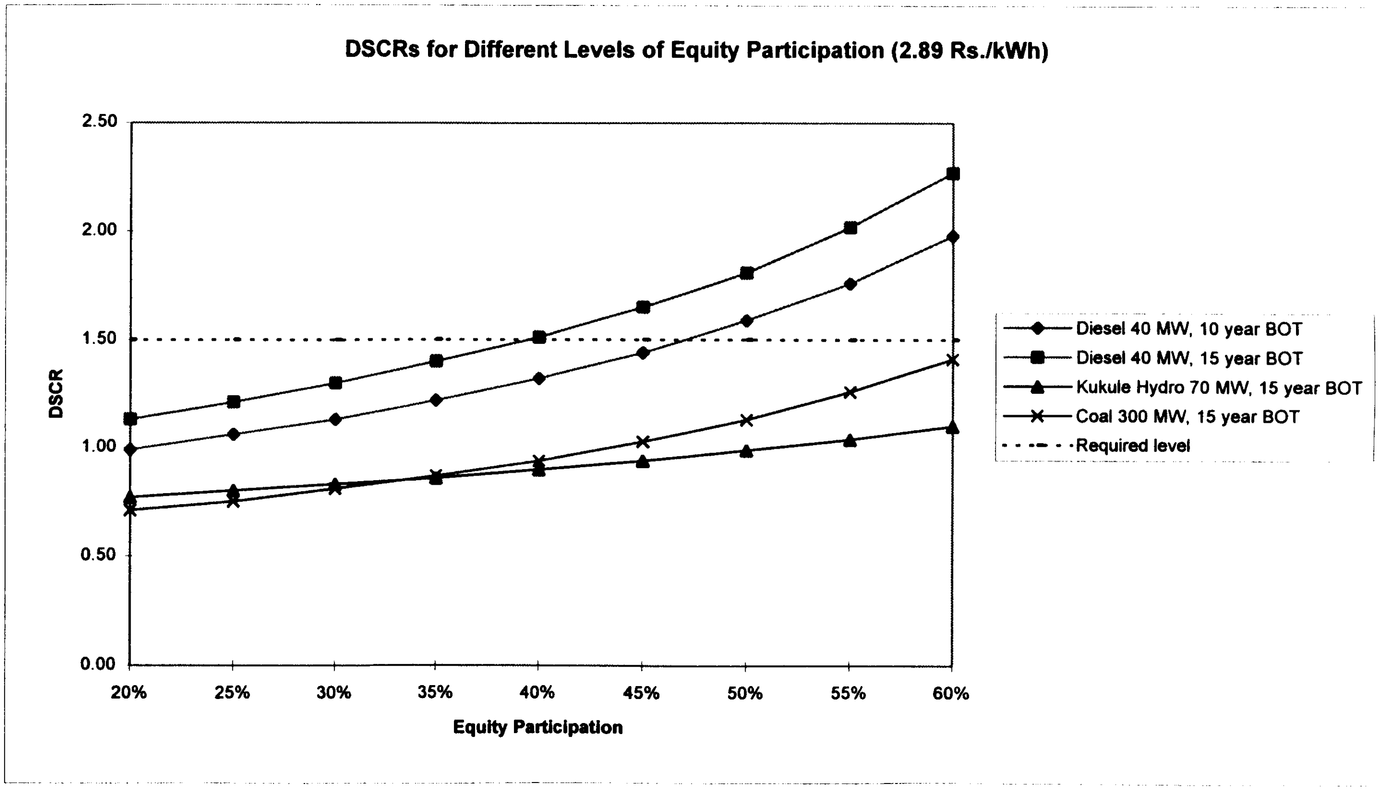


**Figure 5.8: Debt Service Coverage Ratios for the Various Plants for Different Levels of Equity Participation**
(Selling Price: 2.89 Rs./kWh; Discount Rate: 15%)

| Equity Participation Level | 20% | 25% | 30% | 35% | 40% | 45% | 50% | 55% | 60% |
|---|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 0.99 | 1.06 | 1.13 | 1.22 | 1.32 | 1.44 | 1.59 | 1.76 | 1.98 |
| Diesel 40 MW, 15 year BOT | 1.13 | 1.21 | 1.30 | 1.40 | 1.51 | 1.65 | 1.81 | 2.02 | 2.27 |
| Kukule Hydro 70 MW, 15 year BOT | 0.77 | 0.80 | 0.83 | 0.86 | 0.90 | 0.94 | 0.99 | 1.04 | 1.10 |
| Coal 300 MW, 15 year BOT | 0.71 | 0.75 | 0.81 | 0.87 | 0.94 | 1.03 | 1.13 | 1.26 | 1.41 |
| Required level | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |



### *5.10.2 Changing Two Variables at a Time*

(I) Discount Rate and Selling Price

Holding the equity participation level at 30%, I varied the discount rate and the selling prices from 8% to 20%, and 2.50 to 5.00 Rs./kWh. The results of this analyses are presented in the matrices in Tables 5.13 and 5.14 which show the respective ROEs and DSCR values.

This analysis gives a better indication of the sets of conditions that must be satisfied, in order for the various plants to be feasible for the private developer (the feasible ROE and DSCR values have been shaded in the respective matrices). For example, the 40 MW, 10 year Diesel plant gradually becomes feasible in the upper-right hand corner of the matrix (as expected, due to increasing selling prices, and reducing discount rates).

All the other plants show the same tendency of becoming more feasible (measured by both ROE and DSCR) at the upper right hand corner of the matrices. The diesel and coal plants become feasible for the discount rate-selling price combinations under consideration, but the hydro plant does not.

(II) Selling Price and Equity Participation

In this analysis, I obtained ROE and DSCR values for different selling price and equity participation rate combinations, holding the discount rate constant at 15%. I varied the selling price from 2.50 to 5.00 Rs./kWh, and the equity participation rates from 20% to 50%. The results are presented in Tables 5.15 and 5.16 where the feasible ROE and DCSR values have been shaded.

In this case (as in the previous case), the projects become increasingly feasible (measured by both ROE and DSCR) as the selling prices and the equity participation rates increase (in the upper right hand corner of the matrices).

(III) Discount Rate and Equity Participation

Here, I varied the discount rate and equity participation levels from 8% to 18% and 20% to 50%, holding the selling price constant (the results are presented in Tables 5.17 and 5.18). Since there are few feasible scenarios at the base selling price of 2.89 Rs./kWh, I repeated the analysis for selling prices of 3.00 and 3.50 Rs./kWh (which increased the number of feasible scenarios).

In this analysis, surprisingly, the ROE and DSCR values became increasingly feasible according to two entirely different patterns (the results are presented in Appendix 6). For all three selling prices, the ROE values became increasingly feasible with decreasing discount rates and decreasing equity participation rates (in the upper left hand corner of the matrices). In contrast, the DSCR values became more feasible for decreasing ROE values and *increasing* equity participation rates (in the *lower* left hand corner of the matrices). Therefore, the feasible projects, would be where the shaded portions of both sets of matrices (for both ROE values and DSCR values) overlapped.

Table 5.13

**ROEs for Different Discount Rates and Selling Prices (Equity Participation: 30%)**

**Diesel 40 MW, 10 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 7% | 23% | 36% | 47% | 57% | 66% |
| **10%** | 2% | 20% | 33% | 44% | 55% | 64% |
| **12%** | -3% | 16% | 30% | 41% | 52% | 61% |
| **14%** | -8% | 12% | 26% | 38% | 48% | 58% |
| **16%** | -13% | 7% | 22% | 34% | 45% | 55% |
| **18%** | -18% | 3% | 18% | 31% | 42% | 52% |
| **20%** | -23% | -2% | 14% | 27% | 38% | 48% |

**Diesel 40 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 17% | 30% | 42% | 52% | 61% | 70% |
| **10%** | 13% | 26% | 38% | 49% | 58% | 67% |
| **12%** | 9% | 23% | 35% | 46% | 55% | 64% |
| **14%** | 5% | 19% | 31% | 42% | 52% | 61% |
| **16%** | 1% | 15% | 27% | 39% | 49% | 58% |
| **18%** | -3% | 11% | 24% | 35% | 45% | 55% |
| **20%** | -6% | 7% | 20% | 31% | 42% | 51% |

**Hydro 70 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 3% | 10% | 16% | 21% | 25% | 29% |
| **10%** | -1% | 7% | 12% | 18% | 22% | 26% |
| **12%** | -5% | 3% | 9% | 14% | 19% | 23% |
| **14%** | -9% | -1% | 5% | 11% | 16% | 20% |
| **16%** | -13% | -5% | 2% | 7% | 12% | 17% |
| **18%** | -17% | -8% | -2% | 4% | 9% | 14% |
| **20%** | -21% | -12% | -5% | 0% | 5% | 10% |

**Coal 300 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 4% | 13% | 26% | 25% | 30% | 35% |
| **10%** | -1% | 9% | 17% | 23% | 28% | 32% |
| **12%** | -6% | 5% | 13% | 20% | 25% | 30% |
| **14%** | -10% | 1% | 9% | 16% | 22% | 27% |
| **16%** | -15% | -3% | 6% | 13% | 19% | 24% |
| **18%** | -20% | -7% | 2% | 9% | 15% | 21% |
| **20%** | -25% | -11% | -2% | 5% | 12% | 17% |

Note:
The options which meet the minimum requirements have been shaded

Table 5.14

**DSCRs for Different Discount Rates and Selling Prices (Equity Participation: 30%)**

**Diesel 40 MW, 10 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 1.32 | 1.75 | 2.19 | 2.63 | 3.07 | 3.50 |
| **10%** | 1.17 | 1.56 | 1.95 | 2.34 | 2.73 | 3.12 |
| **12%** | 1.05 | 1.40 | 1.75 | 2.10 | 2.45 | 2.80 |
| **14%** | 0.95 | 1.26 | 1.57 | 1.89 | 2.20 | 2.52 |
| **16%** | 0.86 | 1.14 | 1.42 | 1.71 | 1.99 | 2.28 |
| **18%** | 0.78 | 1.03 | 1.29 | 1.55 | 1.81 | 2.07 |
| **20%** | 0.71 | 0.94 | 1.18 | 1.41 | 1.65 | 1.88 |

**Diesel 40 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 1.64 | 2.18 | 2.73 | 3.27 | 3.82 | 4.36 |
| **10%** | 1.42 | 1.89 | 2.38 | 2.84 | 3.31 | 3.78 |
| **12%** | 1.24 | 1.65 | 2.07 | 2.48 | 2.89 | 3.30 |
| **14%** | 1.09 | 1.46 | 1.82 | 2.18 | 2.55 | 2.91 |
| **16%** | 0.97 | 1.29 | 1.61 | 1.94 | 2.26 | 2.58 |
| **18%** | 0.87 | 1.15 | 1.44 | 1.73 | 2.02 | 2.30 |
| **20%** | 0.78 | 1.04 | 1.29 | 1.55 | 1.81 | 2.07 |

**Hydro 70 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 1.19 | 1.44 | 1.68 | 1.92 | 2.16 | 2.41 |
| **10%** | 1.02 | 1.23 | 1.43 | 1.64 | 1.85 | 2.06 |
| **12%** | 0.88 | 1.06 | 1.24 | 1.42 | 1.59 | 1.77 |
| **14%** | 0.77 | 0.92 | 1.08 | 1.23 | 1.39 | 1.54 |
| **16%** | 0.67 | 0.81 | 0.94 | 1.08 | 1.22 | 1.35 |
| **18%** | 0.59 | 0.71 | 0.83 | 0.95 | 1.07 | 1.19 |
| **20%** | 0.53 | 0.63 | 0.74 | 0.85 | 0.95 | 1.06 |

**Coal 300 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **8%** | 1.18 | 1.54 | 1.90 | 2.27 | 2.63 | 2.99 |
| **10%** | 0.98 | 1.28 | 1.59 | 1.89 | 2.19 | 2.49 |
| **12%** | 0.83 | 1.08 | 1.34 | 1.59 | 1.84 | 2.10 |
| **14%** | 0.70 | 0.92 | 1.14 | 1.35 | 1.57 | 1.78 |
| **16%** | 0.60 | 0.79 | 0.97 | 1.16 | 1.35 | 1.53 |
| **18%** | 0.52 | 0.68 | 0.84 | 1.00 | 1.16 | 1.32 |
| **20%** | 0.46 | 0.60 | 0.74 | 0.88 | 1.02 | 1.16 |

Note:
The options which meet the minimum requirements have been shaded

Table 5.15

**ROEs for Different Selling Prices and Equity Participation Rates (Discount Rate:15%)**

**Diesel 40 MW, 10 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **20%** | -20% | 7% | 27% | 43% | 57% | 70% |
| **25%** | -15% | 8% | 25% | 39% | 51% | 62% |
| **30%** | -11% | 9% | 24% | 36% | 47% | 56% |
| **35%** | -7% | 10% | 23% | 34% | 44% | 52% |
| **40%** | -4% | 11% | 22% | 32% | 41% | 49% |
| **45%** | -2% | 11% | 22% | 31% | 39% | 46% |
| **50%** | 0% | 12% | 21% | 30% | 37% | 44% |

**Diesel 40 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **20%** | -1% | 17% | 34% | 49% | 62% | 75% |
| **25%** | 1% | 17% | 31% | 44% | 56% | 66% |
| **30%** | 3% | 17% | 29% | 41% | 51% | 60% |
| **35%** | 4% | 17% | 28% | 38% | 47% | 55% |
| **40%** | 5% | 17% | 27% | 36% | 44% | 51% |
| **45%** | 6% | 17% | 26% | 34% | 41% | 48% |
| **50%** | 7% | 17% | 25% | 33% | 40% | 46% |

**Hydro 70 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **20%** | -14% | -5% | 2% | 8% | 14% | 19% |
| **25%** | -13% | -4% | 3% | 9% | 14% | 19% |
| **30%** | -11% | -3% | 4% | 9% | 14% | 19% |
| **35%** | -9% | -2% | 4% | 9% | 14% | 18% |
| **40%** | -8% | -1% | 5% | 10% | 14% | 18% |
| **45%** | -7% | 0% | 6% | 10% | 14% | 18% |
| **50%** | -5% | 1% | 6% | 10% | 14% | 18% |

**Coal 300 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| **20%** | -20% | -5% | 5% | 14% | 21% | 28% |
| **25%** | -16% | -3% | 6% | 14% | 21% | 27% |
| **30%** | -13% | -1% | 8% | 14% | 20% | 26% |
| **35%** | -10% | 1% | 9% | 15% | 20% | 25% |
| **40%** | -7% | 2% | 9% | 15% | 20% | 24% |
| **45%** | -5% | 4% | 10% | 15% | 20% | 23% |
| **50%** | -3% | 5% | 11% | 15% | 19% | 23% |

Note:
The options which meet the minimum requirements have been shaded

Table 5.16

**DSCRs for Different Selling Prices and Equity Participation Rates (Discount Rate:15%)**

**Diesel 40 MW, 10 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| 20% | 0.79 | 1.05 | 1.31 | 1.57 | 1.83 | 2.09 |
| 25% | 0.84 | 1.12 | 1.40 | 1.68 | 1.95 | 2.23 |
| 30% | 0.90 | 1.20 | 1.50 | 1.80 | 2.09 | 2.39 |
| 35% | 0.97 | 1.29 | 1.61 | 1.93 | 2.25 | 2.58 |
| 40% | 1.05 | 1.40 | 1.75 | 2.09 | 2.44 | 2.79 |
| 45% | 1.14 | 1.52 | 1.90 | 2.28 | 2.66 | 3.04 |
| 50% | 1.26 | 1.68 | 2.10 | 2.51 | 2.93 | 3.35 |

**Diesel 40 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| 20% | 0.90 | 1.20 | 1.50 | 1.80 | 2.10 | 2.40 |
| 25% | 0.98 | 1.28 | 1.60 | 1.92 | 2.24 | 2.55 |
| 30% | 1.03 | 1.37 | 1.71 | 2.05 | 2.40 | 2.74 |
| 35% | 1.11 | 1.48 | 1.84 | 2.21 | 2.58 | 2.95 |
| 40% | 1.20 | 1.60 | 2.00 | 2.40 | 2.80 | 3.19 |
| 45% | 1.31 | 1.74 | 2.18 | 2.61 | 3.05 | 3.48 |
| 50% | 1.44 | 1.92 | 2.40 | 2.88 | 3.35 | 3.83 |

**Hydro 70 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| 20% | 0.66 | 0.80 | 0.93 | 1.07 | 1.20 | 1.34 |
| 25% | 0.69 | 0.83 | 0.97 | 1.11 | 1.25 | 1.39 |
| 30% | 0.72 | 0.86 | 1.01 | 1.15 | 1.30 | 1.44 |
| 35% | 0.75 | 0.90 | 1.05 | 1.20 | 1.35 | 1.50 |
| 40% | 0.78 | 0.94 | 1.10 | 1.25 | 1.41 | 1.57 |
| 45% | 0.82 | 0.98 | 1.15 | 1.31 | 1.48 | 1.64 |
| 50% | 0.86 | 1.03 | 1.20 | 1.38 | 1.55 | 1.72 |

**Coal 300 MW, 15 Year BOT**

| | 2.50 | 3.00 | 3.50 | 4.00 | 4.50 | 5.00 |
|---|---|---|---|---|---|---|
| 20% | 0.57 | 0.75 | 0.92 | 1.09 | 1.27 | 1.44 |
| 25% | 0.61 | 0.79 | 0.98 | 1.17 | 1.35 | 1.54 |
| 30% | 0.65 | 0.85 | 1.05 | 1.25 | 1.45 | 1.65 |
| 35% | 0.70 | 0.92 | 1.13 | 1.35 | 1.56 | 1.78 |
| 40% | 0.76 | 0.99 | 1.23 | 1.46 | 1.69 | 1.92 |
| 45% | 0.83 | 1.08 | 1.34 | 1.59 | 1.85 | 2.10 |
| 50% | 0.91 | 1.19 | 1.47 | 1.75 | 2.03 | 2.31 |

Note:
The options which meet the minimum requirements have been shaded

Table 5.17

**ROEs for Different Discount Rates and Equity Participation Rates (Selling Price 2.89 Rs./kWh)**

**Diesel 40 MW, 10 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 25% | 18% | 12% | 5% | -1% | -7% |
| 25% | 22% | 17% | 12% | 7% | 1% | -4% |
| 30% | 20% | 16% | 12% | 8% | 3% | -1% |
| 35% | 19% | 16% | 12% | 9% | 5% | 1% |
| 40% | 18% | 15% | 12% | 9% | 6% | 3% |
| 45% | 17% | 15% | 12% | 10% | 7% | 5% |
| 50% | 16% | 14% | 12% | 10% | 8% | 6% |

**Diesel 40 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 34% | 28% | 22% | 16% | 10% | 5% |
| 25% | 30% | 26% | 21% | 16% | 11% | 7% |
| 30% | 27% | 24% | 20% | 16% | 12% | 8% |
| 35% | 25% | 22% | 19% | 16% | 13% | 9% |
| 40% | 23% | 21% | 19% | 16% | 13% | 10% |
| 45% | 22% | 20% | 18% | 16% | 14% | 11% |
| 50% | 21% | 19% | 18% | 16% | 14% | 12% |

**Hydro 70 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 9% | 4% | 0% | -5% | -9% | -13% |
| 25% | 9% | 5% | 1% | -4% | -8% | -12% |
| 30% | 9% | 5% | 1% | -3% | -6% | -10% |
| 35% | 9% | 5% | 2% | -2% | -5% | -8% |
| 40% | 9% | 6% | 3% | -1% | -4% | -7% |
| 45% | 9% | 6% | 3% | 0% | -3% | -6% |
| 50% | 9% | 6% | 4% | 1% | -2% | -5% |

**Coal 300 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 12% | 6% | 0% | -5% | -10% | -15% |
| 25% | 11% | 7% | 2% | -3% | -8% | -12% |
| 30% | 11% | 7% | 3% | -1% | -5% | -9% |
| 35% | 11% | 8% | 4% | 1% | -3% | -7% |
| 40% | 11% | 8% | 5% | 2% | -1% | -4% |
| 45% | 11% | 9% | 6% | 4% | 1% | -2% |
| 50% | 11% | 9% | 7% | 5% | 2% | 0% |

Note:
The options which meet the minimum requirements have been shaded

Table 5.18

**DSCRs for Different Discount Rates and Equity Participation Rates (Selling Price 2.89 Rs./kWh)**

**Diesel 40 MW, 10 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.45 | 1.29 | 1.16 | 1.04 | 0.94 | 0.86 |
| 25% | 1.55 | 1.38 | 1.24 | 1.11 | 1.01 | 0.91 |
| 30% | 1.66 | 1.48 | 1.32 | 1.19 | 1.08 | 0.98 |
| 35% | 1.79 | 1.59 | 1.43 | 1.28 | 1.16 | 1.05 |
| 40% | 1.93 | 1.72 | 1.54 | 1.39 | 1.26 | 1.14 |
| 45% | 2.11 | 1.88 | 1.69 | 1.52 | 1.37 | 1.24 |
| 50% | 2.32 | 2.07 | 1.85 | 1.67 | 1.51 | 1.37 |

**Diesel 40 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.81 | 1.57 | 1.37 | 1.21 | 1.07 | 0.95 |
| 25% | 1.93 | 1.67 | 1.46 | 1.29 | 1.14 | 1.02 |
| 30% | 2.06 | 1.79 | 1.56 | 1.38 | 1.22 | 1.09 |
| 35% | 2.22 | 1.93 | 1.68 | 1.48 | 1.32 | 1.17 |
| 40% | 2.41 | 2.09 | 1.82 | 1.61 | 1.43 | 1.27 |
| 45% | 2.63 | 2.28 | 1.99 | 1.75 | 1.55 | 1.39 |
| 50% | 2.89 | 2.51 | 2.19 | 1.93 | 1.71 | 1.53 |

**Hydro 70 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.28 | 1.09 | 0.94 | 0.82 | 0.72 | 0.64 |
| 25% | 1.33 | 1.14 | 0.98 | 0.85 | 0.75 | 0.66 |
| 30% | 1.38 | 1.18 | 1.02 | 0.89 | 0.78 | 0.69 |
| 35% | 1.44 | 1.23 | 1.06 | 0.92 | 0.81 | 0.72 |
| 40% | 1.50 | 1.29 | 1.11 | 0.97 | 0.85 | 0.75 |
| 45% | 1.57 | 1.34 | 1.16 | 1.01 | 0.89 | 0.78 |
| 50% | 1.65 | 1.41 | 1.22 | 1.06 | 0.93 | 0.82 |

**Coal 300 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.28 | 1.07 | 0.90 | 0.76 | 0.66 | 0.57 |
| 25% | 1.37 | 1.14 | 0.96 | 0.81 | 0.70 | 0.61 |
| 30% | 1.46 | 1.22 | 1.03 | 0.87 | 0.75 | 0.65 |
| 35% | 1.58 | 1.31 | 1.10 | 0.94 | 0.81 | 0.70 |
| 40% | 1.71 | 1.42 | 1.20 | 1.02 | 0.87 | 0.76 |
| 45% | 1.86 | 1.55 | 1.31 | 1.11 | 0.95 | 0.83 |
| 50% | 2.05 | 1.71 | 1.44 | 1.22 | 1.05 | 0.91 |

Note:
The options which meet the minimum requirements have been shaded

# CHAPTER 6

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## Recommendations

In the preceding chapters I explored some of the major problems concerning the Sri Lankan government, its power planners, and policy makers in related areas. The main issue which has to be addressed immediately is how essential capacity will be constructed and funded. Although the government has considered the innovative BOT scheme which has been gaining considerable attention in the region in recent years, it is evident that there needs to be a much greater understanding of the process as well as the essential steps that need to be taken to make this effort a success. The fact that no single project is in progress, even though a few specific ones have been talked about, is evidence of this. The recent power cuts that have been introduced in Sri Lanka further underline the urgency for immediate action on the part of the government.

In light of the discussion in the preceding chapters, I will now present some recommendations for the Sri Lankan government and policy makers in the energy sector. I will first outline some of my main observations about the country's power sector, and then indicate what must be done to attract private power generation while keeping the needs of consumers in mind. Finally, I will present approaches to deal with the crisis, which do not focus exclusively on building additional generating plants.

## 6.1 Observations on the Sri Lankan Power Situation and Recommendations for Power Planners

- Investment requirements between 1995 and 2000 for new power generating facilities would exceed $1100 million if the demand for electricity develops at the predicted rate of 7.9% per year.
- The mix of generating plants and their commissioning periods should closely follow a carefully thought out optimum generation expansion plan. This plan should, however, be flexible enough to deal with unexpected future events. (The current CEB Long Term Generation Expansion Plan 1995-2009 is a good first step, but this can be improved by more sophisticated modeling schemes which explore more future scenarios).
- Financing of power generation projects through soft loans have been of overall benefit to the economy. Therefore, maximum effort must be made to continue to secure such finances for future projects.
- In the event that soft or concessionary terms for financing of power sector projects are not forthcoming (as probably will be the case), or if the international lending agencies would not participate in purely state-owned utility projects, it would be necessary to establish utility-private sector partnerships to develop the power generating system in the future.
- Joint projects, or solely private development of power generating capacity, should continue to be based on overall system least-cost principles so that the cost of electricity to the consumer will be maintained at the lowest possible level. It is important to make sure that the private sector is neither subsidized nor penalized.
- The predominantly hydroelectric power generating system in Sri Lanka should be operated on least-cost principles with no generating plants operating as "must-run" units (as is sometimes the case at present). Only the merit order loading system, with a free hand to the system dispatcher, and with no

restrictions imposed on generating plant operations, would guarantee the maximum benefit of the hydro system to the national economy.

- As described earlier, many of the nation's hydroelectricity projects are part of large multi-purpose schemes. The government should take further steps to coordinate irrigation needs and power generation in order to reduce some of the present inefficiencies that arise in these projects. It should also make concerted efforts to reduce the huge losses in the system.

### 6.2 The Process of Privatization

The execution of privatization transactions is the last step in a long and often complex process[1]. When state assets are privatized, a variety of social and political issues come to the surface. The transaction should be consciously pursued in a way that addresses these competing interests and gains the support of important groups. At the same time, privatization may also require substantial preparation, particularly because the complex energy sector may often have to be substantially restructured for the divestiture to be successful.

The essential first step in the privatization process is to define the goals of the program as a whole and the political, economic, and social goals of each transaction. By defining these goals early and incorporating them into the planning and execution of each stage of the privatization process, the program can move forward with direction and focus, increasing the likelihood that the goals will be achieved.

While formulating these goals, planners should identify the interests of the main groups likely to be affected by the process. The following section outlines the principle stakeholders as well as the interests expressed by the stakeholder groups in the privatizations White & Case (a law firm involved in privatization of national oil companies, mainly in the Middle East) have been involved[2]:

[1] Petroleum Economist Ltd. (in association with Andersen Consulting), The Guide to World Energy Privatization (London, United Kingdom: March 1995), p.3
[2] Petroleum Economist Ltd., The Guide to World Energy Privatization, p.30

Government

- Prohibit monopolization/encourage sound growth of economy through provision of competitively-priced electricity.
- Maximize earnings from the sale of existing utilities
- Create an economically viable entity (especially at the end of the lease of BOT projects)
- Address environmental and pollution concerns
- Obtain access to world-class technology and marketing organizations, thereby increasing the economic viability of the privatized entity and maximizing its contribution to the national economy

Company Management

- Participate in the privatization decision-making process
- Maintain employment in the privatized company
- Negotiate a satisfactory salary and benefits package
- Participate in stock ownership plans
- Provide opportunity to participate in growth and success of privatized entity

Employees

- Maintain employment in the privatized company
- Negotiate a satisfactory salary and benefits package
- Participate in stock ownership plans
- Create opportunity to participate in growth and success of privatized entity

Trade Unions

- Ensure that union members do not lose their jobs
- Negotiate a satisfactory salary and benefits package for union members
- Maintain influence in privatized company

Consumers

- Avoid price increases in electricity
- Create a consumer-oriented company that is responsive to the needs of consumers
- Address concerns about foreign "control" or "domination" of a key industry

Strategic Investors

- Active management role (though not necessarily majority equity stake) in company
- Limited regulation by government (e.g., price controls, strategic stocks, realistic environmental objectives)
- Clearly defined regulatory framework
- Potential risk factors that may affect business and profitability (e.g., political stability, foreign-exchange restrictions, level of government involvement).
- Anticipated return on investment, based on, among other things, overall energy demand, market share of company, level of competition and structuring of feedstock and product offtake arrangements
- Freedom from liability for pre-existing environmental conditions
- Commitment from government that import restrictions and/or tariffs will be kept in place
- "Compatibility" issues, including corporate culture, management style, and geographic considerations.

Minority shareholders

- Corporate structure that protects the rights of shareholders

Although power planners cannot satisfy all of the needs of the above stakeholders, it is important that the planners be aware of the various views of the different interest groups. This attentiveness will enable the government to address and deal with potential opposition to their privatization plans.

### *6.2.1 Barriers to Private Sector Participation in Sri Lanka*

There are a couple of major barriers to private sector participation in the Sri Lankan power generating sector. These include institutional deficiencies, CEB's concerns, and uncertainties regarding cost recovery.

Institutional Deficiencies

Two main institutional deficiencies are evident in Sri Lanka's program to attract and secure private participation: a straightforward and clearly defined structure for gaining government approval, and a government entity with clear authority to move projects forward. As a result, private developers may have to approach as many as five government agencies or ministries to obtain approval for letters of intent, directives on unsolicited proposals, and decisions on solicited proposals[3] (World Energy Privatization, p.75)

CEB's Concerns

As the purchaser of private power, and owner of the system that would transmit this power, the CEB plays an instrumental role in the success of private-sector participation. However, the agency is concerned that unsolicited and hastily-evaluated proposals for smaller projects can have an adverse impact on long-range electricity tariff requirements. As a result of the CEB's unenthusiastic support for private power and the absence of a legally empowered government entity to promote these projects, key studies to establish the "buy-back" rate or avoided cost of energy for small- and intermediate-sized projects have been delayed.

[3] Petroleum Economist Ltd., The Guide to World Energy Privatization, p.75

Uncertainties Regarding Cost Recovery

Another significant obstacle to private participation is cost recovery. As the decision by lenders to finance a non-recourse or limited-recourse project is based primarily on the project's cash flows, tariff setting and collection should be economically sound. Tariffs should reflect the real cost of generating and transmitting electricity, and adjustment formulae should take into account changes in operating costs, as well as inflation and the exchange rate for local currency vis-à-vis a hard currency.

As stated before, power generation and transmission in Sri Lanka traditionally has been financed with government loans containing "soft" terms and conditions. Thus, existing tariffs do not reflect the actual cost of service. Like most utilities in other developing countries, those in Sri Lanka usually recover operating costs but only a very limited portion of capital costs. Compounding the tariff disparity is the fact that new, private projects are financed with more traditional lending terms, which include substantially higher interest rates and much shorter amortization periods.

Taken together, these factors mean that the resulting tariff increases necessary to support a commercially viable project can be prohibitive and politically unacceptable. To address this problem, developers, lenders and the government of Sri Lanka are looking at alternative sources for supplementary finance including: public/private sector financing, local debt market participation, bridge finance to mitigate construction risk, co-generation to spread costs, direct and indirect guarantees from the host government, and indexing payments for inflation factors.

### 6.2.2 *The Need to Balance Costs and Benefits of Private Power Generation*

The higher financing costs associated with private power projects must be balanced against the higher availability and reliability of the services these projects provide. Reducing power cutbacks significantly increases industrial output (a study in India has shown that the value of lost industrial output is roughly 18-times the value of lost power). The key to the superior performance of private power projects lies in the stronger incentives generated when sponsors and lenders have their own capital at risk and face performance-related incentives.

### 6.2.3 *Government Efforts to Facilitate Foreign Investment*

Recognizing the various barriers to private participation described above, the Sri Lankan government has recently made significant efforts to address some of these problems. Widespread regulatory reform and the establishment of financial intermediaries with the assistance of international development agencies are among the more important steps it has taken recently.

#### Regulatory Reform

The Sri Lankan Government set up the Board of Investment (BoI) as a "one-stop shop" for foreign investors, and legally endowed it with powers normally granted to other authorities (planning permission, for example) with respect to foreign investment projects.

New guidelines clarifying foreign investment incentives and procedures were published at the end of 1991. Foreign investment is now permitted in all sectors of the economy except for money lending, retail trade (if the investment is less than $1 million), brokering, coastal fishing, and personal services (except for export or tourism). There is a further list of regulated activities, including banking and insurance, where approval is given on a case-by-case basis by the appropriate regulatory authority.

Investment incentives, which are available to both domestic and foreign investors, are administered by the BoI. Until recently the incentives included a number of tax holidays, but these were criticized as unduly narrowing the tax base. In 1994 the holidays were effectively replaced by a concessionary tax rate of 15% in a move which also rationalized the incentive structure[4].

[4] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.48

The minimum investment required for infrastructure is $25 million for most projects. Concessions granted include: 15% preferential corporate tax rate for 20 years; duty-free import of project-related items; exemption from all exchange control regulations; free transferability of shares; and free repatriation of profits and capital proceeds[5].

Financial Intermediaries

The International Development Association (IDA), the soft loan arm of the World Bank, is assisting Sri Lanka in setting up a new financial intermediary, the Infrastructure Investment Fund Company (IIFC). The new company will act as an intermediary in the placement of long-term government guaranteed debt in suitable private sector infrastructure projects, primarily using BOT and BOO arrangements. The initial assets that the IIFC will manage will be in excess of US$ 100 million. The IDA will support the IIFC for an initial period of four years, after which it is expected to be self-supporting. The IIFC will have the responsibility of evaluating projects and recommending the placement of IIFC funds[6].

The Multilateral Investment Guarantee Agency (MIGA), which is affiliated with the World Bank and provides guarantees against the risks of war, civil disturbances, expropriation, breach of contract, and currency transfers, has also been looking for opportunities in Sri Lanka. MIGA was formed in 1988 by 42 World Bank member countries that subscribed to 53% of the agency's authorized capital of $1.08 billion[7]. Its aim is to encourage foreign investment in developing countries and offer advice to would-be recipient countries on how to make themselves more attractive. Of eight firms registering with the guarantee scheme, seven have been interested in power projects.

[5] Economist Intelligence Unit, Country Profile 1995-96: Sri Lanka, p.48
[6] Economist Intelligence Unit, Country Report, 4th Quarter 1995: Sri Lanka, p.21
[7] Economist Intelligence Unit, Country Report, 4th Quarter 1995: Sri Lanka, p.22

## 6.3 Further Steps Required to Encourage Private Generation, While Protecting the Public Interest

Although the Sri Lankan government instituted the above basic measures to encourage private investment and privatization, it still needs to do much in the specific area of the privatization of generation. The lack of adequate incentives is evident by the fact that the country still does not have even a single such scheme in place. In order to attract private investors, the government needs to create a suitable business environment by enacting both legislative and regulatory reform, as pointed out by a recent World Bank report[8].

### 6.3.1 *Legislative Reform*

Although it is not essential to have a comprehensive legal and regulatory framework for private sector power in order for a country to undertake private power projects[9], some basic legal provisions must be in force to attract private investors. These include basic provisions permitting private sector involvement in the electric power industry, obligating the existing utility to purchase power from private suppliers where it is economic to do so, and providing for the enforcement of contracts and settlement of disputes. Disputes should be resolved by clearly defined and equitable procedures or through binding arbitration. If the basic enabling legislation exists, private projects can be structured, and obligations can be clearly defined and established in contractual agreements among the power producer, the purchaser of power, and the government.

The development of the first private power projects in a host country can set the stage for the creation of a legal framework that is designed to attract investors and lenders to private power development. As the private sector role evolves, a

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[8] World Bank, Submission and Evaluation of Proposals for Private Power Generation Projects in Developing Countries, (Washington DC, USA: 1994), p.8
[9] World Bank, Submission and Evaluation of Proposals..., p.7

more comprehensive legal framework can be established. The laws should be simple and designed to cover the following basic requirements[10]:

- Responsibilities of ministries and government agencies for private power sector
- Utilities and power companies that will be subject to the law
- Issue of licenses, power franchises and trade restrictions
- Responsibilities, obligations, and rights of power purchasers
- Mechanisms for resolving disputes between the power purchaser and the project developer, owner, or operator
- Enforceability of contractual commitments
- Regulation and control of prices for sales of electricity
- Regulation of the terms and conditions of electric service
- Tax obligations of the private sector
- Objectives and scope of the law in terms of safety and environmental legislation
- Rights related to easements of land for power plants and transmission facilities
- Broad regulations for operation, labor relations, and management oversight

Even if basic in scope, the laws need to be clear. Legislation that gives government regulators excessive flexibility in approving new projects creates uncertainty for investors and developers, and this may deter or impede the privatization process.

### *6.3.2 Regulatory Reform*

As in the case of the legislative framework, an established regulatory structure is not a requirement for the development of private power projects, but the existence of one will probably accelerate the process. Normally in private power projects, the conditions and obligations of the power producer, purchaser, and host government are clearly defined in specific project documents, such as the implementation agreement and power purchase agreement. These define the relationship among the producer, purchaser, and host government and should

[10] World Bank, Submission and Evaluation of Proposals..., p.6

provide safeguards to protect the interests of all parties. The extent of these safeguards should be determined during the earliest phase of the project. However, the absence of clear regulations may prolong the negotiations, especially in countries where government officials do not have a proven background in private power development issues and where they may lack full authority to make decisions on behalf of the government. An effective regulatory environment can help to promote financially sound practices by utilities, and it can thereby increase investors' and lenders' confidence.

Governments should eventually institutionalize the regulatory process to reduce the number of conditions that need to be included in the contractual agreements for private power projects. Governments should also provide published procedures, including the specific steps and approvals needed for project processing. These should identify the agency (or agencies) in charge of permit and licensing procedures, as well as tariff policies, and should address other related issues. The key features of a sound regulatory framework include the following[11]:

- A transparent and open system
- Clearly articulated regulatory objectives, and wholesale and retail tariff setting mechanisms
- Clearly stated conditions which enable the market entry and exit of private companies
- A well-defined process for issuing private power project permits and licenses

Some countries may have an existing regulatory body that governs the electric power sector, but that entity may not be equipped to handle the approval of private power developments. Professional management, institutional independence, and a predictable pricing mechanism are essential characteristics of an effective regulatory function. The regulatory structure should ensure the financial viability and creditworthiness of utilities that are to purchase power from private producers.

[11] World Bank, Submission and Evaluation of Proposals..., p.7

If this is not done, investors and lenders are compelled to look to governments to provide assurances and guarantees.

# CONCLUSION

Sri Lanka's economy began developing rapidly after the introduction of the liberal, open, economic policy by the Jayawardene government in 1977. The country's growth rate of around 6 percent has been accompanied by a even higher growth in demand for electricity of 8 percent. It crucial that the government carefully plans how to meet this demand, because the World Bank and USAID reports, and other studies I examined, indicate that provision of necessary infrastructure (power in particular) is vital for a country's continued economic progress.

Increased government spending on defense because of the ongoing civil war in the north and east of the island, has put an enormous strain on the country's treasury. As indicated in Table 2.9, Sri Lanka's current account deficit in 1994 was ten percent of GDP. These budgetary difficulties, combined with increasing worldwide demand for a shrinking pool of development funds available through international lending agencies such as the World Bank, has made the raising and disbursement of the US$ 1100 million required for investment in new power generating capacity between now and the year 2000, a monumental task for Sri Lanka's policy makers, financiers and its state-owned utility. Given the difficulties of raising funds through conventional means, it is evident that a large proportion of the enormous investment in power, which will be crucial for Sri Lanka's drive for industrialization and its declared social objective of rural electrification by the year 2000, will have to financed through innovative mechanisms.

The means used to finance required investments in power generation will depend on the organization and ownership of the power sector in the near future. If the current pattern of state ownership and operation of the sector is continued, the government may be forced to obtain the required funds directly from international capital markets. Countries such as Mexico and Chile have raised infrastructure funds directly on the New York Stock Exchange, using instruments such as ADRs. Other sources of funds which can be utilized for this purpose, such as Global Power Investments and the Asian Infrastructure Fund, are described in Table 4.1.

Alternatively, Sri Lanka could turn to the private sector for infrastructure provision. Although it can attempt to emulate the systems in place in western industrialized countries such as the US or Britain, the Sri Lankan government is considering more strongly, schemes such as BOT and its variants, which have been introduced in rapidly growing countries in the Asian region. The eventual reversion of the assets to state control in these models for privatization make them more politically feasible.

The BOT method, a scheme used with considerable success in countries such as the Philippines and China, can be characterized as a non-recourse method of financing, because lenders look solely to the cash flows of the project to repay debt service, and have no recourse to other assets of the project participants if things go wrong. Therefore, it can used with success only in cases where the project is clearly capable of supporting the debt incurred. Most BOT projects are extremely difficult and uncertain undertakings, and the formalized risk relationships between government, lenders, investors, and contractors form the crux all such projects. These crucial ties should be addressed, arranged, documented, and regulated by the government who must design a workable formula that gives all involved parties the confidence that no single group is taking unreasonable risk or benefiting from unentitled reward. As a result of the complexity of the BOT scheme, many projects in Pakistan and even a few in Sri Lanka have failed at the negotiating stage. However, countries such as the Philippines, which have a careful and methodical planning process, have utilized the BOT model with considerable success.

The various forms of financial, political and technical risks I outlined in chapter 5 increase the return on equity demanded by potential investors in BOT schemes. The increase in the required ROE in turn raises the price at which the Sri

Lanka government purchases power from private developers—a cost which it subsequently passes on to domestic consumers. The whole economy of the country is then adversely affected, because electricity is a vital input in most forms of production, and rapid increases in its price will contribute to domestic inflation. This series of events may result in a harmful vicious cycle, because foreign developers in the power sector require their return in a major currency (usually dollars), and have to be paid more in terms of these inflated rupees, resulting in even higher levels of inflation. Therefore, it is vital that the government carefully examines the relationships among the discount rates, selling prices, and equity participation rates of the projects that are under consideration.

At the end of chapter 5, I examined the relationships among the above three factors using cashflow models of four projects—diesel 40 MW (10 year BOT), diesel 40 MW (15 year BOT), hydro 70 MW (15 year BOT) and coal 300 MW (15 year BOT)—and determined the viability of the projects from the investors' perspective under various combinations of the variables. The crucial figure associated with each viable project[1] is the "selling price" or the price at which the state would have to purchase the privately generated electricity, and this value should be compared with the long-term average price calculated by the CEB for its own 20-year generation plan: 2.89 Rs./kWh. At a discount rate of 15% (a reasonable rate for the projects under consideration), only the two diesel plants are viable at a selling prices of around 3.50-4.00 Rs./kWh. The hydro and coal plants are not viable at even 5.00 Rs./kWh.

Therefore, my analysis suggests that for private generation by the BOT method to be viable in Sri Lanka, the government should either be prepared to pay vastly increased prices for electricity (and pass on this cost to consumers by massive tariff increases), or take active measures to reduce the required ROE for projects in Sri Lanka. Since the former strategy alone is clearly infeasible, the state should actively pursue the latter. The required ROE for a project is directly tied to the

[1] A "viable" project was defined as one which had ROE>30% and DSCR>1.5

various risks associated with doing business in Sri Lanka, and in order to reduce it, the government should examine each of the financial, political, and technical risks, and take steps to mitigate it.

An extremely important first step is to bring peace and stability to the country. The current high levels of domestic government borrowing (to finance its defense expenditure) have pushed up interest rates. Since the ROE is usually set at 10 percentage points above the prime lending rate (as described in chapter 5), reducing interest rates will lower required ROEs. The government should also institute a comprehensive legal and regulatory framework, according to the guidelines described in chapter 6. This will result in increased investor confidence in the country, and hence reduce the required ROE for domestic projects. When determining the course of power sector privatization in Sri Lanka, policy makers should examine related experiences of nations in the region, and implement proven measures that are compatible with the economic, political and social realities in the country. I have briefly outlined the power situation (and private power generation) in some neighboring countries, in Appendix 4, to give the reader an idea of how other nations are dealing with problems similar to those faced by Sri Lanka.

As I stated at the outset, this thesis focuses mainly on how the government will finance required investment for additional generation capacity to meet projected demand growth rates of 8 percent per annum. In addition to using innovative financing schemes for this purpose, policy makers in the power sector should also implement measures which will reduce the demand growth rate without compromising economic growth. I have outlined some possible approaches it may consider are outlined in Appendix 5, to give the reader an idea of the larger framework within which BOT and other privatization schemes should be implemented.

The period from now till 2000 will be critical for the Sri Lankan economy. Since many other nations in the region are growing at a rapid pace, Sri Lanka faces the danger of falling behind in the race for attracting the crucial foreign investment required for further development. Proper infrastructure, especially a reliable and adequate supply of electricity, is an important requirement for making the country attractive to potential investors in other sectors of the economy. If the current civil war in the north and east of the nation stops in the near future, there will be a host of new growth opportunities, which will place additional strains on the nation's existing generating capacity. It is crucial therefore, that the country develops a flexible, realistic generation expansion plan which will meet future requirements, while securing the capital necessary to implement it.

# APPENDIX 1

## Accelerated Mahaweli Program–Reservoir Parameters[1]

| Parameter | Maduru Oya | Victoria | Kotmale Stage I | Kotamale Stage II | Randenigala | Rantambe |
|---|---|---|---|---|---|---|
| Type of Dam | Rockfill | Concrete Arch | Rockfill | Rockfill | Rockfill | Concrete |
| Max. Height. above bed | 43 m | 118 m | 87 m | 116 m | 94 m | 43.5 m |
| Length along Crest | 1,090 m | 555 m | 600 m | 600 m | 485 m | 410 m |
| Full supply Level above MSL | 96 m | 438 m | 703 m | 728 m | 232 m | 152 m |
| Crest Elevation | 101 m | 443 m | 706.5 m | 735 m | 238 m | 155 m |
| Gross Storage at FSL (Million cubic meters) | 596 | 730 | 174 | 408 | 860 | 21 |
| Spillway | Free Flow | Gates in Dam | Chute (now) | Orfice (later) | Gates on Side | Gates on Side |
| Tunnel Length | 5.7 km (link tunnel) | 5.6 km | 6.9 km | 6.9 km | 330 m- penstock | 20 m- penstock |
| Power House Type and Capacity | Below Sluices 3 of 8.5 MW | Concrete 3 of 70 MW | Underground 3 of 67 MW | Underground 3 of 67 MW | Below Dam 2 of 67 MW | Below Dam 2 of 26 MW |
| Funding Source | Canada | U.K | Sweden | ---- | Germany | Germany |
| Year of Completion | 1983 | 1985 | 1985 | ---- | 1986 | 1989 |

[1] Central Bank of Sri Lanka, Sri Lanka: An Economic, Financial and Investment Guide, p.65

# APPENDIX 2

**Independent Power Producers (IPPs) in Asia**[2]

| Country | Project | Sponsors | Project Size (MW) | Cost |
|---|---|---|---|---|
| Australia | Kwinana | • Mission, Black & Veatch | 110, thermal | Not available |
| | Smithfield | • Smithfield Energy Partners/Sithe | 167, thermal | Not available |
| China | Jingyuan II | • CEA (30%), State Development Bank (50%), Gansu Electric Power, Gansu Energy Construction Investment (10%) | 600 | US$ 400m |
| | Nanhai Electric | • Cheung Kong (30%), Nahai government (70%) | 600 | US$ 205m |
| | Rizhao Project | • China Power Investment Corporation, Shangdong Huaneng Power Devlopment, Shangdong International Trust & Investment Corporation, Rizhao Economic Development Corporation, Shangdong, Electric Power, United Development Inc. | 2x350, coal | US$ 650m |
| | Shanjio B Power Station | • CEPA Power China (BVI) (CEPA's interest 50%), Bank of China, Group Investment Kanematau Corp, Yue Xiu Enterprise (Holdings), Shum Yip Development | 2x350, coal | HK$ 4.1b |
| | Shanjio C Power Station | • CEPA Energy (BVI) (CEPA's interest 27%), Cachelot, Bank of China Group Investment Laito, Bank of China Group Insurance, Kanematsu Corp Nam Tung (Macao) Investment, Fortune Wheel Investment, The Ming An Insurance Co (HK), Stenus Nisso Iwai Hong Kong | 3x660, coal | US$ 1.9b |
| India | Ib Valley | • AES | 420 | US$ 632m |
| | Jegrupadu power project | • GVK, CMS, ABB | 235 | US$ 300m |
| | | | 208 | US$ 247m |
| | Kakinada | • Spectrum technologies, Bambino | coal | US$ 633m |
| | Orissa | • AES | | |

[2] Asia Money, "Power in Asia", p.40

| Country | Project | Sponsor | Project Size (MW) | Cost |
|---|---|---|---|---|
| Pakistan | Karachi Power | • Hyundai Heavy Industries, Sapphire, Karachi Electricity | 420 | US$ 500m |
| | PakGen | • AES | 337 | US$ 350m |
| | Uch | • Central Power, GE, Hasan, Hawkins Oil & Gas, Tenaska | 548 | US$ 600m |
| Philippines | Barge Plants | • CEPA's interest (100%) | 270, oil | not available |
| | Malaya ROMM project | • KEPCO 100% | 650, oil | US$ 250m |
| | Navatos I Power Station | • Hopewell Project Management (CEPA's interest 50.1%), Citicorp Vickers Power Facilitators Ltd., Citicorp Vickers Energy Investments Ltd, Asian Devlopment Bank, Commonwealth Development Corp, International Finance Corp | 3x70, oil | US$ 41m |
| | Navatos II Power Station | • Hopewell Tileman (Philippines) Corp (CEPA's interest 100%) | 100, oil | US$ 39m |
| | Pagbliao Power Station | • Hopewell Energy International (CEPA's interest 86.95%), Asian Development Bank, Commonwealth Development Corp, International Finance Corp | 2x367,coal | US$ 933m |
| | Quezon | • Ogden, Bechtel, PMR | 440 | US$ 725m |
| | Saul Power Station | • Panagasian Electric Corp (CEPA's interest 100%) | 2x600, coal | US$ 1.3b |

| Country | Project | Sponsor | Project Size (MW) | Cost |
|---|---|---|---|---|
| Indonesia | Bumpi Serpong Damai | • British Gas (56%), Bakerie (25%), AIG, PT Binatek Widiapratama (19%) | 200 | US$ 500m |
| | PT Cikarang Listrindo (P2) | • PT Cikarang Listrindo | 140 | not |
| | Corridor Block Gas | • Gulf Canada (54%), Talisman Energy (36%), Pertamina (10%) | gas | available |
| | Jawa Power (Paiton II) | • Siemens (50%), PowerGen (35%), PT Bumipertwi Tatapradipta (15%) | 1,120 | US$ 650m |
| | PT Paiton Energy | • Mission Energy BV (32.5%), PT Batu Hitam Perkasa (15%) | 1,230, coal | US$ 1.6b |
| | Sengkang power project | • Energy Equity | 135 | US$ 2.5b |
| | Tanjung Jati Power Station | • PT CEPA Indonesia, (CEPA's interest 100%) | 2x660 | US$ 240m |
| | | | | US$ 1.8b |
| Laos | Nam Theun II | • Transfield (10%), EdF (30%), Jasmine (10%), Submarine Telecom (25%), Ital-Thai Development (10%), Phatra Thanakit (15%) | 680 | US$ 1.1b |
| | Theun Hinboun | • Lao PDR (60%), MDX Power (20%), Nordic hydropower (20%) | 210 | US$ 270m |
| Malaysia | Bakun | • Ekran (51%), Tenaga, EPF, Hicom | 2,400 | US$ 4b |
| | Genting Sanyen Power | • Genting Sanyen Malaysia (40%), British Gas (20%), Tenaga (20%), Worldwide Holdings (20%) | 720, gas | US$ 700m |
| | Port Dickson Power | • Sime Darby (40%), Malaysian Resources (30%), Hypergantics (20%), Tenaga (10%) | 440, gas | not |
| | Powertek | • Cegas Unggul (35%), AMDB (30%), Malacca SEDC (20%), individuals (15%) | 440 | available |
| | Segari | • Segari Energy Ventures, Malaysian Resources Corp, Tenaga, Perak government | 1,300 | M$ 700m |
| | Sikap Energy Ventures | • Malakoff (75%), Tenaga (20%), Malaysian Resources (5%) | 1,303 | M$ 4b |
| | YTL Power Generation | • YTL (60%), Tenaga (20%), EPF (10%), Maybank (5%), John Liang (5%) | 1,212 | M$ 4b |
| | | | | M$ 3.4b |

# APPENDIX 3

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## Ingredients of Good Performance Under Alternative Institutional Forms

Public Ownership and Public Operation[1]

- Government roles as owner, regulator, an d operator clearly separated.
- No government interference in detailed management.
- Public enterprises subject to general commercial law and to general accounting and auditing standards (operating on "level playing field" with private enterprises).
- Tariffs set to achieve cost recovery as appropriate, and enterprise subject to hard budget.
- Public service operations, if any, targeted and compensated explicitly by government transfers.
- Managers selected by professional qualifications and compensated appropriately.
- Appropriate mechanisms in place to obtain feedback from users.
- Discrete activities and functions that can be unbundled open to private entry (for example through service contracts).
- Private management skills obtained as needed entry (for example through management contracts).
- Ownership and control shared with the private sector (for example, as minority shareholder).

**Public Ownership and Private Operation**

- Basic legal framework of contract law, including credible enforcement mechanisms in place.

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[1] World Bank, World Development Report 1994: Infrastructure for Development, p.111

- Contracts clearly specify monitorable performance targets, responsibilities of owner and operator, processes for periodic review (especially to account for unforeseen changes in input costs), mechanisms to resolve disputes and sanctions for non performance.
- Contracts awarded by transport selection process, preferably competitive bidding.

Private Ownership and Private Operation

- Appropriate competitive restructuring of subsector undertaken
- Practical and statutory barriers to private entry removed (for example, restrictions on access to credit and foreign exchange).
- Regulation in place to protect public interest when competitive discipline is insufficient and to ensure private entrants access to network facilities when relevant

Community and User Provision

- Participation of users or community members from earliest stage of program preparation to ensure willingness to pay and ownership of scheme.
- Participation of beneficiaries ensured through appropriate organizational means, and with contributions in kind or in cash.
- User group supported by access to training and technical assistance from sectoral agency or non-governmental organizations.
- Appropriate consideration given to technical requirements for interconnection with primary or secondary network infrastructure, if relevant.
- Service operators appropriately trained, compensated, and held accountable.

# APPENDIX 4

## Case Studies from Other Developing Nations

The exceptionally rapid pace of growth in the Asian region has resulted in a surge of infrastructure building among nations in the area[2]. In early 1994, the Asian Development Bank estimated that the region would spend $1 trillion by the year 2000, primarily on energy, telecommunications, and transportation. However, this estimate is viewed as conservative by Hong Kong's Peregrine group which estimates that China, South Korea, Taiwan, Hong Kong, and the five biggest nations in Southeast Asia will require US$ 1.9 trillion for this purpose. These Asian nations see infrastructure as a key requirement to their continued growth as their cheap-labor advantage begins to diminish as they move toward fully industrialized status.

Reliable electric power is necessary for economic development in the Third World as it has been for developed countries[3]. Despite major changes since the Arab oil embargo in the late 1970s, the overall relationship between energy growth and GDP growth in industrial countries has been close to one-to-one.

Electricity use in the commercial and residential sectors of many nations is rising sharply, and in some countries has even outstripped industrial sector consumption. Furthermore, many of these countries have adopted aggressive plans for rural electrification in an effort to decentralize their populations and to distribute the benefits of economic growth. Therefore, the requirements for electric power in the region are huge, and have been estimated at around 225 GW before the year 2000.

As a result of the inability of many Asian governments to invest adequately in their power sectors, the demand for electric services has risen more rapidly than supply,

[2] Business Week, "Building the New Asia", November 28, 1994
[3] USAID, Power Shortages in Developing Countries...., p.v

and many countries now face critical power shortages of over 10 percent of their generation capability. These power shortages and unmet demands for power present significant economic problems. In Pakistan, for example, USAID estimated that load shedding in the industrial sector alone has led to a 1.8 percent decrease in GDP and a 4.2 percent decrease in the country's foreign exchange earnings[4]. In India, the current 10 percent average supply cut to the industrial sector is estimated to cause an annual production loss of over US$ 6 billion—equivalent to 12 percent of the country's industrial output[5]. Consequently providing the required power for development has become a major concern among Asian governments, who have adopted various strategies for meeting this challenge.

In this appendix I will examine the electric power situation in some Asian countries and explore the various steps they have taken to meet future demand. The nations I will look at are India, Indonesia, Malaysia, Philippines, Thailand and Vietnam. Although these nations have had various degrees of success in meeting their goals of electricity provision, and in some instances are faced with unique national circumstances, their experiences still provide valuable insights to planners in the Sri Lankan power sector.

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[4] USAID, Power Shortages in Developing Countries...., p.v
[5] USAID, Power Shortages in Developing Countries...., p.v

## China

Basic Facts[6]

| | |
|---|---|
| Land Area | 3,696,100 sq mi (9,561,000 sq km) |
| Population | 1,203,097,268 |
| GDP (Purchasing Power Parity Terms) | US$ 2.6 trillion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 2,200 |
| National Budget (1994 estimate) | US$ 61.4 billion |
| Currency | Yuan/Renminbi (Y/Rmb) |
| Exchange rate (May 1995) | Rmb 8.3: US$ 1 |
| Change in CPI (inflation) | 17% |
| Electricity | 740 billion kWh |

The Power-Sector, and Privatization Efforts

In spite of China's rapid economic growth, which requires a substantial amount of new power capacity, many project development teams are having problems with the country's slow bureaucratic process. Estimates for the amount of new capacity needed in China by the year 2000 range from between 80,000 MW to 137,000 MW[7]. Even taking the conservative estimate, this translates into 16,000 MW of new power plants each year. These figures will be daunting even for a country with flexible and inviting foreign investment laws, but in China, where the investment process is hampered by excessive regulation and bureaucracy, the goal seems more difficult to attain.

China's provincial governments have been given freedom to approve power projects that cost less than US$ 30 million[8]. Although these projects are small in size, many foreign companies seem eager to get regulatory approval to build them. A strategy some have pursued is to apply for several of these small plants. Once permission is granted, the company can group the projects under one holding company, and then get financial backing from the debt and equity markets. Structuring one medium-sized financing is easier than doing so for several small deals, and the regulatory process is accelerated by circumventing the cumbersome procedure of

[6] World Almanac and Book of Facts 1995, Funk and Wagnells Corporation (New Jersey, USA: 1995), and Economist Intelligence Unit, Country Profile 1995-96: China, Electronic Publishing Services (London, United Kingdom: 1995).
[7] Asia Money, "Power in Asia", December 1995/January 1996, p.53
[8] Asia Money, "Power in Asia", December 1995/January 1996, p.54

dealing with Beijing. The companies can thus continue to increase their generating capacity, and hence the total power output each manages, so long as each new plant is worth less than the US$ 30 million.

An example of this investment strategy is the financing of the Hui Lo power plant in Luoding City, Guangdong Province. A six-year loan was signed in October 1995 by Finenco China Investment for US$ 20.5 million with a consortium of five Italian banks, led by Banca Commerciale Italiana[9]. Another similar example is the Pan Jin Liao He Thermal Power Company, which received debt financing to construct and develop a power plant, located in Panjin City, Liaoning Province. The US$ 20 million loan was arranged by CCIC Finance, with four other banks participating. Although this strategy of building small power plants leaves many investment opportunities in China's power sector untapped, some investors see it as a way around the bureaucratic nightmares of dealing with the Beijing authorities.

Independent Power Producers—China[10]

*Jingyuan II – 600 MW*

| | |
|---|---|
| Status | In Progress |
| Cost | US$ 400 million |
| Sponsors | CEA (30%), State Development Bank (50%), Gansu Electric Power, Gansu Energy Construction Investment (10%) |
| Financing | US$ 100 million equity |

*Nanhai Electric – 600 MW*

| | |
|---|---|
| Status | In progress |
| Cost | US$ 205 million |
| Sponsors | Cheung Kong (30%), Nahai government (70%) |
| Financing | US$ 90 million seven-year loan with Gitic guarantee; US$ 40 million four year loan guarantee by Nanhai Itic |

[9] Asia Money, "Power in Asia", December 1995/January 1996, p.54
[10] Asia Money, "Power in Asia", December 1995/January 1996, pp.40-41

*Rizhao Project – 2x350 MW, coal-fired plant*

| | |
|---|---|
| Status | 1999 |
| Cost | US$ 650 million |
| Sponsors | China Power Investment Corporation, Shangdong Huaneng Power Development, Shangdong International Trust & Investment Corporation, Rizhao Economic Development Corporation, Shangdong, Electric Power, United Development Inc. |
| Financing | Equity US$ 150 million, domestic loans US$ 150 million, export/commercial loans US$ 350 million |

*Shanjio B Power Station – 2x350 MW, coal-fired plant*

| | |
|---|---|
| Status | 1997 contract completion |
| Cost | HK$ 4.1 billion |
| Sponsors | CEPA Power China (BVI) (CEPA's interest 50%), Bank of China, Group Investment Kanematau Corp, Yue Xiu Enterprise (Holdings), Shum Yip Development |
| Financing | Equity 20%; syndicated loans 80% |

*Shanjio C Power Station – 3x660 MW, coal-fired plant*

| | |
|---|---|
| Status | 1996 contract completion |
| Cost | US$ 1.9 billion |
| Sponsors | CEPA Energy (BVI) (CEPA's interest 27%), Cachelot, Bank of China Group Investment Laito, Bank of China Group Insurance, Kanematsu Corp Nam Tung (Macao) Investment, Fortune Wheel Investment, The Ming An Insurance Co (HK), Stenus Nisso Iwai Hong Kong |
| Financing | Syndicated loans 49%; early completion and shareholders' loans 51% |

**India**

Basic Facts[11]

| | |
|---|---|
| Land Area | 1,222,243 sq mi (9,561,000 sq km) |
| Population | 936,545,814 |
| GDP (Purchasing Power Parity Terms) | US$ 1.7 trillion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 1,300 |
| National Budget (1994 estimate) | US$ 45.1 billion |
| Currency | Rupees (Rs.) |
| Exchange rate (May 1995) | Rs. 31.42: US$ 1 |
| Change in CPI (inflation) | 10.2 % |
| Electricity | 324 billion kWh |

The Power-Sector, and Privatization Efforts

Power demand in India is growing rapidly with industrial development but the (overwhelmingly) public sector generators are unable to meet it[12]. The total installed electricity capacity in public utilities at the end of 1993/94 was 76,713 MW, following an increment of 4,450 MW that year. Of the total, 22% was hydroelectric, 2% nuclear and 76% thermal[13]. There was also 10,200 MW capacity in non-utilities like the Tata station, which supplies Bombay. Generation and transmission are inefficient, with an average 57% plant load factor in 1993/94 in thermal plants (although this is an enormous improvement on the 44% in 1980/81). Power actually generated by utilities in 1993/94 was 324 billion kWh (356 billion kWh overall)[14]. The shortage of power at peak times is close to 20% and is significantly worse in some states which have extensive "brown outs".

| | Installed Capacity (MW) | Gross generated capacity (m kWh) |
|---|---|---|
| Hydro | 20.4 | 70.4 |
| Thermal | 54.3 | 247.8 |
| Nuclear | 2.0 | 5.4 |
| Non-utilities | 10.2 | 32.1 |
| **Total** | **86.9** | **355.6** |

[11] World Almanac and Book of Facts 1995, and EIU Country Profile 1995-96: India
[12] EIU Country Profile 1995-96: India, p.29
[13] EIU Country Profile 1995-96: India, p.29
[14] EIU Country Profile 1995-96: India, p.29

As India develops further, with domestic use of appliances growing and power supplies extending to rural areas, demand will continue to grow rapidly, probably more than the 8% per year of the last two decades. An official long-term forecast states that 465 billion kWh will be needed annually by the year 2000. These investment requirements are far beyond the capacity of the public sector. Although, 5,000-7,000 MW of new capacity annually is needed, recent installation is below that level (averaging 4,000 MW per year in the 1990s so far.)

In 1991 the government decided to welcome private companies into power generation. It promised a minimum 16% rate of return (with a foreign exchange guarantee) and various incentives to raise profits if the plant load factor rises above 68.5%. To provide comfort against non-payment by state electricity boards, the central government has offered a counter guarantee to the most advanced projects (eight, with a combined capacity of 5,000 MW). Some 140 proposals have been made including more than 40 from foreign investors.

The above government effort suffered a setback in 1995, when the Maharashtra state government put a freeze on a US$ 2.8 billion concession to build a 2,015 MW project led by Enron Corp[15]. This happened even though most of the US$ 150 million offshore commercial loan component of the US$ 1.2 billion financing has already been drawn down. The reasons cited for the state government's action included capital costs, payment terms, environmental protection. Its main assertion was that the cost of electricity would be too high-- Enron was to receive 2.40 rupees or seven US cents per kWh from the Maharashtra State Electricity Board. In November 1995, however, Enron reached a compromise with the Maharashtra government which included a reduction in the tariff price to reportedly six US cents. The project has been resumed, but the delay has been extremely costly-- US$ 250,000 a day, according to Enron.

While Enron may have saved its Maharashtra project, the north-western Indian state of Rajasthan has rejected its offer to set up a 2,400 MW solar power plant and sell

[15] Asia Money, "Power in Asia", December 1995/January 1996, p.35

electricity at Rs. 5.12 per unit for 25 years[16]. Instead, it accepted the offer of Energen International, a consortium of German and Sri Lankan companies, to provide energy at Rs. 2.61 per unit for seven years. The electricity will be generated from a 200 MW solar plant to be set up in Jaisalmer at an estimated cost of US$ 200 million. This project will carry no state guarantees.

The Rajasthan government also signed a letter of intent with British Power Industries to develop 10 naphtha-based power plants of 40 MW each. The company secured the contract with an offer to sell electricity at Rs. 2.10 a unit. It was the lowest bid of the 66 companies that submitted proposals.

Independent Power Producers—India[17] (Asia Money 40-41)

*Ib Valle – 420 MW*

| | |
|---|---|
| Status | Financing in Progress |
| Cost | US$ 632 million |
| Sponsors | AES |
| Financing | US$ 100 million local bank loan; US$ 240 million offshore loan, backed by US-Exim; US$ 75 million OPIC loan; US$ 20 million each from IFC and ADB |

*Jegrupadu power project – 235 MW*

| | |
|---|---|
| Status | Financing in Progress |
| Cost | US$ 300 million |
| Sponsors | GVK, CMS, ABB |
| Financing | Bank loan, equity; IFC: US$ 8 million equity, US$ 40 million A loan, US$ 70 million B loan, in syndication |

[16] Asia Money, "Power in Asia", December 1995/January 1996, p.69
[17] Asia Money, "Power in Asia", December 1995/January 1996, p.40-41

*Kakinada – 208 MW*

| | |
|---|---|
| Status | In progress; PPA review |
| Cost | US$ 247 million |
| Sponsors | Spectrum technologies, Bambino |
| Financing | US$ 79 million ECGD buyer credit; IDBI-arranged local debt |

*Orissa – coal-fired plant*

| | |
|---|---|
| Cost | US$ 633 million |
| Sponsors | AES |
| Financing | Equity 28%; Debt 72%: ADB, IFC, OPIC, US-Exim |

## Indonesia

Basic Facts[18]

| | |
|---|---|
| Land Area | 741,052 sq mi (9,561,000 sq km) |
| Population | 203,583,886 |
| GDP (Purchasing Power Parity Terms) | US$ 571 billion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 2,900 |
| National Budget (1994 estimate) | US$ 32.8 billion |
| Currency | Rupiah (Rp) |
| Exchange rate (May 1995) | Rp 2,236: US$ 1 |
| Change in CPI (inflation) | 8.5 % |
| Electricity | 45.8 billion kWh |

### The Power Generation Sector

The absence of adequate power generation and distribution capacity has long been recognized as an important constraint to Indonesia's overall development; thus, the government has made considerable efforts to address this problem since the early 1970s. The state-owned electricity company Perusahaan Umum Listrik Negara (PLN) is an integrated corporation responsible for generating, transmitting, and distributing electricity throughout the country. It has undertaken large investments, involving substantial financial assistance from the World Bank and the Asian Development Bank (ADB), and raised its generating capacity from 776 MW in 1973 to an estimated 13,569 MW in fiscal year 1993/94[19].

Aware of the growing threat of a depletion of its exploitable oil reserves in the coming years, the Indonesian government has sought to diversify the structure of the power-generating industry and to increase the share of its capacity based on non-oil energy sources. It has emphasized the establishment of gas and coal-based power plants and taken steps to develop Indonesia's hydropower and geothermal energy resources. In addition, the government has also announced a plan to establish a nuclear power-generating capacity in the foreseeable future.

[18] World Almanac and Book of Facts 1995, and EIU Country Profile 1995-96: Indonesia

[19] EIU Country Profile 1995-96: Indonesia, p.37

Distribution of energy production by source[20]

| | GWh (1987/88) | % (1987/88) | GWh (1992/93) | % (1992/93) |
|---|---|---|---|---|
| Oil | 11,169 | 51.8 | 19,515 | 47.7 |
| Coal | 4,920 | 22.8 | 10,438 | 25.5 |
| Hydropower | 4,457 | 20.7 | 8,788 | 21.5 |
| Geothermal | 719 | 3.3 | 1,084 | 2.7 |
| Natural Gas | 293 | 1.4 | 1,075 | 2.6 |
| **Total** | **21,559** | **100.0** | **40,900** | **100.0** |

Coal-based generation

Indonesia's first major coal-fired generating facility, the Suralaya power station in West Java, became operational in 1985. The plant has since been expanded to four units of 400 MW each, with a further three units with a total capacity of 1,800 MW currently under construction and due to be completed between February 1997 and February 1998. Additional coal-fired generating capacity is also being established at the Paiton complex at Probolinggo in East Java which is due to come on steam in 1999. A number of smaller projects for coal-based power generation are also in progress near Bukit Asam and Ombilin coal mines in South Sumatra and West Sumatra respectively, while negotiations are currently in progress for the establishment of another large-scale privately operated plant at Tanjung Jati near the town of Jepara in Central Java.

Gas-fired plants

From 42,000 kW in 1973, Indonesia's gas-fired power generating capacity increased to 1,243 MW in fiscal year 1993/94, in addition to which an additional capacity of 1,817 MW of combined-cycle gas and coal fired capacity has been established since 1991[21]. The most important of these gas-fired and combined-cycle plants are located in the industrial town of Gresik and at the Paiton power station in East Java, and at the Muara Karang and Tanjung Priok power stations in Jakarta. Other large-scale combined-cycle plants are being built, or planned, at Muara Tawar in West

[20] EIU Country Profile 1995-96: Indonesia, p.38
[21] EIU Country Profile 1995-96: Indonesia, p.38

Java, Tambak Lorak in Central Java, Grati/Pasuruan in East Java, and the port city of Belawan in North Sumatra.

Hydroelectric potential

Indonesia's potential exploitable capacity of hydroelectric power is estimated at more than 75,600 MW per year, of which nearly a third is located in Irian Jaya. To date, less than 3% of this potential capacity has been tapped, with total installed hydropower capacity amounting to less than 2,200 MW in fiscal year 1993/94[22]. A number of large hydroelectric plants are under construction in Sumatra.

Geothermal potential

Because of its volcanic geology, Indonesia has large geothermal reserves, and 217 sites have so far been identified throughout Indonesia with a total potential capacity of about 16,000 MW of geothermal power. A significant further expansion of geothermal power generating capacity is planned for the coming years, mainly by private investors.

Nuclear potential

Indonesia does not possess a commercial nuclear power generating capacity, but research into the feasibility of installing such a capacity is in progress. The National Atomic Energy Board (Badan Tenaga Atom Nasional, BATAN), has been granted the exclusive right to explore and develop Indonesia's uranium resources. A major technical research center has also been set up by BATAN at Serpong near Jakarta, where a 30-MW research reactor and a plant for the production of fuel elements were inaugurated in August 1987. A proposal to build a commercial nuclear power station with a capacity of 600-1,000 MW at Mount Muria in Central Java is under consideration, with construction expected to commence in 1996 despite strong public opposition within Indonesia and abroad.

[22] EIU Country Profile 1995-96: Indonesia, p.38

## Private Participation

The role of private participation in generation is expected to increase dramatically following the introduction of new government policies since September 1990 to encourage private investment under a variety of BOO and BOT arrangements. This government action has resulted in a surge of investment interest from a number of domestic business groups, several of which have entered into joint ventures with foreign firms to establish plants by the end of the current decade or in the opening years of the next.

## Independent Power Projects – Indonesia[23] (Asia Money 40-41)

*Bumpi Serpong Damai – 200 MW*

| | |
|---|---|
| Status | Financing in Progress |
| Cost | US$ 500 million |
| Sponsors | British Gas (56%), Bakerie (25%), AIG, PT Binatek Widiapratama (19%) |
| Financing | Bank Loans; US-Exim Loan |

*PT Cikarang Listrindo (P2) – 140 MW*

| | |
|---|---|
| Status | 1996 |
| Cost | Not Available |
| Sponsors | PT Cikarang Listrindo |
| Financing | Indonesian Bank Loans; US-Exim |

*Corridor Block Gas – gas plant*

| | |
|---|---|
| Status | In Progress |
| Cost | US$ 650 million |
| Sponsors | Gulf Canada (54%), Talisman Energy (36%), Pertamina (10%) |
| Financing | Equity; US$ 450 million debt |

*Jawa Power (Paiton II) – 1,120 MW*

| | |
|---|---|
| Status | PPA signed; Financing in progress |
| Cost | US$ 1.6 billion |
| Sponsors | Siemens (50%), PowerGen (35%), PT Bumipertwi Tatapradipta (15%) |
| Financing | Equity; US-Exim and Hermes cover; commercial loans |

[23] Asia Money, "Power in Asia", December 1995/January 1996, p.40-41

*PT Paiton Energy – 1,230 MW, coal plant*

| | |
|---|---|
| Status | 1999 |
| Cost | US$ 2.5 billion |
| Sponsors | Mission Energy BV (32.5%), PT Batu Hitam Perkasa (15%) |
| Financing | Equity 27%; JEXIM, US-Exim, OPIC, international banks with MITI, commercial banks |

*Sengkang power proje – 135 MW*

| | |
|---|---|
| Status | Negotiating PPA |
| Cost | US$ 240m |
| Sponsors | Energy Equity |
| Financing | Equity, loan, export credits |

*Tanjung Jati Power Station- 2x660 MW*

| | |
|---|---|
| Status | 1999 contract completion |
| Cost | US$ 1.8 billion |
| Sponsors | PT CEPA Indonesia, (CEPA's interest 100%) |
| Financing | Exim credit 73%; multilateral agencies 21%; bank loans 6% |

## Malaysia

Basic Facts[24]

| | |
|---|---|
| Land Area | 127,584 sq mi (9,561,000 sq km) |
| Population | 19,723,587 |
| GDP (Purchasing Power Parity Terms) | US$ 141 billion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 7,500 |
| National Budget (1994 estimate) | US$ 18.0 billion |
| Currency | Malaysian dollar or Ringgit (M$ or RM) |
| Exchange rate (May 1995) | M$ 2.47: US$ 1 |
| Change in CPI (inflation) | 3.7 % |
| Electricity | 30.6 billion kWh |

The Electricity Sector

The average annual growth in electricity demand for Peninsula Malaysia for the past decade was 8.7 percent and since 1988, the growth rate has been greater than 12 percent. Electricity demand growth has consistently outpaced GDP growth and this trend is expected to continue in the future[25].

The Ministry of Energy, Telecommunications, and Posts is responsible for many of the operational functions of the electric power sector[26]. The three utilities in Malaysia, Tenaga Nasional Berhad (TNB), Sabah Electricity Board (SEB), and Sarawak Electricity Supply Corporation (SESCO), handle power planning within their respective regions.

Electricity Production[27]

| | 1988 | 1989 | 1990 | 1991 |
|---|---|---|---|---|
| Hydro (MW) | 1,427 | 1,421 | 1,431 | 1,431 |
| Diesel (MW) | 574 | 557 | 495 | 444 |
| Gas Turbine (MW) | 381 | 384 | 384 | 486 |
| Steam (MW) | 2,230 | 2,530 | 2,490 | 2,490 |
| Combine Cycle (MW) | 870 | 870 | 870 | 870 |
| **Total** | 5,482 | 5,762 | 5,670 | 5,721 |

[24] World Almanac and Book of Facts 1995, and EIU Country Profile 1995-96: Malaysia
[25] Muthiah, Shanthi, Privatization and Restructuring of the Electric Power Sector in Malaysia: Implications of Pricing Policy (Massachusetts Institute of Technology, Cambridge: September 1995), p.45
[26] Muthiah, Shanthi, Privatization and Restructuring..., p.37
[27] Muthiah, Shanthi, Privatization and Restructuring..., p.47

Privatization

In 1987, the government commissioned a study which examined the possibility of privatization of NEB in detail[28]. After much debate about the most efficient and appropriate utility structure, and whether it should be fragmented by function or by region, it was decided that the National Electricity Board would be privatized in total. The objectives of privatization were determined to be as follows:

- To raise efficiency and productivity by making managers accountable for performance; this was to be accomplished through employee incentives and the freeing of the enterprise from political supervision and civil service rigidities
- To promote competition
- To relieve the financial and administrative burden of the government to leave the government free to concentrate on maintaining law and order and ensuring economic growth with equitable distribution
- To reduce the size and presence of the public sector
- To broaden the base of ownership and participation from the public, specifically while meeting the targets of government plans
- To facilitate economic growth

The first step in the privatization process was taken by incorporating the NEB into Tenaga Nasional Berhad in 1990. This involved the passage of enabling legislation, a close examination and resolution of a large number of legal matters, including issues of land tenure and rights-of-way that had to be transferred from the public to the private domain, and provisions for the change of status of about 25,000 government employees. Additionally, the regulatory framework was drastically altered, primarily with the introduction of the Electricity Supply Act through which the Department of Electricity Supply (DES) was created. All legal and regulatory provisions were transferred to this department. Within this context, DES is responsible for ensuring adequate electricity supply and quality for current and future needs, as well as reasonable pricing and protection for customers. While DES was established through an

[28] Muthiah, Shanthi, Privatization and Restructuring..., p.47

act of parliament and is legally independent of the Ministry of Energy, Telecommunications and Posts, there is considerable consultation and coordination between the two departments.

Independent Power Producer Program

The IPP Program was born out of three primary needs—to alleviate the power shortage problems, to induce competition, and to lessen the financial burden on the government. The privatization of TNB had served as the initial step to prepare for competition, and in 1992, the government (EPU) announced its interest in introducing competition vis à vis the Independent Power Program. Thereafter, the private sector provided unsolicited proposals, consistent with the guidelines of the Privatization Masterplan. There has been a very loose framework for processing and accepting of these proposals and to date, no concrete framework or set guidelines has been issued.

The entire process of IPP negotiations and approval has been very politically sensitive. Two of the consortiums were explicitly invited by the government, while in the others, the composition of shareholders and investors were influenced by political connections and implicit government policy. The terms negotiated were very favorable to the IPPs, who were faced with fairly low risks and were awarded high purchase prices.

Despite the numerous applications received, only five IPPs were granted licenses in the 1992-1993 period for a total generating capacity of 4500 MW. The plants are expected to come on line by 1997 at which time the reserve margin capacity may reach 50 percent[29]. However, this margin will most likely reduce to the targeted 30 percent by 1999 or the year 2000 as a result of the rapid growth in demand.

Most of the IPPs use natural gas from small fields or associated oilfield gas (which would otherwise be flared wastefully) in combined-cycle gas-turbine generators. These provide cheap and reliable power with little net impact on the environment. The World Bank has recommended maximum exploitation of this resource before Malaysia

[29] Muthiah, Shanthi, Privatization and Restructuring..., p.49

builds any more large hydroelectric stations. Nevertheless, the government is proceeding with two very large hydroelectric schemes which involve the displacement of aboriginal families as well as the clearing and flooding of large areas of virgin rainforest. These actions have been the subject of particular controversy.

One of these schemes, on the River Pergau in the north-east peninsular state of Kelantan, is being built by British contractors who were awarded the tender for the work because the UK government offered a heavily-subsidized loan out of aid funds to finance it. The offer had originally been improperly linked to the sale of British military aircraft and weaponry. In turn net economic benefit of the finished scheme to Malaysians has been questioned. This complication prompted a UK court ruling that the use of aid funds on the project was unlawful, and the UK government has had to pay for the subsidy out of general funds.

The second of the large hydroelectric schemes, the 2,400 MW Bakun dam project in Sarawak, is more ambitious and technically much more difficult. It requires the flooding of an area of virgin forest larger than Singapore island. Power demand in Sarawak and the adjacent area will be quite insufficient to absorb the output, and it is proposed that power will be transmitted to Peninsular Malaysia via a 1,200 km cable, 650 km of which will run under the sea[30]. States operate environmental controls over such development sites in Malaysia, and development permission was granted last year, allowing the local company responsible for the project to fell valuable timber. There has been much criticism, within Malaysia as well as abroad, because the technical feasibility study for the transmission line had yet to be completed, and Sarawak does not provide for full public examination of the environmental impact assessment (EIA) on which its approval of the development was based.

[30] EIU Country Profile 1995-96: Malaysia, p.29

## Independent Power Projects – Malaysia[31]

*Bakun – 2,400 MW*

| | |
|---|---|
| Cost | US$ 4 billion |
| Sponsors | Ekran (51%), Tenaga, EPF, Hicom |
| Financing | 65:35 debt to equity expected, mostly by local banks |

*Genting Sanyen Power – 720 MW, gas-fired plant*

| | |
|---|---|
| Status | 1996 |
| Cost | US$ 700 million |
| Sponsors | Genting Sanyen Malaysia (40%), British Gas (20%), Tenaga (20%), Worldwide Holdings (20%) |
| Financing | Equity 25%; Maybank Bhd 75% (non recourse) |

*Port Dickson Power – 440 MW, gas & distillate*

| | |
|---|---|
| Status | 1996 |
| Cost | Not available |
| Sponsors | Sime Darby (40%), Malaysian Resources (30%), Hypergantics (20%), Tenaga (10%) |
| Financing | Malaysian Bank loans, Malaysia EPF bonds |

*Powertek – 440 MW*

| | |
|---|---|
| Status | In commission 1995 |
| Cost | M$ 700 million |
| Sponsors | Cegas Unggul (35%), AMDB (30%), Malacca SEDC (20%), individuals (15%) |

*Segari – 1,300 MW*

| | |
|---|---|
| Cost | M$ 4 billion |
| Sponsors | Segari Energy Ventures, Malaysian Resources Corp, Tenaga, Perak government |

*Sikap Energy Ventures – 1,303 MW*

| | |
|---|---|
| Cost | M$ 4 billion |
| Sponsors | Malakoff (75%), Tenaga (20%), Malaysian Resources (5%) |

*YTL Power Generation – 1,212 MW*

| | |
|---|---|
| Status | In commission 1997 |
| Cost | M$ 3.4 billion |
| Sponsors | YTL (60%), Tenaga (20%), EPF (10%), Maybank (5%), John Liang (5%) |

[31] Asia Money, "Power in Asia", December 1995/January 1996, p. 40-41

**Philippines**

Basic Facts[32]

| | |
|---|---|
| Land Area | 115,860 sq mi (9,561,000 sq km) |
| Population | 73,265,584 |
| GDP (Purchasing Power Parity Terms) | US$ 171 billion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 2,500 |
| National Budget (1994 estimate) | US$ 13.0 billion |
| Currency | Peso (P) |
| Exchange rate (May 1995) | P 26.02: US$ 1 |
| Change in CPI (inflation) | 9.1 % |
| Electricity | 28 billion kWh |

The Power-Sector

The power generating capacity of the Philippines was 6,927 MW at the end of 1993, of which 2,244 MW was from hydroelectric, 3,095 MW was from oil-fired and 550 MW was from coal-fired plants. Geothermal capacity was 1,038 MW[33]. There was no major increase in capacity in the mid-1980s, and this, combined with the effect of drought and the destruction of watershed areas in Mindanao produced a serious shortage of power in 1991-93. In May 1992 the deficit on the Luzon grid had reached 1,000 MW. Around 620 MW of this was supposed to have been covered by the country's nuclear power plant, Bataan, which was due to begin operation in 1986. The Aquino government halted the project, largely for safety reasons, because the project-site is located near a seismic fault line. The already severe power shortage was intensified because the installation of coal-fired and combined plants also failed to materialize.

The Ramos government launched a fast-track program of electricity expansion to eliminate the electricity shortage by the end of the 1993. Improved weather conditions and additions to thermal capacity had reduced the deficiency in Minandao to about 10% by the final quarter of 1993, and daily power cuts in Luzon had ceased by November. By the end of 1994 power-generating capacity was about 9,000 MW. A substantial contribution to the increase came from plants built under BOO agreements, and this method of financing will grow in importance in order to meet the targets of the state

[32] World Almanac and Book of Facts 1995, and EIU Country Profile 1995-96: Philippines
[33] EIU Country Profile 1995-96: Philippines, p.27

utility's power development program. An additional power capacity of 30,000 MW is expected to be added by the year 2010, with coal-fired plant increasing its share of the total to 63% and gas's share (supplied from the offshore fields), increasing to 10%[34].

However, the greatest potential for expansion in Philippines' power generation capacity, in the long term, lies in geothermal energy. Geothermal power generation on a commercial scale began in 1979 and the level of production is now second in the world only to that of the USA. Further expansion of generation is expected to arise out of the major geothermal development program currently in progress.

Electricity Production (in kWh)[35]

| | 1988 | 1989 | 1990 | 1991 | 1992 |
|---|---|---|---|---|---|
| Oil-fired | 9,542 | 9,788 | 10,699 | 10,598 | 10,936 |
| Hydro | 6,212 | 6,473 | 6,051 | 5,097 | 4,236 |
| Geothermal | 4,842 | 5,316 | 5,463 | 5,760 | 5,700 |
| Coal-fired | 2,344 | 2,223 | 1,716 | 1,942 | 1,977 |
| Gas turbine | 0.0 | 287 | 851 | 2,023 | 2,701 |
| **Total** | **22,940** | **24,087** | **24,780** | **25,420** | **25,550** |

Privatization Schemes

The Philippines is aggressively promoting BOT schemes to finance the infrastructure the country needs so urgently[36] (Asian Business 04/94, 6). The government has amended its laws to allow variations such as BOO and BTO, and a new government fund, Philippine Strategic Holdings, will be started in order to raise money for BOT projects from private sources. BOT has been managed under the country's foreign aid umbrella, the Coordinating Council of the Philippines Assistance Program, through which the government now allows foreign aid money to be used as loans in BOT projects to cover as much as 25% of the bid price.

The country started its first BOT schemes in 1992 to develop fast-track power projects in an effort to stop its crippling power failures. Enron Power Corp of the US,

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[34] EIU Country Profile 1995-96: Philippines, p.27

[35] EIU Country Profile 1995-96: Philippines, p.27

[36] Asian Business, "Philippines: Open Arms for Investors", April 1994, p.6

Switzerland's Asea Brown Boveri and Japan's Kawasaki and Marubeni were some of the first companies to participate in BOT schemes.

One showcase for the BOT policy is a coal-fired power plant being built by Hopewell Energy International of Hong Kong. The US$ 933 million, 700 MW station at Pagbilao in Quezon province was the first project to be tendered internationally. The plant, which was started in March 1993, is 10 months ahead of schedule, and is expected to be operating by early 1996. Hopewell has also won a US$ 2 billion contract to build the country's biggest power project, a 1,000 MW coal-fired power plant in Saul, Pangasinan in the northern Philippines[37].

Independent Power Projects – Philippines[38] (Asia Money 40-41)

*Barge Plants – 270 MW, oil-fired plants*

| | |
|---|---|
| Status | 1993 |
| Cost | Not available |
| Sponsors | CEPA's interest (100%) |
| Financing | Equity 100% |

*Malaya ROMM project – 650 MW, oil-fired plant*

| | |
|---|---|
| Status | 1998 after rehabilitation |
| Cost | US$ 250 million |
| Sponsors | KEPCO 100% |
| Financing | Equity 13%; KEPCO support, Korea Development Bank |

*Navatos I Power Station – 3x70 MW, oil-fired plant*

| | |
|---|---|
| Status | 1991 contract completion |
| Cost | US$ 41 million |
| Sponsors | Hopewell Project Management (CEPA's interest 50.1%), Citicorp Vickers Power Facilitators Ltd., Citicorp Vickers Energy Investments Ltd, Asian Development Bank, Commonwealth Development Corp, International Finance Corp |
| Financing | Multilateral Agencies 91%; loans from shareholders 9% |

[37] Asian Business, "Philippines: Open Arms for Investors", April 1994, p.7

[38] Asia Money, "Power in Asia", December 1995/January 1996, p. 40-41

*Navatos II Power Station – 100 MW, oil-fired plant*

| | |
|---|---|
| Status | 1993 contract completion |
| Cost | US$ 39 million |
| Sponsors | Hopewell Tileman (Philippines) Corp (CEPA's interest 100%) |
| Financing | Equity 25%; Bank Loans 75% |

*Pagbliao Power Station – 2x367 MW, coal-fired*

| | |
|---|---|
| Status | 1996 contract completion |
| Cost | US$ 933 million |
| Sponsors | Hopewell Energy International (CEPA's interest 86.95%), Asian Development Bank, Commonwealth Development Corp, International Finance Corp |
| Financing | Exim credit 73%; multilateral agencies 21%; loans from banks and shareholders 6% |

*Quezon – 440 MW*

| | |
|---|---|
| Status | PPA signed; in progress |
| Cost | US$ 725 million |
| Sponsors | Ogden, Bechtel, PMR |
| Financing | Export credits and multilateral debt from US-Exim and ERG; OPIC political risk insurance |

*Saul Power Station – 2x600 MW, coal-fired plant*

| | |
|---|---|
| Status | 1999 (contract completion; to be amended) |
| Cost | US$ 1.3 billion |
| Sponsors | Panagasian Electric Corp (CEPA's interest 100%) |
| Financing | Exim credit 74%; multilateral agencies 23%; bank loans 3% |

## Thailand

Basic Facts[39]

| | |
|---|---|
| Land Area | 198,115 sq mi (9,561,000 sq km) |
| Population | 60,271,300 |
| GDP (Purchasing Power Parity Terms) | US$ 323 billion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 5,500 |
| National Budget (1994 estimate) | US$ 22.4 billion |
| Currency | Baht (Bt) |
| Exchange rate (May 1995) | Bt 24.63: US$ 1 |
| Change in CPI (inflation) | 5.3 % |
| Electricity | 49.3 billion kWh |

The Power Sector

Thailand's rapid development over the last 20 years has been extremely energy-intensive. From 177 kg of oil equivalent per head in 1971, energy use rose to 614 kg per head in 1992. The apparent absence of any significant supplies of petroleum left the country as one of the largest importers of oil among developing countries at the end of the 1970s. The foreign exchange bill for imported oil, which then accounted for over 80% of energy consumption, reached $2.98 billion in 1981, equal to 33% of all merchandise imports[40]. Thus there has been a major drive to develop indigenous sources of energy in the last decade, notably natural gas, lignite and hydroelectricity. Meanwhile, small deposits of petroleum have been discovered, offering some encouragement for the future.

According to the ADB figures, 57.1 billion kWh of electricity were produced in 1992, and domestic consumption was 49.3 billion kWh. By 1992 the station of Mae Moh had expanded its capacity to 2,025 MW, providing almost 12% of total generating capacity[41]. The natural gas-fired power stations at Bangpakong and on the oilfield at Larn Krubue will provide a further 1,500 MW, while new hydroelectric plants, notably on the Mae Khlong river, will also increase generating capacity. Installed capacity has risen to 14,622 MW at the end of 1993.

[39] World Almanac and Book of Facts 1995, and EIU Country Profile 1995-96: Thailand
[40] EIU Country Profile 1995-96: Thailand, p.21
[41] EIU Country Profile 1995-96: Thailand, p.23

Privatization

In order to meet the growing demand for power, the Electricity Generating Authority of Thailand (EGAT) plans to buy 4,180 MW of power under its Independent Power Producer (IPP) scheme until the year 2002[42]. This figure represents about 50% of the capacity needed because Thailand wants to maintain a 50/50 split between private and public power generation. When bidding for concessions closed in June 1995, thirty two consortiums presented 50 separate proposals to generate a total of 39,000 MW. This response far exceeded expectations of EGAT, which anticipated between 10 and 20 applicants. The bids will be assessed with a 60% weighting on tariff price and 40% weighting on other factors such as supply, diversification and location. The overwhelming response has delayed the selection process. Bidders were expecting a shortlist to be drawn up by October 1995, but EGAT says negotiations for power purchasing agreements (PPA) with the selected few will not begin until July 1996.

A successful and innovative financing structure was employed in late 1994 by the Electricity Generating Public Company (EGCO)[43] (Asia Money 47). The company set up a subsidiary in mid-1994 called the Rayong Electricity Generating Company in order to acquire and operate the Rayong power station, located 200 km south-east of Bangkok. The station is a gas-fired, 1,180 MW plant, which represents approximately 10% of Thailand's installed electricity generating capacity. EGCO raised roughly 45% of the funds to buy the plant by issuing an IPO on the Stock Exchange of Thailand in late 1994. A total of 204 million ordinary shares were offered at a price of Bt 22.00 (88 US cents) per share, raising a total of Bt. 4.4 billion. In addition to the IPO, debt financing was acquired from a number of sources. Onshore banks and debenture holders provided Bt. 7.0 billion and offshore banks while institutional lenders injected a further US$ 282 million. The issue was very well received by investors, many of whom were attracted by the good pricing and a high internal rate of return of around 22%. The shares have

[42] Asia Money, "Power in Asia", December 1995/January 1996, p. 35
[43] Asia Money, "Power in Asia", December 1995/January 1996, p. 47

traded heavily and performed very strongly in the secondary market. One year after listing, the issue is trading-- with the foreign share price at Bt 72 and the domestic share price just slightly lower.

EGCO is now planning a second venture into the capital markets. The company intends to raise capital for the purchase of another power plant EGAT, the 824 MW Khanom plant. EGCO intends to finance the acquisition by raising Bt 21 billion through a combination of new shares, bonds and bank loans. The equity offering is valued at Bt 6 billion. Originally planned for the end of 1995, the issue has been delayed until early 1996 because the government is disputing the tariff rates and wants to review the fee structure. The rate structure is a critical component of the power purchase agreement (PPA), and the equity offering will be postponed until the PPA has been signed.

**Vietnam**

Basic Facts[44]

| | |
|---|---|
| Land Area | 127,246 sq mi (9,561,000 sq km) |
| Population | 74,393,324 |
| GDP (Purchasing Power Parity Terms) | US$ 72 billion |
| GDP per capita (Purchasing Power Parity Terms) | US$ 1,000 |
| National Budget (1994 estimate) | US$ 2 billion |
| Currency | Dong (D) |
| Exchange rate (May 1995) | D 11,053: US$ 1 |
| Electricity | 9 billion kWh |

The Power Sector

Vietnam's power sector has been receiving a large slice of public investment funds in recent years, and output increased at an annual average rate of 9.4% between 1985 and 1992. Major projects completed since the beginning of the 1980s have included the Pha Lai thermal plant (440 MW) and the Hoa Binh hydroelectric project (1,760 MW) in the North, and all four units of the Tri An hydroelectric project (400 MW) in the South[45]. In spite of these additions, production of electricity still remains low: in 1992 it was 141 kWh per head, about half of the level in Indonesia and one-sixth of Thailand's (but twice Bangladesh's output per head).

Three separate, regionally-based companies are responsible for generation, transmission and distribution: Power Company No 1 covering the North; Power Company No 2 covering the South; and Power Company No 3 covering the Central provinces. The electricity supply systems of the Southern and Central regions remain particularly weak. Installed capacity in the Center is nominally 224 MW but less than half of this is actually available. Per head consumption in the center is about 30 kWh, less than a quarter of the national average. Power Company No 3, unlike the other two, does not have an integrated supply system although it now receives about 60 MW of capacity from Power Company No 1 through a 500-km, 220-kv transmission line. In the South, the largest power generator, the Tri An dam, is an erratic source of supply. In

[44] World Almanac and Book of Facts 1995, and EIU Country Profile 1995-96: Vietnam

[45] EIU Country Profile 1995-96: Vietnam, p.46

1992, in the dry season (March-June), there were blackouts in Ho Chi Minh City for up to three days a week. An additional 140 MW, raising output to 12m kWh/day, was expected to ease the shortage to 500-520 kWh/day in 1993, cutting the number of days without power to one during the dry season[46].

To correct the imbalance in supplies between the North and the rest of the country, the government decided in February 1992 to launch a 500 kv, 1,500 km power line linking the Hoa Binh hydroelectric power station and other plants in the North to the deficit regions to the South. The US$ 600 million scheme, described as the country's most ambitious infrastructure project since the building of the Ho Chi Minh trail, was completed more or less on target by mid-1994.

Installed Generating Capacity 1991[47]

| | |
|---|---|
| **Hydro (MW)** | **1,847** |
| Power Company No 1 | 1,280 |
| Power Company No 2 | 563 |
| Power Company No 3 | 5 |
| **Thermal (MW)** | **848** |
| Power Company No 1 | 620 |
| Power Company No 2 | 228 |
| Power Company No 3 | 0.0 |
| **Gas Turbine (MW)** | **118** |
| Power Company No 1 | 24 |
| Power Company No 2 | 60 |
| Power Company No 3 | 34 |
| **Diesel (MW)** | **446** |
| Power Company No 1 | 10 |
| Power Company No 2 | 250 |
| Power Company No 3 | 185 |
| **Total** | **3,258** |

46 EIU Country Profile 1995-96: Vietnam, p.47
47 EIU Country Profile 1995-96: Vietnam, p.47

# APPENDIX 5

## Other Approaches for Improving the Power Situation

The traditional approach of power planners in developing countries has been to focus almost exclusively on building additional generating plants in order to meet growing power demands. There are, however, additional measures that can be taken to improve power supply at substantially reduced costs[48]. These measures can be divided into policy approaches, institutional approaches, and technical approaches, as discussed below.

### *Policy Approaches*

While government policies could play a major role in improving the quality of electricity supply, increasing the efficiency of electricity use, and alleviating the environmental impact of growing electricity consumption in developing countries, in practice, energy and power-sector policies have often failed to achieve these objectives. The Sri Lankan government should pursue policies such as proper pricing of electricity, demand-side management and conservation, and reduction in the environmental impact of power generation.

### *Proper Pricing of Electricity*

An important area requiring reform is energy pricing. Rising energy costs during the 1970s led many countries to introduce energy price controls or subsidies, especially for electricity. As energy costs stabilized in the 1980s, many of these policy interventions have stayed in place, such that energy continues to be supplied at a price

[48] US Agency for International Development, Power Shortages..., p.31

well below its cost to the national economy. In this direct way, energy pricing policies in many countries are encouraging an inefficient allocation of resources and imposing a heavy economic burden on developing countries.

The impacts of such pricing policies are substantial on the energy sector alone. Unrealistically low prices for particular energy delivery forms undermine the financial viability of energy supply institutions. In many countries, pricing policies are major contributors to the financial weakness of electric utilities. Furthermore, low prices reduce the incentives for private sector entreprenuership in the energy sector, as they slow the introduction and use of energy technologies that can contribute to job creation and skill improvement.

In Sri Lanka, tariff setting has been influenced heavily by social factors such as "ability to pay", which has resulted in substantial cross-subsidization within the sector. The cost of supplying electricity to large consumers at a high voltage (33 kV) is generally less per unit than to a low voltage domestic consumer in a rural area, because of factors such as less transformation, transmission and distribution losses, less frequent servicing, and lower meter reading costs when supplying electricity to the former. However, the present tariff structure does not adequately take this into account, as is evident by Table 3.5, and domestic supply has been substantially under-priced. Since the government has been increasingly reluctant to bear the costs for such subsidized sales to households, the CEB has financed its losses by charging large consumers (such as businesses) more than their fair share (from the economic standpoint).

This policy has given domestic consumers fewer incentives to adopt energy conservation measures such as using more efficient fluorescent lamps, while industry has been penalized. The policy has not even had the desired effect of poverty alleviation, since only 30% of the population have access to electricity. The other 70%, who are generally poorer, are actually adversely affected by the higher prices of domestic consumer goods resulting from industries having to pay more for electricity[49].

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[49] Perera, K.K.Y.W, Energy Status in Sri Lanka, p.103

*Demand-Side Management and Conservation*

Few developing countries have adequately considered the substantial impact that energy conservation policies and strategies can have on the provision of additional power while reducing the need for expensive new generation capacity. Government policies could establish equipment standards, building codes, and import restriction or promotion to increase electricity the efficiency of electricity use in the country.

Sri Lanka experimented with a "time-of-day" tariff in the 1980s, in an attempt shifted electricity use from peak times to times when it can be generated more cheaply[50]. The program shifted demand and flattened peaks but was hampered by the inability of the government to institute such two-rate metering system on a wide scale. Therefore, the program was limited to medium and large industries and hotels, and its impact was lessened. Nonetheless the positive results of the experiment indicate that the country can benefit substantially from expanding the use of time-of-day metering and establishing different prices for different categories of customers.

Reducing the Environmental Impact of Power Generation

Power supply expansion in most developing countries has been accomplished with very little concern for the environment. Electric utilities and most donor agencies have traditionally favored large power plants, although smaller plants with cleaner fuels, and lower emissions have less impact on the local environment. At the same time though, a host of technologies and power generation options which minimize environmental impacts are becoming available to most developing countries. Newer technologies, such as fluidized bed combustion of coal, are commercially available and allow developing countries to reduce the adverse impact of power supply on the environment. Providing small hydroelectric facilities in rural areas, cogenerating heat and electricity in industrial facilities, and, above all, using electricity more efficiently are viable and effective options available to power planners. Developing countries need to

[50] Perera, K.K.Y.W, Energy Status in Sri Lanka, p.103

consider environmental impact as one of the major concerns in deciding on a power supply strategy to ensure the widespread and effective use of these strategies.

Governments should adopt policies which define limits on combustion emissions and which restrict the impact of power generation on water resources, air quality, and lifestyle of the population, so that environmental impacts are integrated fully in power-sector planning. In Sri Lanka's case, although the country has a separate Ministry of the Environment, headed by a Cabinet Minster, the country does not have a comprehensive framework for environmental protection nor effective laws for pollution control. A recent World Bank study on the impact of Sri Lanka's power generation on its environment will be a good starting point for the drafting of appropriate legislation.

Institutional Approaches

Once a sound policy is established—on which a sustainable power development strategy can be built, institutions need to be created or improved to implement that strategy. Existing institutional structures in most developing countries are not well-matched to their present power predicament. Developing country power institutions face uncertainty and capital shortage problems, and the political, economic, and technological climate in which they operate is shifting rapidly. Traditional power-sector institutions, however, are typically state controlled and thus designed to implement publicly-financed additions to the power system and operate them using typical public sector management methods. Such methods tend to be inefficient and rigid in adapting to changing situations.

Approaches to institutional development in developing country power-sectors can be categorized as follows[51]:

- Improving institutional structures for utility management, planning, and operations
- Developing capabilities for research and development in the power industry
- Supporting the institutions necessary for conservation and end-use efficiency improvement

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[51] US Agency for International Development, Power Shortages..., p.33

*Utility Management, Planning, and Operational Improvements*

While many of the inefficiencies in the power sector of developing countries are the direct result of ineffective and inappropriate policies, such as irrational prices and other forms of subsidy, they are also caused simply by poor management, planning, and operating practices. The most pressing problems include[52]:

- Lack of attention to manpower development
- Lack of management objectives needed to operate efficiently
- Lack of know-how to improve planning, operation, and management of utilities

Therefore, a new approach is needed to focus utility management systematically on efficient operation. Human resource development is of crucial importance in such a strategy. To achieve this, the government needs to institute a management improvement program which will[53]:

- Review and improve each organization's or sub-organization's goals and plans, and assess the human resources needed to achieve those goals
- Establish a detailed operating program to achieve determined efficiency targets
- Create comprehensive monitoring programs to assess progress towards efficiency targets
- Develop recruitment and succession plans, career paths (including individual training plans) and personnel data bases

*Institutional Development in the Power R&D Industry*

Traditional technologies will be insufficient to meet projected demand for electricity services, and the widespread use of new technology will require indigenous capacity for technological adaptation and innovation. Wide-ranging institutional reforms are required to accelerate the pace of research and development. Even more

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[52] US Agency for International Development, Power Shortages..., p.33
[53] US Agency for International Development, Power Shortages..., p.33

technically advanced developing nations like India and Brazil devote a comparatively small fraction of their budgets to relevant research and development in the power sector, while those such as Sri Lanka perform very little local research. After a country establishes the necessary facilities for local R&D, it should also implement the necessary institutional mechanisms to transfer newly developed technologies to the marketplace.

*Strengthening Institutional Related to End-Use Efficiency*

Institutional needs related to achieving end-use efficiency improvements include[54]:

- Development of institutions (both public and private) to develop and implement a national electricity conservation program effectively
- Establishment of an integrated approach that combines engineering, management, and financial aspects of electricity conservation into a unified process—in practical terms, for example, utilities require demand management departments staffed with specialists from a variety of disciplines including equipment performance, consumer behavior, and end-use analysis
- Establishment of information and training programs to increase awareness of end-use efficiency benefits
- Development of capability within local engineering firms to build a long-term energy conservation services
- Development of equipment research and development, demonstrations, and performance testing capabilities (in order to facilitate this, governments can assist entrepreneurs who are attempting to manufacture and/or market energy-efficient products and services by offering financing, training, and support for technology transfer)
- Establishment of financing programs, including utility financing options, as well as government and third-party financing incentives

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[54] US Agency for International Development, Power Shortages..., p.34

Technological Approaches

With proper policies and institutions in place, developing countries can take advantage of a large variety of technical innovations that can lead to an improved power situation. In this section, I will outline some options available to developing countries to supplement their traditional generation capacity expansion in meeting their burgeoning power demand in a sustainable fashion. Although many other options exist, the six approaches presented below include the major elements of a successful power development strategy:

- Power plant performance improvement
- Transmission and distribution loss reduction
- End-use efficiency improvement
- Load management
- Cogeneration
- New generation technologies

*Power plant performance improvement*

The majority of thermal power plants in developing countries operate below their designed capacity and efficiency, and the amount of time they are unavailable for operation is far greater than of plants in developed countries. In some developing countries, aging plants operate below 80 percent of their rated capacity, and the availability factor of many thermal power stations in these nations is under 60 percent, compared with over 85 percent in the US. Moreover, they use over 13,000 Btu of fuel per kWh of output, compared with 9,000-11,000 Btu per kWh for efficient plants.

The poor performance of thermal power plants is caused by unsatisfactory repair and maintenance, unavailability of spare parts, improper operation management, and poor fuel quality. Resolving these problems—through a combination of technical, operational, and managerial measures—requires a concerted effort on the part of electric utilities and power-sector planners to allocate sufficient to improving performance of power plants.

The positive impact of measures to improve power plants more than justify their cost in many cases. A study of power plant performance improvement in Pakistan, for example, indicates that it is possible to improve fuel use efficiency by 12 percent, and to recover an additional generation capacity of 300 MW from the existing thermal power plants of the Water and Power Development Authority. Since total costs of the process would be approximately US$ 170 million, the payback period for this investment is estimated at under three years[55].

While a comprehensive analysis of the total potential of power rehabilitation has not been carried out for developing countries, the limited data available indicate that, for an inefficiently run system, power plant rehabilitation can increase the available generation capacity by 8 percent to 10 percent, and result in similar improvements in generation efficiency.

The improvement possible through proper planning can be illustrated by the Inginiyagala Power House, a small 10 MW hydro power plant in the Sri Lankan system[56]. If the reservoir is operated at near-maximum level conditions, it is possible to increase annual output by about 16 million kWh, compared to when the reservoir is operated closer to the lowest levels. However, the latter case occurs much more frequently due to constraints which are of a political nature. For example, when farmers see higher water levels, they demand more releases, thus drastically reducing power generating efficiency, costing the CEB about Rs. 30 million during a year with normal rainfall. The unfortunate fact is that with more efficient and independent planning, higher electricity output can be obtained *without detriment* to the quantity of water released seasonally.

It is evident, however, that the optimum management of the much larger power stations at Kotmale, Victoria, and Randenigala and the associated storage reservoirs are of far greater importance. Since releases for agricultural purposes can be at variance with requirements for optimum power generation, an independent party should have

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[55] US Agency for International Development, Power Shortages..., p.36
[56] Perera, K.K.Y.W, Energy Status in Sri Lanka, p.67

the authority to make such decisions in a manner which optimizes both objectives. Measures such as the desilting of reservoir beds can further increase the output of currently operating plants.

*Transmission and distribution loss reduction*

While transmission and distribution (T&D) losses should be below 10 percent of gross generation (economically optimal losses may be as low as 5 percent), in many developing countries they are over 20 percent. In Pakistan, the Dominican Republic, and Egypt, they are 27 percent, 34 percent, and 22 percent respectively[57].

The potential for saving by reducing these losses is enormous. For example, in a country like India with an annual electricity production of about 183 billion kWh (1985-86) and T&D losses of 21 percent, assuming a value of US$ 0.06 per kWh, reducing the losses to 15 percent of generation would yield and annual saving of over $650 million, or about 12 percent of the country's annual power sector budget[58]. These savings can be realized through a modest expenditure in additional hardware.

The technical solutions to high T&D losses are straightforward and do not require any advanced technologies. One of the major causes of high T&D losses in developing countries is low power factor in primary distribution lines. Installation of capacitors could easily remedy this problem. A World Bank study of power systems loss reduction in Sudan (where T&D losses are 32 percent of generation), for example, indicates that installation of static capacitors in the Blue Nile grid at a cost of under 1 million dollars will release 9.4 MW of generation capacity (about 5 percent of total generation capacity in the grid) and about 4.8 GWh of electricity. The benefits from generation capacity saving alone would be over $12 million[59].

The losses in the Sri Lankan system are considerable as evident from Table 3.4. The country's rapid growth in electricity demand could worsen the problem because, if

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[57] US Agency for International Development, Power Shortages..., p.36
[58] US Agency for International Development, Power Shortages..., p.36
[59] US Agency for International Development, Power Shortages..., p.37

conservation efforts are not maintained, the increasing demand will increase the loading on transmission and distribution lines, and the losses can increase four-fold because line losses are proportional to the square of the load (Energy 46). The Lanka Electricity Company, which was one of the earliest utilities to launch a loss reduction program, has already been able to reduce distribution losses from approximately 25% to 13%, even before the full rehabilitation has been completed. Although the CEB is planning to reduce losses to 12%, many contend that 9% is a more feasible target.

*End-use efficiency improvement*

Despite the fact that industrialized countries have made major strides in using electricity more efficiently over the last decade, developing countries have made little progress in this area. The opportunities for improvements are tremendous, and the cost is only a fraction of the generation expansion option.

Over 40 percent of electricity in developing countries is used by electric motors, and use of more efficient motors and speed controls could dramatically reduce this consumption. In the US, for example, the use of variable frequency drive controls in the industrial sector is estimated to reduce electricity needs by 20 percent to 30 percent for each motor and result in a 7 percent reduction in total electricity consumption in the country[60]. The overall savings potential is greater in developing countries where industrial electricity use is of greater importance and many motors operate at partial load. Similarly attractive opportunities for improving efficiency exist in air-conditioning, water pumping, refrigeration, and other electricity end-use applications.

USAID Studies indicate that it is technically possible to increase electricity use efficiency in developing countries by 30 percent at financially attractive terms. A study of Pakistan's industrial and commercial sectors found that they have a cost-effective savings potential of 30 percent of their projected electricity demand by the year 2005. These savings translate into 25,000 GWh of avoided electricity generation and 3,000

[60] US Agency for International Development, Power Shortages..., p.37

MW of avoided generation capacity – over 20 percent of the country's generation capacity expansion requirements[61].

Although a number of energy auditing and energy saving schemes have been instituted by the Sri Lanka Ministry of Power and Energy, this program has been hampered by the lack of the necessary equipment, and adequately trained personnel. In spite of these difficulties the CEB plans to launch a demand side management program in 1996, which will replace regular light bulbs with compact fluorescent lamps (CFLs). The projected electricity savings of the program are presented in the table below[62]:

| | Number of Lamps | Year to be Replaced | Expected Energy Savings (GWh) |
|---|---|---|---|
| Initial | 400,000 | 1996 | 28 |
| Additional | 600,000 | 1997 | 70 |
| Total | 1,000,000 | — | 98 |

**Note: It was assumed that lamps are operated 4 hours a day, and that lamps are in service for 5 years.**

Professor K.K.Y.W. Perera[63] has estimated that the following measures that encourage conservation in the domestic sector will bring about a savings of 30 MW at peak demand time and 30 million kWh units of electricity a year:

- Reduction of wasteful use (through good-housekeeping, and other measures)
- Use of more energy efficient devices (e.g. fluorescent lighting in place of ordinary incandescent bulbs)
- Effective means of discouraging use of heavy domestic appliances (e.g. washing machines) during hours of peak demand
- Encouraging an alternative to electric cooking

Bringing about such measures will require education of domestic electricity users, and the establishment of various price incentives (such as time-of-day pricing)

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[61] US Agency for International Development, Power Shortages..., p.37

[62] Ceylon Electricity Board: Generation Planning Branch, Report on Long Term Generation Expansion Planning Studies 1995-2009 (Colombo, Sri Lanka: October 1994), p.A8-1

[63] Perera, K.K.Y.W, Energy Status in Sri Lanka, p.102

*Load management*

In developing countries where peak demand grows at considerably faster rates than average load, load management—reduction of peak load (peak clipping), the development of off-peak load (valley filling), and the transfer of load from on-peak to off-periods (load shifting)—presents an attractive opportunity for reducing needed additional generation capacity.

USAID studies suggest that there is considerable potential for reducing peak load at attractive terms. In Costa Rica, for example, a study of 12 industrial plants indicates that it is possible to reduce the peak load of these facilities by 21 percent (4,800 kW) at a cost of $50,000 to the utility and US$ 73,000 to the industrial plants. The resulting savings to the utility would be over US$ 500,000, while industry would recover its cost in less than one year[64].

Sri Lanka's limited attempts at load management were discussed earlier in the section "Demand-Side Management and Conservation." As was evident in that discussion, much can be gained by expanding such schemes.

*Cogeneration*

Cogeneration--the simultaneous production of electricity and useful thermal energy—is an important power generation option that has not been fully utilized in developing countries. This process allows industrial and large commercial users to use the waste heat from power generation to reduce their total energy costs, increasing the overall energy efficiency and reducing the need for generation capacity expansion.

A study of the cogeneration possibilities in Pakistan, sponsored by USAID, estimates the potential in industrial plants at about 900 MW although only about 200 MW has been developed. A similar study in the Indian states of Gujarat and Maharashtra estimates the economically and financially attractive cogeneration potential over the next ten years at more than over 2,100 MW, compared with current

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[64] US Agency for International Development, Power Shortages..., p.38

generation capacity of about 10,000 MW[65]. Other studies in Indonesia, the Philippines, Costa Rica, and the Dominican Republic have indicated similarly sizable cogeneration potential in those countries.

*New generation technologies*

There is a variety of new generation technologies which can be used in developing countries to generate electricity more efficiently and to reduce its environmental impact. Furthermore, some new technologies enable developing countries to increase the use of their indigenous natural resources, thus reducing their imported fuel requirements.

For example, some advanced gas turbines have overall energy conversion efficiencies of 50 percent, requiring 20 percent less fuel than the most efficient conventional large thermal power plants. These units combine modularity, short lead times for planning and commissioning, and attractive costs. Recent advancements in coal combustion technologies—in particular, atmospheric fluidized bed combustion (AFBC) and integrated gasification combined cycle (IGCC) systems—combine superior technical and environmental performance with modular design, and construction[66]. These characteristics are directly relevant to the needs of the power sector in many developing countries.

There are also a wide range of indigenous renewable resources that can be used in small power generation facilities that are suitable, in particular, to electricity needs in rural areas. Low-head hydropower, biomass from agricultural residues, wind, and solar systems are cost-effective methods that can be used for rural electrification. Although there is considerable potential for such power generation options, they have been largely ignored by power planners in most developing countries.

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[65] US Agency for International Development, Power Shortages..., p.38
[66] US Agency for International Development, Power Shortages..., p.40

Sri Lanka has access to a variety of economically-viable renewable energy resources which include solar, wind, biomass, and minihydro. Some of these could be utilized to meet part of the country's increased energy demand.

*Solar Energy*

Sri Lanka's location close to the equator assures it of a relatively high and uniform level of insolation. This resource can be harnessed for both water heating and crop drying. Very few households currently use hot water, and the main market for the above activities initially will lie in the commercial and tourist sectors. The use of solar energy for crop drying is important because tea and other crop processing industries consume over a million tons of fuelwood, or an estimated 20% of total consumption, per year.

*Minihydro*

While the Sri Lankan government has emphasized large hydro-power schemes, about 10 MW of small schemes (in the 5-250 kW range) have been operating in the tea estates of the central region since 1925. However, many of these are being abandoned because of the availability of cheap and reliable electricity from the national grid. In addition to existing plants which could be rehabilitated, potential sites for minihydro schemes exist in hilly areas and in the irrigation systems of the north central part of the island.

The CEB estimated that 30 MW of small hydro potential exists in about 60 undeveloped sites, and that about 8 MW of potential exist in about 290 irrigation tanks and reservoir sites[67]. A further 50 MW small hydro potential can be tapped in about 140 sites which can either be rehabilitated or redeveloped.

[67] Ceylon Electricity Board, Report on Long Term...., p.5-11

*Other Renewables*

Apart from solar and minihydro, a number of renewable energy applications are worth exploring. These include generation of biogas from animal wastes, producer gas from rice husks, and wind energy for water pumping and electricity generation in isolated areas[68].

The Energy unit of the CEB carried out a resource assessment study of wind potential, which determined an overall potential of 8 MW/sq. km of open land area, or an overall potential of approximately 200 MW in the south eastern quarter of the island[69]. This region of the country is exposed to both south west and north east monsoonal wind and hence wind plants located here can yield acceptable levels of plant factor. A wind energy project of 10 MW commissioned in the year 2000 would provide a benefit/cost ratio of only about 0.5 at a discount rate of 10%. Therefore, it is apparent that wind energy can be considered only as a future option in economic terms.

*Future Contributions of these Sources*

While some of the above technologies appear promising, a concerted effort is necessary to establish schemes to implement them. The NERSE task force was established by the government of Sri Lanka for this purpose.

It is estimated, however, that even under an optimistic scenario, all of these non-conventional sources will contribute only about 2% of total energy requirements in the 1990s and less than 5% by the year 2000[70]. Nevertheless, even this modest contribution will be useful because it will help reduce dependence on expensive imported oil and scarce domestic fuelwood.

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[68] Munasinghe, Mohan, Energy Analysis and Policy, p.76

[69] Ceylon Electricity Board, Report on Long Term...., p.5-10

[70] Munasinghe, Mohan, Energy Analysis and Policy, pp.76 and 89

# APPENDIX 6

Table A6-1

**Results of BOT Project Cashflow Analyses for Different Selling Prices**
*(Equity Participation: 30%; Discount Rate:15%)*

| | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|
| **Purchase Price (Rs/kWh)** | **2.89** | **3.00** | **3.50** | **4.00** | **4.50** | **5.00** | **5.50** | **6.00** | **6.50** | **7.00** |
| **Purchase Price (US Cts/kWh)** | **6.02** | **6.25** | **7.29** | **8.33** | **9.38** | **10.42** | **11.46** | **12.50** | **13.54** | **14.58** |
| **Diesel 40 MW without purchase guarantee 10 year BOT** | | | | | | | | | | |
| Rate of Return on Equity | 6% | 9% | 24% | 36% | 47% | 56% | 65% | 73% | 81% | 88% |
| Debt Service Coverage Ratio | 1.13 | 1.20 | 1.50 | 1.80 | 2.09 | 2.39 | 2.69 | 2.99 | 3.29 | 3.59 |
| **Diesel 40 MW without purchase guarantee 15 year BOT** | | | | | | | | | | |
| Rate of Return on Equity | 14% | 17% | 29% | 41% | 51% | 60% | 68% | 76% | 84% | 91% |
| Debt Service Coverage Ratio | 1.30 | 1.37 | 1.71 | 2.05 | 2.40 | 2.74 | 3.08 | 3.42 | 3.76 | 4.10 |
| **Kukule Hydro 70 MW all energy dispatched- 15 year BOT** | | | | | | | | | | |
| Rate of Return on Equity | -4% | -3% | 4% | 9% | 14% | 19% | 23% | 27% | 30% | 34% |
| Debt Service Coverage Ratio | 0.83 | 0.86 | 1.01 | 1.15 | 1.30 | 1.44 | 1.59 | 1.73 | 1.88 | 2.02 |
| **Coal 300 MW without purchase guarantee- 15 year BOT** | | | | | | | | | | |
| Rate of Return on Equity | -3% | -1% | 8% | 14% | 20% | 26% | 30% | 34% | 38% | 41% |
| Debt Service Coverage Ratio | 0.81 | 0.85 | 1.05 | 1.25 | 1.45 | 1.65 | 1.85 | 2.05 | 2.25 | 2.45 |

Note:
The options which meet the minimum requirements have been shaded

Table A6-2

**Results of BOT Project Cashflow Analyses for Different Discount Rates**
(Selling Price: 2.89 Rs.kWh; Equity Participation: 30%)

| Discount Rate | 8% | 10% | 12% | 14% | 16% | 18% | 20% | 22% |
|---|---|---|---|---|---|---|---|---|
| **Diesel 40 MW without purchase guarantee 10 year BOT** | | | | | | | | |
| Rate of Return on Equity | 20% | 16% | 12% | 8% | 3% | -1% | -6% | -10% |
| Debt Service Coverage Ratio | 1.66 | 1.48 | 1.32 | 1.19 | 1.08 | 0.98 | 0.89 | 0.81 |
| **Diesel 40 MW without purchase guarantee 15 year BOT** | | | | | | | | |
| Rate of Return on Equity | 27% | 24% | 20% | 16% | 12% | 8% | 4% | 1% |
| Debt Service Coverage Ratio | 2.06 | 1.79 | 1.56 | 1.38 | 1.22 | 1.09 | 0.98 | 0.88 |
| **Kukule Hydro 70 MW all energy dispatched- 15 year BOT** | | | | | | | | |
| Rate of Return on Equity | 9% | 5% | 1% | -3% | -6% | -10% | -14% | -17% |
| Debt Service Coverage Ratio | 1.38 | 1.18 | 1.02 | 0.89 | 0.78 | 0.69 | 0.61 | 0.55 |
| **Coal 300 MW without purchase guarantee- 15 year BOT** | | | | | | | | |
| Rate of Return on Equity | 11% | 7% | 3% | -1% | -5% | -9% | -14% | -17% |
| Debt Service Coverage Ratio | 1.46 | 1.22 | 1.03 | 0.87 | 0.75 | 0.65 | 0.57 | 0.5 |

Table A6-3

**Results of BOT Project Cashflow Analyses for Different Discount Rates**
(Selling Price:3.50 Rs./kWh; Equity Participation: 30%)

| Discount Rate | 8% | 10% | 12% | 14% | 16% | 18% | 20% | 22% |
|---|---|---|---|---|---|---|---|---|
| **Diesel 40 MW without purchase guarantee 10 year BOT** | | | | | | | | |
| Rate of Return on Equity | 36% | 33% | 30% | 26% | 22% | 18% | 14% | 10% |
| Debt Service Coverage Ratio | 2.19 | 1.95 | 1.75 | 1.57 | 1.42 | 1.29 | 1.18 | 1.08 |
| **Diesel 40 MW without purchase guarantee 15 year BOT** | | | | | | | | |
| Rate of Return on Equity | 42% | 38% | 35% | 31% | 27% | 24% | 20% | 16% |
| Debt Service Coverage Ratio | 2.73 | 2.38 | 2.07 | 1.82 | 1.61 | 1.44 | 1.29 | 1.17 |
| **Kukule Hydro 70 MW all energy dispatched- 15 year BOT** | | | | | | | | |
| Rate of Return on Equity | 16% | 12% | 9% | 5% | 2% | -2% | -5% | -8% |
| Debt Service Coverage Ratio | 1.68 | 1.43 | 1.24 | 1.08 | 0.94 | 0.83 | 0.74 | 0.66 |
| **Coal 300 MW without purchase guarantee- 15 year BOT** | | | | | | | | |
| Rate of Return on Equity | 20% | 17% | 13% | 9% | 6% | 2% | -2% | -6% |
| Debt Service Coverage Ratio | 1.90 | 1.59 | 1.34 | 1.14 | 0.97 | 0.84 | 0.74 | 0.65 |

Note:
The options which meet the minimum requirements have been shaded

Table A6-4

**Results of BOT Project Cashflow Analyses for Different Levels of Equity Participation**
(Selling Price: 2.89 Rs./kWh; Discount Rate: 15%)

| Equity Participation | 20% | 25% | 30% | 35% | 40% | 45% | 50% | 55% | 60% |
|---|---|---|---|---|---|---|---|---|---|
| **Diesel 40 MW without purchase guarantee 10 year BOT** | | | | | | | | | |
| Rate of Return on Equity | 2% | 4% | 6% | 7% | 8% | 9% | 9% | 10% | 10% |
| Debt Service Coverage Ratio | 0.99 | 1.06 | 1.13 | 1.22 | 1.32 | 1.44 | 1.59 | 1.76 | 1.98 |
| **Diesel 40 MW without purchase guarantee 15 year BOT** | | | | | | | | | |
| Rate of Return on Equity | 13% | 14% | 14% | 14% | 14% | 15% | 15% | 15% | 15% |
| Debt Service Coverage Ratio | 1.13 | 1.21 | 1.30 | 1.40 | 1.51 | 1.65 | 1.81 | 2.02 | 2.27 |
| **Kukule Hydro 70 MW all energy dispatched- 15 year BOT** | | | | | | | | | |
| Rate of Return on Equity | -7% | -6% | -4% | -3% | -2% | -1% | 0% | 0% | 1% |
| Debt Service Coverage Ratio | 0.77 | 0.80 | 0.83 | 0.86 | 0.90 | 0.94 | 0.99 | 1.04 | 1.10 |
| **Coal 300 MW without purchase guarantee- 15 year BOT** | | | | | | | | | |
| Rate of Return on Equity | -8% | -5% | -3% | -1% | 1% | 2% | 3% | 5% | 6% |
| Debt Service Coverage Ratio | 0.71 | 0.75 | 0.81 | 0.87 | 0.94 | 1.03 | 1.13 | 1.26 | 1.41 |

Note:
The options which meet the minimum requirements have been shaded

Table A6-5

**Results of BOT Project Cashflow Analyses for Different Levels of Equity Participation**
(Selling Price: 4.00 Rs./kWh; Discount Rate: 15%)

| Equity Participation | 20% | 25% | 30% | 35% | 40% | 45% | 50% | 55% | 60% |
|---|---|---|---|---|---|---|---|---|---|
| **Diesel 40 MW without purchase guarantee 10 year BOT** | | | | | | | | | |
| Rate of Return on Equity | 43% | 39% | 36% | 34% | 32% | 31% | 30% | 29% | 28% |
| Debt Service Coverage Ratio | 1.57 | 1.68 | 1.80 | 1.93 | 2.09 | 2.28 | 2.51 | 2.79 | 3.14 |
| **Diesel 40 MW without purchase guarantee 15 year BOT** | | | | | | | | | |
| Rate of Return on Equity | 49% | 44% | 41% | 38% | 36% | 34% | 33% | 31% | 30% |
| Debt Service Coverage Ratio | 1.80 | 1.92 | 2.05 | 2.21 | 2.40 | 2.61 | 2.88 | 3.20 | 3.59 |
| **Kukule Hydro 70 MW all energy dispatched- 15 year BOT** | | | | | | | | | |
| Rate of Return on Equity | 8% | 9% | 9% | 9% | 10% | 10% | 10% | 11% | 11% |
| Debt Service Coverage Ratio | 1.07 | 1.11 | 1.15 | 1.20 | 1.25 | 1.31 | 1.38 | 1.45 | 1.52 |
| **Coal 300 MW without purchase guarantee- 15 year BOT** | | | | | | | | | |
| Rate of Return on Equity | 14% | 14% | 14% | 15% | 15% | 15% | 15% | 16% | 16% |
| Debt Service Coverage Ratio | 1.09 | 1.17 | 1.25 | 1.35 | 1.46 | 1.59 | 1.75 | 1.95 | 2.19 |

Note:
The options which meet the minimum requirements have been shaded

Figure A6-1

**Return On Equity for the Various Plants for Different Levels of Equity Participation**
(Selling Price: 4.00 Rs./kWh; Discount Rate: 15%)

| Equity Participation Level | 20% | 25% | 30% | 35% | 40% | 45% | 50% | 55% | 60% |
|---|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 43% | 39% | 36% | 34% | 32% | 31% | 30% | 29% | 28% |
| Diesel 40 MW, 15 year BOT | 49% | 44% | 41% | 38% | 36% | 34% | 33% | 31% | 30% |
| Kukule Hydro 70 MW, 15 year BOT | 8% | 9% | 9% | 9% | 10% | 10% | 10% | 11% | 11% |
| Coal 300 MW, 15 year BOT | 14% | 14% | 14% | 15% | 15% | 15% | 15% | 16% | 16% |
| Required level | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% | 30% |

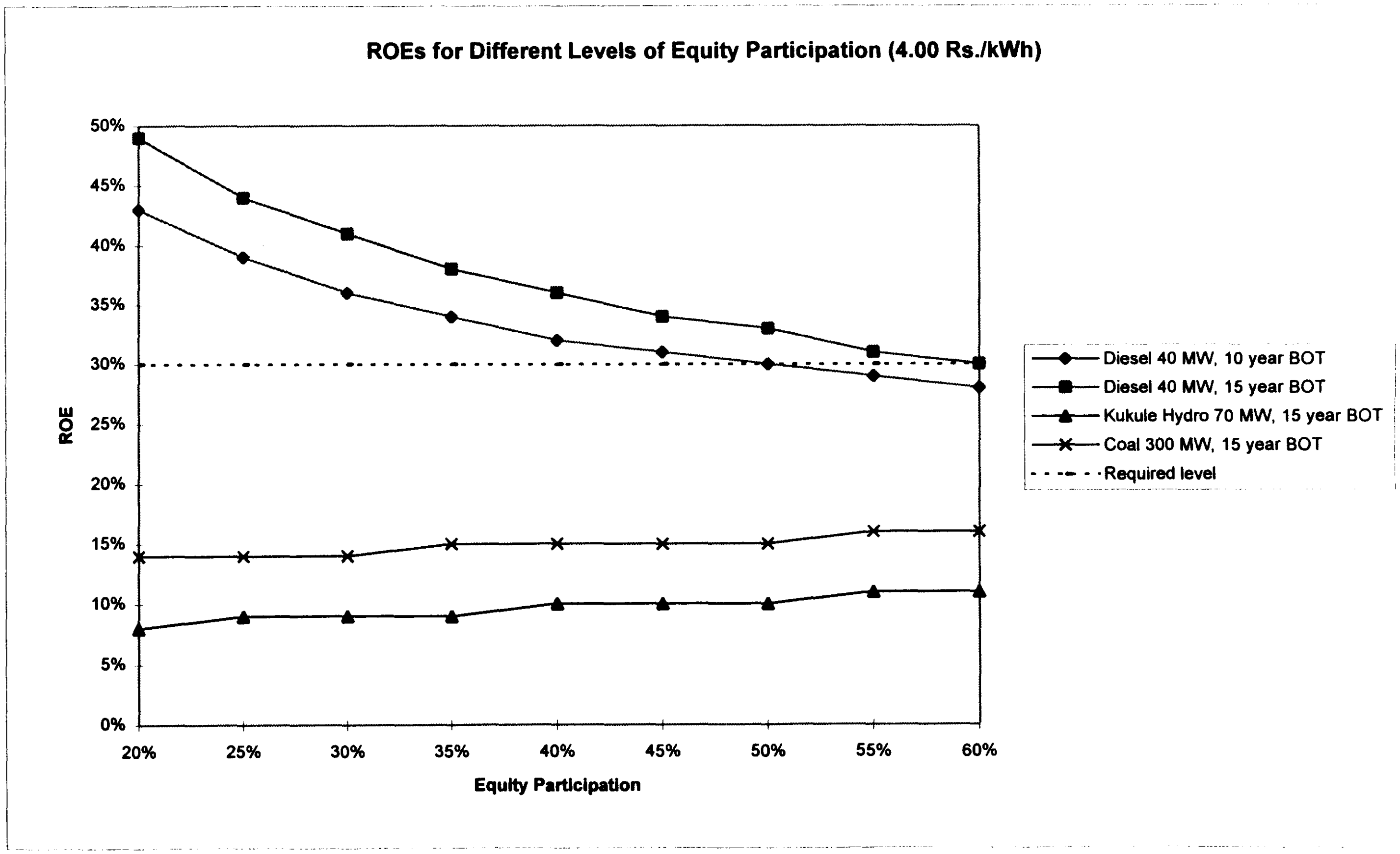

Figure A6-2

**Debt Service Coverage Ratios for the Various Plants for Different Levels of Equity Participation**
(Selling Price: 4.00 Rs./kWh; Discount Rate: 15%)

| Equity Participation Level | 20% | 25% | 30% | 35% | 40% | 45% | 50% | 55% | 60% |
|---|---|---|---|---|---|---|---|---|---|
| Diesel 40 MW, 10 year BOT | 1.57 | 1.68 | 1.80 | 1.93 | 2.09 | 2.28 | 2.51 | 2.79 | 3.14 |
| Diesel 40 MW, 15 year BOT | 1.80 | 1.92 | 2.05 | 2.21 | 2.40 | 2.61 | 2.88 | 3.20 | 3.59 |
| Kukule Hydro 70 MW, 15 year BOT | 1.07 | 1.11 | 1.15 | 1.20 | 1.25 | 1.31 | 1.38 | 1.45 | 1.52 |
| Coal 300 MW, 15 year BOT | 1.09 | 1.17 | 1.25 | 1.35 | 1.46 | 1.59 | 1.75 | 1.95 | 2.19 |
| Required level | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 | 1.50 |

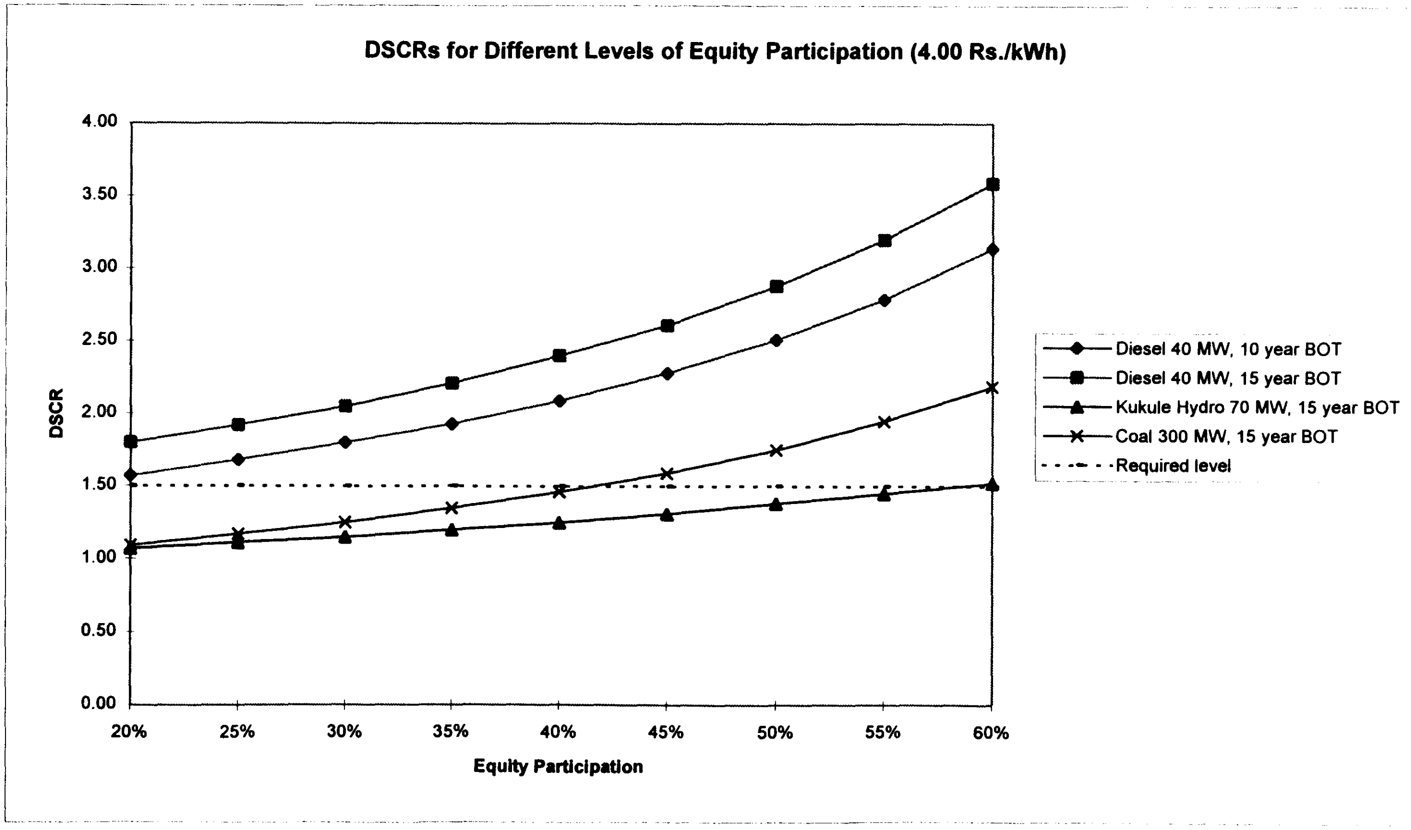

Table A6-6

**ROEs for Different Discount Rates and Equity Participation Rates (Selling Price 3.00 Rs./kWh)**

**Diesel 40 MW, 10 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 29% | 23% | 17% | 10% | 4% | -2% |
| 25% | 26% | 21% | 16% | 11% | 6% | 1% |
| 30% | 23% | 20% | 16% | 12% | 7% | 3% |
| 35% | 22% | 19% | 15% | 12% | 8% | 5% |
| 40% | 20% | 18% | 15% | 12% | 9% | 6% |
| 45% | 19% | 17% | 15% | 13% | 10% | 8% |
| 50% | 18% | 17% | 15% | 13% | 11% | 9% |

**Diesel 40 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 38% | 32% | 26% | 20% | 14% | 9% |
| 25% | 33% | 29% | 24% | 19% | 15% | 10% |
| 30% | 30% | 26% | 23% | 19% | 15% | 11% |
| 35% | 28% | 25% | 22% | 19% | 15% | 12% |
| 40% | 26% | 23% | 21% | 18% | 15% | 13% |
| 45% | 24% | 22% | 20% | 18% | 16% | 13% |
| 50% | 23% | 21% | 20% | 18% | 16% | 14% |

**Hydro 70 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 10% | 6% | 1% | -3% | -7% | -11% |
| 25% | 10% | 6% | 2% | -2% | -6% | -10% |
| 30% | 10% | 7% | 3% | -1% | -5% | -8% |
| 35% | 10% | 7% | 3% | 0% | -3% | -7% |
| 40% | 10% | 7% | 4% | 1% | -2% | -6% |
| 45% | 10% | 7% | 4% | 2% | -1% | -4% |
| 50% | 10% | 7% | 5% | 2% | 0% | -3% |

**Coal 300 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 14% | 8% | 3% | -3% | -8% | -13% |
| 25% | 13% | 9% | 4% | -1% | -5% | -10% |
| 30% | 13% | 9% | 5% | 1% | -3% | -7% |
| 35% | 13% | 10% | 6% | 3% | -1% | -5% |
| 40% | 12% | 10% | 7% | 4% | 1% | -2% |
| 45% | 12% | 10% | 8% | 5% | 2% | 0% |
| 50% | 12% | 10% | 8% | 6% | 4% | 1% |

Note:
The options which meet the minimum requirements have been shaded

Table A6-8

**DSCRs for Different Discount Rates and Equity Participation Rates (Selling Price 3.00 Rs./kWh)**

**Diesel 40 MW, 10 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.53 | 1.37 | 1.23 | 1.10 | 1.00 | 0.90 |
| 25% | 1.64 | 1.46 | 1.31 | 1.18 | 1.06 | 0.97 |
| 30% | 1.75 | 1.56 | 1.40 | 1.28 | 1.14 | 1.03 |
| 35% | 1.89 | 1.68 | 1.51 | 1.36 | 1.23 | 1.11 |
| 40% | 2.05 | 1.82 | 1.63 | 1.47 | 1.33 | 1.21 |
| 45% | 2.23 | 1.99 | 1.78 | 1.60 | 1.45 | 1.32 |
| 50% | 2.46 | 2.19 | 1.96 | 1.76 | 1.60 | 1.45 |

**Diesel 40 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.91 | 1.66 | 1.45 | 1.27 | 1.13 | 1.01 |
| 25% | 2.04 | 1.77 | 1.54 | 1.36 | 1.21 | 1.08 |
| 30% | 2.18 | 1.89 | 1.65 | 1.46 | 1.29 | 1.15 |
| 35% | 2.35 | 2.04 | 1.78 | 1.57 | 1.39 | 1.24 |
| 40% | 2.55 | 2.21 | 1.93 | 1.70 | 1.51 | 1.35 |
| 45% | 2.78 | 2.41 | 2.11 | 1.85 | 1.64 | 1.47 |
| 50% | 3.06 | 2.65 | 2.32 | 2.04 | 1.81 | 1.62 |

**Hydro 70 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.33 | 1.14 | 0.98 | 0.85 | 0.75 | 0.66 |
| 25% | 1.38 | 1.18 | 1.02 | 0.89 | 0.78 | 0.69 |
| 30% | 1.44 | 1.23 | 1.06 | 0.92 | 0.81 | 0.71 |
| 35% | 1.50 | 1.28 | 1.10 | 0.96 | 0.84 | 0.74 |
| 40% | 1.56 | 1.34 | 1.15 | 1.00 | 0.88 | 0.78 |
| 45% | 1.63 | 1.40 | 1.21 | 1.05 | 0.92 | 0.81 |
| 50% | 1.71 | 1.46 | 1.26 | 1.10 | 0.96 | 0.85 |

**Coal 300 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 1.35 | 1.12 | 0.95 | 0.80 | 0.69 | 0.60 |
| 25% | 1.44 | 1.20 | 1.01 | 0.86 | 0.74 | 0.64 |
| 30% | 1.54 | 1.28 | 1.08 | 0.92 | 0.79 | 0.68 |
| 35% | 1.66 | 1.38 | 1.16 | 0.99 | 0.85 | 0.74 |
| 40% | 1.80 | 1.50 | 1.26 | 1.07 | 0.92 | 0.80 |
| 45% | 1.96 | 1.64 | 1.38 | 1.17 | 1.01 | 0.87 |
| 50% | 2.16 | 1.80 | 1.51 | 1.29 | 1.11 | 0.96 |

Note:

The options which meet the minimum requirements have been shaded

Table A6-9

**DSCRs for Different Discount Rates and Equity Participation Rates (Selling Price 3.50 Rs./kWh)**

**Diesel 40 MW, 10 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| **20%** | 1.92 | 1.71 | 1.53 | 1.38 | 1.25 | 1.13 |
| **25%** | 2.05 | 1.82 | 1.63 | 1.47 | 1.33 | 1.21 |
| **30%** | 2.19 | 1.95 | 1.75 | 1.57 | 1.42 | 1.29 |
| **35%** | 2.38 | 2.10 | 1.88 | 1.70 | 1.53 | 1.39 |
| **40%** | 2.56 | 2.28 | 2.04 | 1.84 | 1.66 | 1.51 |
| **45%** | 2.79 | 2.49 | 2.23 | 2.00 | 1.81 | 1.64 |
| **50%** | 3.07 | 2.73 | 2.45 | 2.20 | 1.99 | 1.81 |

**Diesel 40 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| **20%** | 2.39 | 2.07 | 1.81 | 1.59 | 1.41 | 1.26 |
| **25%** | 2.55 | 2.21 | 1.93 | 1.70 | 1.51 | 1.35 |
| **30%** | 2.73 | 2.36 | 2.07 | 1.82 | 1.61 | 1.44 |
| **35%** | 2.94 | 2.55 | 2.23 | 1.96 | 1.74 | 1.55 |
| **40%** | 3.18 | 2.76 | 2.41 | 2.12 | 1.88 | 1.68 |
| **45%** | 3.47 | 3.01 | 2.63 | 2.32 | 2.05 | 1.83 |
| **50%** | 3.82 | 3.31 | 2.89 | 2.55 | 2.26 | 2.02 |

**Hydro 70 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| **20%** | 1.55 | 1.33 | 1.15 | 1.00 | 0.87 | 0.77 |
| **25%** | 1.61 | 1.38 | 1.19 | 1.03 | 0.91 | 0.80 |
| **30%** | 1.68 | 1.43 | 1.24 | 1.08 | 0.94 | 0.83 |
| **35%** | 1.75 | 1.49 | 1.29 | 1.12 | 0.98 | 0.87 |
| **40%** | 1.82 | 1.56 | 1.35 | 1.17 | 1.03 | 0.91 |
| **45%** | 1.91 | 1.63 | 1.41 | 1.23 | 1.08 | 0.95 |
| **50%** | 2.00 | 1.71 | 1.48 | 1.29 | 1.13 | 1.00 |

**Coal 300 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| **20%** | 1.67 | 1.39 | 1.17 | 0.99 | 0.85 | 0.74 |
| **25%** | 1.78 | 1.48 | 1.25 | 1.06 | 0.91 | 0.79 |
| **30%** | 1.90 | 1.59 | 1.34 | 1.14 | 0.97 | 0.84 |
| **35%** | 2.05 | 1.71 | 1.44 | 1.22 | 1.05 | 0.91 |
| **40%** | 2.22 | 1.85 | 1.56 | 1.32 | 1.14 | 0.98 |
| **45%** | 2.42 | 2.02 | 1.70 | 1.45 | 1.24 | 1.07 |
| **50%** | 2.67 | 2.22 | 1.87 | 1.59 | 1.36 | 1.18 |

**Note:**
The options which meet the minimum requirements have been shaded

Table A6-7

**ROEs for Different Discount Rates and Equity Participation Rates (Selling Price 3.50 Rs./kWh)**

**Diesel 40 MW, 10 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 46% | 41% | 36% | 30% | 24% | 18% |
| 25% | 40% | 36% | 32% | 28% | 23% | 18% |
| 30% | 36% | 33% | 30% | 26% | 22% | 18% |
| 35% | 33% | 31% | 28% | 25% | 22% | 18% |
| 40% | 31% | 29% | 26% | 24% | 21% | 18% |
| 45% | 29% | 27% | 25% | 23% | 21% | 19% |
| 50% | 27% | 26% | 24% | 22% | 21% | 19% |

**Diesel 40 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 53% | 48% | 43% | 37% | 31% | 25% |
| 25% | 46% | 42% | 38% | 34% | 29% | 24% |
| 30% | 42% | 38% | 35% | 31% | 27% | 24% |
| 35% | 38% | 35% | 32% | 29% | 26% | 23% |
| 40% | 35% | 33% | 31% | 28% | 25% | 23% |
| 45% | 33% | 31% | 29% | 27% | 25% | 23% |
| 50% | 31% | 29% | 28% | 26% | 24% | 22% |

**Hydro 70 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 17% | 13% | 8% | 4% | 0% | -4% |
| 25% | 16% | 13% | 9% | 5% | 1% | -3% |
| 30% | 16% | 12% | 9% | 5% | 2% | -2% |
| 35% | 15% | 12% | 9% | 6% | 3% | -1% |
| 40% | 15% | 12% | 9% | 6% | 3% | 0% |
| 45% | 14% | 12% | 10% | 7% | 4% | 1% |
| 50% | 14% | 12% | 10% | 7% | 5% | 2% |

**Coal 300 MW, 15 Year BOT**

| | 8% | 10% | 12% | 14% | 16% | 18% |
|---|---|---|---|---|---|---|
| 20% | 23% | 18% | 13% | 8% | 2% | -3% |
| 25% | 21% | 17% | 13% | 9% | 4% | 0% |
| 30% | 20% | 17% | 13% | 9% | 6% | 2% |
| 35% | 19% | 16% | 13% | 10% | 7% | 3% |
| 40% | 18% | 16% | 13% | 11% | 8% | 5% |
| 45% | 17% | 15% | 13% | 11% | 9% | 6% |
| 50% | 17% | 15% | 13% | 12% | 10% | 8% |

Note:
The options which meet the minimum requirements have been shaded

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