PRIVATIZATION AND RESTRUCTURING OF THE ELECTRIC POWER SECTOR IN MALAYSIA: IMPLICATIONS OF PRICING POLICY

by

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ABSTRACT

The privatization of the electric utility in Malaysia in 1990 marked the beginning of a series of restructuring changes within the electric power sector. These reforms were expedited in large part in response to the perceived energy crisis and its constraints on development. As part of the reform, a regulatory agency has been established, along with a new regulatory framework. Independent parties have since entered the industry in the generation sector and power is presently being dispatched by both the privatized utility and these independent power producers.

Many of the impacts of the changes that have been planned and implemented over the past five years are only now being experienced. It is evident that some of the outcomes that have resulted may not have been anticipated, particularly with respect to the excess capacity and the impact on consumer tariffs. While there is much political support for the privatization concept and much interest from the private sector for participation in the development of the industry, tariff increases are not politically very palatable. This poses the potential for conflict, especially within the framework that presently exists.

This thesis analyzes the structural, regulatory and competitive changes that have been adopted within the electric power sector. It focuses on regulatory reform and pricing policy and evaluates the impact of the reform initiatives implemented thus far on system operations and consumer tariffs over the next few years. The policy options available within the existing regulatory framework are analyzed, specifically those that are able to influence the nature and degree of the impact on retail rates. The thesis also identifies alternate approaches to pricing policy and the efficacy of these alternate policies on providing incentives for improvement in operational and economic efficiency. Some conclusions on the success of the privatization and restructuring process in achieving the stated objectives are also presented. The analysis essentially concludes that true competition has not yet emerged in the sector and thus the potential benefits of the restructuring process, including lower consumer prices, are not realized. Regulation and pricing policy need to change to foster fair competition and to produce the desired objectives of improved efficiency and equitable distribution of the resultant benefits.

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List of Abbreviations

APEC	Asia-Pacific Economic Cooperation
ASCOPE	ASEAN Council on Petroleum
ASEAN	Association of SouthEast Asian Nations
ASN	Amanah Saham Nasional
CPI	Consumer Price Index
GDP	Gross Domestic Product
EPU	Economic Planning Unit
GSO	Grid System Operator
IPP	Independent Power Producer
JBE	Jabatan Berkanan Elektrik (Electricity Supply Department)
KLSE	Kuala Lumpur Stock Exchange
METP	Ministry of Energy, Telecommunications and Post
MOF	Ministry of Finance
NDP	New Development Policy
NEB	National Electricity Board
NEP	New Economic Policy
NGDS	National Gas Distribution System
PGU	Peninsula Gas Utilisation
PNB	Permodolan Nasional Berhad
PPA	Power Purchase Agreement
SEB	Sabah Electricity Board
SESCO	Sarawak Electricity Supply Corporation
SMI	Small and Medium Scale Industries
SOE	State Owned Enterprise
TNB	Tenaga Nasional Berhad
UMNO	United Malays National Organisation
YPB	Yayasan Pelaburan Bumiputra

Chapter 1

Introduction

Since independence, many of the infrastructure sectors in Malaysia have remained within government control and ownership. Malaysia continued to experience significant public sector expansion in infrastructure and other sectors through the 1970s and the early 1980s. This trend of nationalization however met with an abrupt halt under the leadership of the Prime Minister Dr. Mahathir. The concept of privatization was first introduced in Malaysia in 1983 under his leadership, and in the second half of the 1980s, implementation of privatization projects began.

There were several objectives of privatization in Malaysia. Some arose from national concerns and national objectives, and others were more specific to the industries being considered for privatization. While these objectives have been varied, central to most privatization projects is the goal of improvement in efficiency and productivity. And implicit within this goal is the understanding that such improvements will then benefit the public at large through improved quality, service, and lower prices.

This thesis will attempt to examine the impacts of the privatization and restructuring of the electric power sector in Malaysia. Specifically, it will focus on assessing the existing regulatory framework and pricing policies that have been developed as part of the restructuring process. How are the consumers being impacted by the these policies? Are the objectives of privatization in fact being achieved through the regulation that exists? And if not, what are the impediments and what are the alternatives? The effectiveness of these regulations and policies in achieving the desired improvements in efficiency and productivity and in protecting the interests of the consumers will be evaluated by analyzing the precise impact on retail rate making and the resultant tariffs. Alternative approaches to pricing and their implications with respect to operational and economic efficiency will also be discussed.

1.1 Background on Privatization

This section attempts to provide the reader with an overview of the privatization trend that has been sweeping the world. The first section presents a historical perspective on privatization by discussing the public sector expansion that preceded it. The transition to denationalization and privatization is then examined, particularly in addressing the motivations and objectives. Finally, this section focuses on the issues inherent in privatization of infrastructure and specifically, the electric power sector.

1.1.1 Government Intervention and Public Sector Development

The degree of government intervention in key sectors of the economy has varied quite significantly over time. With the end of the Second World War and subsequent decolonization, many developing nations embraced the notion of centralized planning and public ownership in many sectors central to industrialization. Government involvement at this level was seen as more effective in achieving the rapid industrialization and development objectives that were desired.[1] In line with this, nationalization of industry was fairly common during the 1940s and 1950s and rapid public sector expansion was observed through the 1960s and early 1970s.

Government intervention in the form of planning, public ownership, and provision of public services was justified on political, social and economic grounds. Central planning was deemed essential to ensure appropriate capital formation and allocation of capital in accordance with development objectives. Public production in many sectors was viewed as necessary given the underdeveloped nature of resources and markets. Additionally, the mobilization of domestic savings for investment necessitated government intervention in light of weak financial markets. Developing countries also felt that infant industries needed to be protected from competition at the early stages of development to support long-term development goals.[2] Substantial social benefits, specifically in the achievement of distributional objectives and in the creation of employment and/or the prevention of unemployment, were also seen as benefits of government intervention.[3]

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[1]Seiji Naya, *Private Sector Development and Enterprise Reforms in Growing Asian Economies*, San Francisco, International Center for Economic Growth, 1990.
[2]ibid.
[3]Richard Hemming and Ali M. Mansoor, *Privatization and Public Enterprises*, Washington D.C., International Monetary Fund, January 1988.

Additionally, certain sectors have traditionally been associated with public ownership, in both developing and industrialized nations alike. In the case of these traditional public enterprises, in particular those involving the use of networks (power generation and distribution, water supply, telecommunications, and transportation), the concept of a natural monopolist -- the case where only a single producer can exploit available economies of scale -- is one of the primary justifications for public ownership. The central role these enterprises play in the livelihood of citizens and in the economy has further rationalized public ownership. Additionally, in these enterprises and others, government intervention has been justified in response to the failure of private markets to secure socially efficient outcomes. These failures arise from the existence of nonexcludable public goods (e.g. national defense and police services), externalities (e.g. environmental issues), and informational asymmetries.

In light of the above considerations, the notion of government involvement as a major contributor to economic growth as well as to social and political stability, and the expanding role of the public sector were rarely challenged at that time. However, the situation changed rather drastically in the mid-1970s with the inability of economies to adjust to external price shocks, in particular the first round of oil price increases, which led to a marked deterioration in macroeconomic performance. The large public sectors were blamed for inflexibility in achieving the necessary adjustment. At the same time, both the efficiency and effectiveness of public sector activities began to be questioned seriously. In developing countries, there arose increasing concern with regards to the limited government resources and the generally declining macroeconomic performance in the 1980s. In a number of developed countries, most notably the U.K. and the U.S., election results conveyed public sentiments for a reduction in the size and scope of government, and this provided additional impetus for the backlash against the public sector.[4]

In many cases, state owned enterprises (SOEs) created new problems of bureaucratic failure. Political interference in the management and operations of these enterprises and multiple and often conflicting objectives from various government departments resulted in inefficiencies. Additionally, regulation and government restrictions on corporate activities, products and location, decreased the range of options available to consumers and in many cases, artificially increased prices by limiting competition. The protection also reduced the incentive for

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[4]ibid, Hemming and Mansoor.

regulated firms to minimize cost and reduced the motivation to adopt innovations that may reduce costs.[5]

Hence, in the late 1970s and early 1980s, the political and economic climate of both developing and developed countries made them receptive to change once again, this time in the form of a reversal of the nationalization strategies promoted in the earlier decades. Privatization, deregulation and liberalization were seen as processes required as part of this transformation, with economic growth being the targeted outcome.

1.1.2 Privatization: Motivations and Objectives

The exact nature, scope, and characteristics of "privatization" are subject to debate. At the broadest level, privatization refers to the widening of the scope and level of private sector activity. More specifically, it can refer to the transfer of commercially oriented State Owned Enterprises (SOEs), activities or productive assets of the government to total, majority or minority private ownership or to private control. In addition to transfer of ownership, privatization may include the transfer of leases and management contracts.[6]

As a process, privatization denotes reducing the roles of government, while increasing those of the private sector, in activities or asset ownership. This can include direct actions such as divestiture and it can also include indirect actions such as the provision of incentives intended to stimulate private-sector investment.[7] Privatization of specific sectors and industries are often associated with restructuring where the industry structure itself is altered to enable private participation in a fair and competitive environment. Restructuring can include segmentation of the industry, introduction of competitive forces and mechanisms, and alteration of the regulatory framework. For the purpose of this thesis, privatization will refer primarily to the transfer of ownership and activities from the public to private sector but will be considered in the context of general economic and industrial restructuring.

Privatization is often justified by portraying the over-extension of public ownership, the poor performance of public enterprises compared with private enterprises and the inherent

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[5]Dennis J. Gayle and Jonathan N. Goodrich, *Privatization and Deregulation in Global Perspective*, New York, Quorom Books, 1992.
[6]Charles Vuylsteke, *Techniques of Privatization of State-Owned Enterprises, Vol I, Methods and Implementation*, World Bank Technical Paper Number 88, 1988.
[7]Gayle and Goodrich.

characteristics of public ownership that gives rise to inefficiency.[8] However, the motivations for privatization may be most adequately conveyed through understanding the objectives and expected benefits of privatization. Again, it is important to realize that the objectives of a privatization program will necessarily vary across countries. The overall objectives may include the following:

- the expansion of the private sector as an engine of growth;
- the introduction of more competition in the economy;
- a change in the public-private sector mix;
- improved efficiency in the public sector;
- a decrease in the rate of public expenditure expansion;
- financing capital investment programs;
- a balanced national budget;
- a decrease in the foreign debt.

The content of the privatization program will accordingly vary with the objective(s) to be achieved. Additionally, the objectives for specific privatization projects may differ from the overall objectives of the program. Specific objectives may include the following:

- achieving a wider ownership of a certain public enterprise;
- improving the performance of a particular public enterprise;
- reducing the financial burden placed on the central government in providing certain services;
- eliminating political interference in a certain public enterprise;
- introducing professionalism in the management;
- increasing the quality of a given public service;
- making the provision of a particular public service more responsive to consumer demand;
- reducing the cost of producing a given service;
- the innovation of new technologies.[9]

Quite often, only a subset of the above will constitute the set of objectives for a privatization program or project, and privatization may only be an element of the overall strategy required to

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[8]Hemming and Mansoor.
[9]Kraiyudht Dhiratayakinant, *Privatization: An Analysis of the Concept and Its Implementation in Thailand,* Bangkok, Thailand Development Research Institute Foundation, 1989.

achieve the state objectives. Privatization experiences vary fairly significantly and are very dependent on the overall goals and objectives of the particular country.

The first privatizations were carried out in the late 1970s and early 1980s. Turkey and Chile were among the first countries to carry them out, but it was Britain that pioneered the first mass privatization of state industry.[10] The privatization efforts were driven by the Thatcher government and continued throughout the decade, with over 30 state enterprises privatized since 1980, including public housing, water, gas, electricity, telephones, steel and most transportation.[11] The Thatcher government felt that privatization would bring both greater efficiency and widespread consumer benefits. The idea was to introduce competition and market discipline into the fields that had been the sole possession of government-owned monopolies.[12] The British privatization experience has generally been quite positive, with many enterprises recording annual gains after historically experiencing annual losses. Japan and France are also cited as countries with considerable experience in privatization. In the case of Japan, it was not financial needs of the government that drove privatization, but instead efficiency in management.[13] France's motivations stemmed from the desire of the Chirac government for broader withdrawal of the state from the national economy (following a period of significant nationalization).[14] France decided to privatize only those firms that operated in a competitive environment, thus disregarding utilities as suitable candidates and avoiding a great deal of controversy and regulatory reform.[15]

Privatization in the developing world is also continuing at a rapid pace, though not as fast as in the developed countries, mainly because of the absence of capital markets and the shortage of credit facilities available to the private sector.[16] Chile is particularly notable for a number of reasons. At the beginning of the privatization program which began very early in 1973, state enterprises played a very significant role with SOE participation in GDP at approximately 39 percent. By 1988, about 550 enterprises (of a total of 596 that existed in 1973) were divested and SOE participation in GDP fell to 16 percent. Generally, the process is viewed as being

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[10]Rupert Bruce, 'Trend That's Sweeping World', *International Herald Tribune*, June 18-19, 1994.
[11]Amnuay Viravan, *Privatization: Financial Choices and Opportunities*, Per Jacobsson Lecture, Bangkok, Thailand, October 13, 1991.
[12]Fuat M. Andic, "The Case for Privatization: Some Methodological Issues" in Gayle and Goodrich, *Privatization and Deregulation in Global Perspective*, New York, Quorom Books, 1992.
[13]Viravan
[14]Thomas D. Lancaster, "Deregulating the French Banking System" in Gayle and Goodrich, *Privatization and Deregulation in Global Perspective*, New York, Quorom Books, 1992.
[15]Centro Veljanovski, "Privatization: Progress, Issues and Problems", in Gayle and Goodrich, *Privatization and Deregulation in Global Perspective*, New York, Quorom Books, 1992.
[16]Andic.

highly successful with many of the objectives achieved, including distribution of ownership, maximization of government revenues, improved efficiency in the private sector, greater investment opportunities and reduction in dependence on the public sector. The success of the Chilean program is attributed to the favorable political and economic environment and the diversity of modes of privatization.[17]

It would be safe to say that the privatization wave is reaching far and wide, although in varying forms and degrees. South and Southeast Asia, Latin America, Eastern Europe, and to a lesser extent, Africa, are all experimenting with privatization programs. However, given the limited time these programs have been in place, the results in many of these countries remain fairly inconclusive.

1.1.3 Privatization of Infrastructure and the Electric Power Sector

Privatization of infrastructure is perhaps a more complex process than privatization of industries in the commercial and manufacturing sectors. Furthermore, the experience with infrastructure privatization programs is also fairly limited. Infrastructure services have historically been associated with central planning and public ownership even prior to the expansion of the SOE sector in the middle of this century. These services include power, transport, telecommunications, provision of water and sanitation, and safe disposal of wastes.[18] These industries are vital to the economy and essential for industry and many supply basic inputs to the manufacturing center.[19] Additionally, these infrastructure services are central to activities of households as well as to competitiveness in international trade and foreign investment. Hence provision of these services is seen as a necessary precondition of growth and one of the major challenges of economic development.

Efficiency and quality in provision of infrastructure services is especially important in light of its central role in the economy. And it was this rationale that was used to justify in part the state's role as provider. The state ownership, operation and financing of infrastructure in the form of public monopolies was additionally justified because of the production characteristics of infrastructure. The technical characteristics that differentiate it from other public enterprises involve the single network aspect of supply and delivery, and the potential coordination of

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[17]Dominique Hachette and Rolf Luders, Privatization in Chile: An Economic Appraisal, International Center for Economic Growth, 1993.
[18]IBRD, *World Development Report 1994*, Oxford, Oxford University Press, 1994.
[19]Veljanovski.

service flows required for such a network. Additionally, economic characteristics of infrastructure involve large economies of scale, dedicated investments that are not convertible (sunk costs), considerable commercial risk, and long time horizon for planning and operation, etc.[20]

Hence, in considering privatization of infrastructure, one must take the characteristics described above into consideration. However, these characteristics do not reflect all aspects of infrastructure or even all the different infrastructure industries. And importantly, where once the technology may not have existed for the unbundling of services or for smaller economies of scale, the state of technology is certainly quite different today. Additionally while progress in the development of infrastructure while under public leadership can be observed, severe inadequacy of services can still be observed in many developing countries. This presents itself in the form of inadequate capacity as well as inadequate quality.

An awareness of the problems inherent in the public provision of infrastructure is growing and this has reinforced the general concern regarding the role of the state in economic activity. In addressing this issue, privatization has recently gained considerable interest and many countries are embarking on programs involving the privatization of infrastructure. However, as mentioned earlier, this form of privatization is perhaps more difficult than others. These industries pose difficult tradeoffs between competition and coordination, and monopoly and regulation. Hence, these privatizations need to be carried out very carefully to ensure increased efficiency, high levels of competition, and avoidance of disruption to industry.

This thesis will focus on the implications of privatization and restructuring of the electricity industry. The electricity industry shares some common characteristics with other infrastructure industries as described above. But there do exist certain characteristics of electricity that set it apart from these other industries. These include the very different physics involved in electricity, the existence of an interconnected grid, and the physical and timing constraints imposed on the system coordinator to maintain system integrity.[21] Similar to other infrastructure services, energy supplies are of strategic economic importance and interruptions or loss of supplies can have severe consequences for the local or national economy, with broad impacts on the population.[22] Economic growth is significantly dependent on the availability

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[20]*World Development Report 1994.*

[21]Extracted from the presentation by John D. Chandley of the California Energy Commission on the California Restructuring Debate during the MIT Electric Utility Program Workshop in Cambridge on October 18, 1994.

[22]Thomas P. Winsor, *Post-privatization: Regulatory Framework and Inssues*, Conference on Post Privatization Challenges and Issues, Kuala Lumpur, Malaysia, 1992.

and reliability of generation capacity and the efficient delivery of electricity. Electricity is particularly important to industry, with not only price and supply affecting the international competitiveness of domestic products, but also the reliability of the service. Availability and reliability of electricity supply is also an important prerequisite for attracting foreign investors.

In developing countries, the growth in electricity demand is quite phenomenal. While electricity demand growth in the U.S. and many other developed countries is fairly moderate in the range of 1 to 3 percent per year, the contrary is the case in many developing countries. The electricity demand growth rates are commonly greater than GDP growth rates for many countries. China's demand growth has been explosive at approximately 13 percent per year, while Indonesia and India have experienced growth rates of 10 and 8 percent respectively. This rapid growth stems from the relatively low existing electricity intensity usage, as well as the rapid population growth and general industrialization trends.

As is the case with other privatization programs, the forces driving electricity privatization vary according to each country's economic needs and political conditions. In many developing countries, national debt and difficulty in public sector financing are overwhelming factors, especially in light of the capital intensity of the electric power industry. Additionally, many countries have also been unable to match electricity supply with demand, resulting in significant shortages especially during peak demand periods. And more generally, many of the public electricity utilities are plagued by planning and operational inadequacies, including overstaffing and poor investment decisions and allocations. Public dissatisfaction with service and performance has become apparent and governments have also become aware of the need for correction and improvement.

Malaysia is plagued with many of the same problems with respect to the electric power sector. It has been difficult for electricity supply to keep pace with the growth in demand, and Malaysia consistently experienced power shortages during the 1980s and early 1990s. These resulted from inadequate generation capacity as well as inadequate transmission and distribution networks. In September 1992, Peninsula Malaysia experienced a severe blackout and this event highlighted the nature of the energy crisis in Malaysia and its potential to constrain continued economic growth and development. In line with Malaysia's privatization policy and in response to the problems being faced in the electricity sector, the nationalized utility was privatized in 1992. This was accompanied by a restructuring of the industry, specifically with the establishment of an external regulatory agency and the introduction of independent power generation, and it is this restructuring that is the focus of this thesis.

1.2 Thesis Overview

Chapter 2 provides the background for the case study of Malaysia. The purpose of this section is to present the larger picture and national objectives within which privatization needs to be considered and analyzed. The first section provides an assessment of the social, political and economic situation both in historical and contemporary perspective. The prevailing development policies are described, including those that pertain to privatization. The second section presents an overview of the energy situation in Malaysia, including an assessment of the energy resources, the institutional framework within which the industry operates, and the energy policies that prevail. Finally, in section three, an introduction to the electric power sector is presented. Included in this section is a discussion of the evolution of the utility, the current demand/supply situation and an overview of the recent structural changes in the industry.

In Chapter 3, the existing regulatory framework is presented, specifically with respect to pricing policies and the procurement of independent power. The bulk of the chapter presents the results of analysis of the existing pricing policies, primarily the tariff control mechanism which determines retail rates. The scenario analysis demonstrates the impacts of variations in this mechanism on consumers in the medium term, namely 1995-2000. The chapter concludes with a discussion of the policy implications of this tariff control mechanism.

Chapter 4 expands upon chapter 3 by considering the overall efficacy of the existing pricing policies. The incentives for operational and economic efficiency are examined and the benefits and disadvantages of the prevailing and alternative policies are discussed. This chapter essentially provides a policy analysis of the various regulatory pricing options.

Chapter 5 presents conclusions for this thesis. It reevaluates the objectives of the electricity privatization program and assesses the success of the restructuring initiatives planned and implemented thus far, in meeting these objectives. Additional issues that require further consideration are also presented.

Chapter 2

Energy and Electricity in Malaysia

2.1 Country Overview

2.1.1 Geography

Malaysia is located in Southeast Asia, just north of the equator. Geographically, it consists of two main physical entities, west (peninsula) Malaysia and east Malaysia, separated by 700 km of the South China Sea. Peninsula Malaysia shares a boundary with Thailand in the north, and is separated from Singapore in the south by a narrow channel of water. East Malaysia is situated on Borneo Island which it shares with Indonesia (Kalimantan) and Brunei. Peninsula Malaysia comprises 11 states and the federal territory of Kuala Lumpur, while East Malaysia comprises the 2 states of Sabah and Sarawak.

Malaysia's land area totals approximately 330,000 sq km and the total coastline measures approximately 4300 km. Peninsula Malaysia is comprised of 40 percent of this land mass and the remaining 60 percent comprises east Malaysia. The population is disproportionately distributed with respect to land mass, with 82 percent of the population living on peninsula Malaysia and only 18 percent living on east Malaysia. In part resulting from this, peninsula Malaysia is much more developed than east Malaysia, especially in terms of infrastructure and services. However, within peninsula Malaysia there exists considerable disparity in development as well. Kuala Lumpur, the capital city, has a population of 1.5 million and is a very developed, modern city. There are no other comparable cities in Malaysia although 3 to 4 other fairly large cities have developed on the peninsula. The rest of peninsula Malaysia is a mix of smaller towns, villages, forests, hills, and coastal areas. Much of the recent development effort has been focused on Kuala Lumpur and the surrounding areas, but large infrastructure projects including highways that span north to south and east to west have also been developed.

Malaysia is abundant in natural resources, namely natural rubber, palm oil, and tin. Many of the rubber and palm oil plantations are located in peninsula Malaysia and tin is also mined primarily in peninsula Malaysia. In addition to these commodities, oil and gas are found in fairly significant quantities, with their distribution fairly evenly split between peninsula Malaysia and east Malaysia. These energy resources will be discussed in greater detail in Section 2.2.

2.1.2 Population

In 1993, the population of Malaysia was estimated at 19 million. Between 1980 and 1990, the annual growth rate was 2.8 percent. This growth rate was higher than that of the previous decade, and it is expected that this rate will continue to increase. In 1985, the prime minister advocated an official policy of increased population growth with an aim for a population of 70 million by the year 2095. The rationale for this has been explained as the need for a significant domestic market capable of sustaining the industrial sector.[23] This policy has met with some domestic opposition as well as international criticism.

Malaysia is fairly unique in the region in light of its multi-ethnic population. Three predominant races, Malays, Chinese and Indians, compose the ethnic mix. The Malays (including the indigenous Bumiputera) are considered native to the country. The majority of Chinese immigration took place in the 19th century with the Chinese developing and working in tin mines and the agricultural sector. The Indians came later in the latter part of the 19th century, primarily as laborers to work on roads and railroads, and on the plantations. In 1980, the Malays constituted 55 percent of the population, while the Chinese and Indians constituted 34 percent and 10 percent, respectively. In 1990, the percentage of Indians remained largely unchanged while the Chinese population decreased to 31 percent of the total and the Malay/Bumiputera population increased to 58 percent.

In addition to the changing mix of ethnicity, there are several other trends that can be noted. Urbanization has been increasing, with 28.8 percent of the population living in urban areas in

[23] Economist Intelligence Unit, *Malaysia, Brunei, Country Profile, 1994-95*, London, 1995.

1970, 34 percent in 1980 and 41 percent in 1990. Additionally, the population density has been increasing, with 42 persons/sq km in 1980 and 54 persons/sq km in 1990.

Standard of living indicators exhibit general improvements over time. Infant mortality rates have been decreasing, with the present rate varying between 11.9 per 1000 in Kuala Lumpur and 23 per 1000 in more rural areas. Life expectancy has been increasing, with a current expectancy of 69.1 years for males and 73.8 years for females. Adult literacy in 1991 was estimated at 30 percent for women and 22 percent for men.[24]

2.1.3 Government and Politics

Malaysia provides an excellent case in demonstrating the difficulty and inherent contradiction in attempting to separate politics from economics and development policy. Economic policy, especially after 1969, has been driven by political considerations to uplift the economic standing of the Bumiputera community. At the same time, however, the economic policies have also been market driven, and are not dominated solely by politics.

2.1.3.1 Governance

Malaya gained independence from Britain in 1957 and subsequently, in 1963 the Federation of Malaysia was established and included the 13 states and Singapore. Singapore separated from the Federation in 1965. A parliamentary democracy system with a prime minister and a cabinet responsible to parliament (modeled after the British parliamentary system) along with a constitutional monarchy form the basis of government. The prime minister has considerable power but is constrained by the political forces within his party and the coalition parties. Much of his ability to move the system, therefore, depends upon his own standing and his capacity to satisfy his party constituency and members of the coalition government.[25]

Since independence, elections have been held fairly regularly. However, the governance since independence has remained with one party, the Barisan National (earlier the Alliance Party), a multinational coalition. Within this coalition, there exists one dominant political party, United Malays National Organisation (UMNO) with its constituency being almost exclusively Malay. As a result of this majority status, the president of UMNO has always been the prime minister

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[24]ibid.

[25]Just Faaland, J.R. Parkinson, Rais Saniman, *Growth and Ethnic Inequality: Malaysia's New Economic Policy*, New York, St. Martin Press, 1990.

of Malaysia. The current prime minister, Dr. Mahathir, has been in power since 1980. He is thought of as a visionary man who has done much for Malaysia's development, but one who maintains a controversial image in the international arena. Dr. Mahatir's landslide victory in the elections earlier this year demonstrate the popularity of his government, its policies, and the economic results that have been achieved.

2.1.3.2 New Economic Policy

Generally, the early years of independence were difficult times fraught with ethnic tensions. The height of these tensions surfaced in the 1969 racial riots, primarily a result of the tension between the Malay's dominant but eroding political power and the Chinese' disproportionately dominant economic power. From 1957 to 1970, the non-Malays had been allowed to participate in the economy with minimal intervention from the government, resulting in considerable dominance of the economy by the Chinese. While general economic growth did result, inequality in distribution worsened and the 1969 riots reflected the Malay population's frustration with this situation.

The government attempted to curb the ethnic tensions with the adoption of the New Economic Policy (NEP) in 1971. Officially, this policy was aimed at "achieving national unity through the two-pronged objectives of eradicating poverty irrespective of race and restructuring society to eliminate the identification of race with economic function."[26] The NEP was essentially an affirmative action socio-economic policy that maintained a system of privileges for the Malays and redistributed the disproportionate economic power in favor of the Malays through a system of quotas, etc. The NEP targeted an increase in Bumiputera ownership in the corporate sector to 30 percent by 1990.

2.1.3.3 Malaysia in the International Arena

Malaysia is a non-aligned country. It is an active member of the Association of SouthEast Asian Nations (ASEAN) along with its neighbors, Thailand, Singapore, Indonesia, Brunei and the Philippines. In 1991, Prime Minister Mahathir proposed setting up an East Asia Economic Caucus (EAEC) to act a trading bloc similar to those of Europe and North America. Up until then, ASEAN was primarily a forum for regional peace and security issues. ASEAN working groups now include an ASEAN Council on Petroleum (ASCOPE) which attempts to

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[26]Government of Malaysia, *The Third Malaysia Plan, 1976-1980*, Kuala Lumpur, National Printing Department, 1976.

coordinate petroleum supply and demand strategies within ASEAN, and a Forum of Heads of ASEAN Power Utilities, which among other responsibilities, attempts to coordinate the ASEAN interconnected grid. Both these councils fall under the larger grouping of the Committee on Industry, Minerals and Energy.

Malaysia is also one of 17 members of the Asia-Pacific Economic Cooperation (APEC) Forum. The APEC forum was established in 1989 to promote greater economic cooperation and trade liberalization in the Asia-Pacific region. APEC working groups include an Energy Cooperation Working Group (EWG), established to maximize the energy sector's contribution to the region's economic development, while safeguarding the environment. The EWG contributes to decision-making through discussion of national energy policies and planning priorities, sharing of basic resource demand and supply outlook data and consideration of regional energy implications of and responses to energy-related issues such as the greenhouse effect.[27]

2.1.4 National Economy

2.1.4.1 Economic Indicators

The Malaysian economy is performing remarkably well, with high growth rates, low government and external deficits, relatively low inflation and low unemployment (see Tables 2.1 and 2.2). It is among the most macroeconomically stable countries today, developing or otherwise. Its success can be attributed to a number of factors including its abundance in natural resources, its strength in the manufacturing sector, and more generally, sound economic and development policies. These policies shall be discussed in detail in Section 1.4.3.

Table 2.1 Gross Domestic Product

Total (RM billion)[28]	1988	1989	1990	1991	1992	1993
At current prices	90.9	101.5	115.1	128.2	143.0	159.7
At constant (1978) prices	66.3	72.1	79.2	86.0	92.8	100.9
Real change (%)	8.9	8.7	9.8	8.6	7.9	8.7

Source: EIU, Malaysia, Country Profile 1994-1995

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[27]U.S. Department of State Bureau of Public Affairs, Office of Public Communication, *Focus on Asia-Pacific Economic Cooperation*, March 16, 1994.

[28]The monetary unit used in Malaysia is the ringgit (RM) or Malaysian dollar (M$), subdivided into 100 sen. In 1993, the exchange rate was valued at RM 2.70 = US $1.00.

Malaysia has not had a consistent history of economic stability and prosperity. In the 1970s, the GDP was growing at an average rate of 8.3 percent. But like many other developing countries, the economic situation worsened considerably in the 1980s, with the economy in recession in the early 1980s. In 1985, Malaysia's real GDP growth was negative (-1.1 percent). In the late 1980s, however, the economy picked up again, and the annual GDP growth rate has exceeded 8 percent every year since 1988.

Table 2.2 Unemployment, Consumer Price Index, GDP per head

	1988	1989	1990	1991	1992	1993
Unemployment rate (%)	8.1	7.1	6.0	5.6	3.9	3.0
CPI increase (%)	2.5	2.8	3.1	4.4	4.7	3.7
GDP per capita growth (%)	6.3	5.6	6.2	7.4	5.6	6.3

Source: EIU, Malaysia, Country Profile 1994-1995

2.1.4.2 Structure of the Economy

The structure of the economy has changed fairly significantly over the past few decades (see Table 2.3). In 1960, the agricultural sector constituted the greatest portion of the economy at 38 percent. By 1993, this share had diminished considerably to 15.9 percent. Conversely, the manufacturing sector has become the economy's main source of growth with its share of the economy increasing from 9 percent in 1960 to 30.1 percent in 1993. The mining sector, like the agricultural sector, has also been losing its strategic role in the Malaysian economy, contributing to 14 percent of GDP in 1970, and only 8 percent in 1993.

Table 2.3 Sectoral Contributions to GDP (1991 - 1993)

Sector Origin	1981 (%)	1986 (%)	1991 (%)	1992 (%)	1993 (%)
Agriculture, Forestry & Fishing	22	21	17	17	16
Mining & Quarying	9	11	9	9	8
Manufacturing	19	21	28	29	30
Construction	5	4	4	4	4
Electricity, Gas & Water	1	2	2	2	2
Transport, Storage & Communications	6	7	7	7	7
Wholesale/Retail Trade & Hotels	12	11	12	12	12
Finance, Insurance & Real Estate	8	9	10	10	11
Government Services	12	12	10	10	10
Other Services	5	2	1	0	0

Sources: East-West Center, Malaysia: An Energy Sector Study and EIU, Malaysia ,Country Profile, 1994-1995

A similar trend can be observed in the nature of exports. In the 1960s, raw materials such as palm oil, tin and rubber, dominated the export market. Today, manufactured goods and high technology products have taken the lead and it is expected that the share of higher-value products will continue to increase.

2.1.4.3 Economic Policies and Development Strategies

New Economic Policy and New Development Policy

Since 1965, the government has been formulating five year development plans to direct national planning and policies. Additionally, there have been longer-term economic policies that have guided the course of development. In 1971, the National Economic Policy (NEP) was adopted as discussed earlier in Section 2.1.3.2.

In 1990, the New Development Policy (NDP) replaced the NEP. The NDP maintains the objectives of the NEP and stresses rapid industrialization and "balanced development" with an emphasis on equity. Within the framework of the policy, strategies are aimed at attaining macro-economic growth with stability, developing human resources, promoting technological capabilities, protecting the environment and ecology, inculcating positive values as well as reducing structural imbalances among sectors and regions in order to strengthen the linkages in the economy.[29]

Vision 2020

The centerpiece of Malaysia's development strategy over the next three decades is the Vision 2020 concept. It was espoused by Dr. Mahathir in 1990 and it envisions Malaysia as a fully developed/industrialized nation by the year 2020.

"Hopefully, the Malaysian who is born today and in the years to come will be the last generation of our citizens who will be living in a country that is called 'developing'. The ultimate objective that we should aim for is a Malaysia that is a fully developed country by the year 2020. By the year 2020, Malaysia can be a united nation, with a confident Malaysian society, infused by strong moral and ethical values, living in a society that is democratic, liberal

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[29]Government of Malaysia, *Mid-Term Review of the Sixth Malaysia Plan. 1991-1993*, Kuala Lumpur, National Printing Department, 1993.

and tolerant, caring, economically just and equitable, progressive and prosperous, and in full possession of an economy that is competitive, dynamic, robust and resilient."[30]

The strategies that will be required to fulfill these objectives are incorporated in the shorter-term development plans, including export-led growth and free market forces, technology intensive industries, internationalization, and the accelerated industrial drive.

Sixth Malaysia Plan

The Sixth Malaysia Plan, which outlines development strategies and goals for the period 1991-1995, generally advocates macro-economic strategies aimed at maintaining high growth without imposing undue adverse consequences on macro-economic stability. Specifically, supply constraints and inflation are to be contained. Private investment is encouraged and the private sector is expected to continue to be the engine of growth. In line with this, measures are being taken to mobilize domestic savings to provide the source of funds required to support the rapid rate of gross domestic capital formation, thereby further strengthening the internal resilience of the economy.

Sectoral strategies include modernizing large-scale commercial production and estatization in the agricultural sector and increasing research and development to increase productivity and to develop labor-saving techniques. The manufacturing sector is seen as the main impetus to economic growth and its structure should reflect a broader composition of activities in both heavy industries and small and medium scale industries (SMIs). New technological adaptation and substantial capital investment are being emphasized for increasing the value added of the manufactured products. The construction sector is expected to continue to grow with investment in large infrastructure programs in aviation, roads and expressways, railways and property subsectors. Additionally, longer term mega infrastructure projects such as the new international airport and the light rail transit system are being developed to keep pace with the rapidly expanding economy.

Generally, the government is encouraging increased private sector participation, especially in infrastructure projects to resolve infrastructural inadequacies such as those existing in the

[30]Mahathir Mohamad, *Malaysia: The Way Forward*, in a speech presented at the Malaysian Business Council, Kuala Lumpur, Feb. 28, 1991.

electricity and water subsectors as well as urban traffic congestion.[31] By 1995, public expenditure (both consumption and investment) was targeted at 23.4 percent of GNP compared with 33.7 and 26.3 percent in 1985 and 1990, respectively.

2.1.5 Privatization Progress in Malaysia

2.1.5.1 The expansion of the State Owned Enterprise (SOE) Sector

During the early post-independence years, from 1957 through 1970, there was minimal SOE sector involvement in the economy. The public sector was primarily involved in infrastructure, specifically the transport, energy, communications, and utilities sectors, as well as the commodity marketing sector. However, this situation changed dramatically after the racial riots in 1969 and with the introduction of the New Economic Policy. Broader state intervention was deemed necessary to overcome "discrimination" of the Bumiputera population, specifically to accelerate Bumiputera participation in industry and commerce through employment and ownership-restructuring targets. Thus, the 1970s was a decade marked by tremendous expansion in SOE participation in commercial, industrial, service and petrochemical exploration sectors, with a growth rate of more than 100 enterprises each year by the mid-1970s. By 1980, there were 1,158 SOEs in existence with 34 percent wholly government owned, 37 percent majority government owned and 30 percent with the government as a minority stakeholder.[32]

It is important to note that there was little concurrent growth in control or monitoring systems for these SOEs and hence there was limited effective management supervision on the part of the shareholders and the government. The performance of these enterprises reflects this in part. While the petroleum sector was highly profitable in the late 1970s and early 1980s, the performance of the other sectors were not as remarkable. Approximately 40-45% of the SOEs were blatantly unprofitable throughout the 1980s. This combined with the fairly rapid expansion in development capital expenditure by many of the SOEs in the early 1980s imposed a fairly significant financial burden on the government.

2.1.5.2 Bumiputera Financial Institutions

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[31]Government of Malaysia, *The Sixth Malaysia Plan ,1991-1995*, Kuala Lumpur, National Printing Department, 1991.
[32]Christopher Adam, William Cavendish and Percy S. Mistry, *Adjusting Privatizaton: Case Studies from Developing Countries*, London, James Currey Ltd., 1992.

Early initiatives of the NEP in pursuit of equity participation targets involved direct compulsory share transfers to Bumiputera individuals and companies. The government established the concept of 'ownership-in-trust' by establishing an investment trust dedicated to the Bumiputera, known as the Yayasan Pelaburan Bumiputera (YPB), in which the government acted as trustee. The Permodolan Nasional Berhad (PNB) was established as an executive agency for the YPB to evaluate, select, and purchase shares in public and private sector companies and to then distribute selected shares to Bumiputera individuals through the Amanah Saham Nasional (ASN) unit trust. In 1981, the 'Scheme of Transfer of Shares held by Government Agencies to Bumiputera Individuals' was launched and involved the transfer of shares in profitable SOEs to the PNB and subsequently to the ASN. ASN has gained tremendous popularity as it offers risk-free investment opportunities due to the generous tax exemptions on dividends and bonuses and the removal of all poor performing equities from the unit by the PNB.[33]

2.1.5.3 Privatization Policies

In 1982, with the election of Dr. Mahathir as prime minister of Malaysia and the onset of economic recession, the creation of new SOEs came to an abrupt halt. Dr. Mahathir advocated the concept of "Malaysia Incorporated" in 1983 whereby the country is viewed as a corporate entity in which the government provides the enabling environment in terms of infrastructure, deregulation and liberalization and overall macroeconomic management, but where the private sector assumes the role as the main engine of growth.[34] In the spirit of this concept, the privatization policy was first announced as a national policy by the government in 1983. The emergence of the policy reflected two concerns, namely the poor performance of the SOE sector and the reassessment of the role of the NEP. Privatization was seen as a continuing means for achieving a greater share of ownership by Bumiputeras while also ensuring that asset values are maintained through the higher overall level of growth and profit within the economy.

Specific guidelines on privatization were issued in 1985 in an official document by the EPU, entitled "Guidelines on Privatization". Within this, five objectives of privatization are cited: (i) reduction of the financial and administrative burden of government, (ii) promotion of

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[33]ibid.

[34]Government of Malaysia, *The Fifth Malaysia Plan, 1986-1990*, Kuala Lumpur, National Printing Department, 1986.

competition and increased productivity of SOEs; (iii) stimulation of private entrepreneurship, investment and growth; (iv) reduction in the role of the state; and (v) promotion of the objectives of the NEP through increasing the supply of private equity.

By mid-1990, there had been approximately 24 major privatization initiatives handled by the EPU. These involved asset sales, including partial sales, and leasing of management contracts as well as build-operate-transfer schemes. Most of them were handled on an ad hoc basis, with little consistency.[35] In 1991, an official Malaysian Privatization Masterplan was released by EPU in which the policy framework, implementation methodologies and planning criteria were presented. Generally, the policy was designed to relinquish commercial management to the private sector and leave the government free to concentrate on traditional functions of maintaining law and order and providing support for achieving growth and distributional objectives.[36] As part of this Masterplan, 430 enterprises were identified as candidates for privatization over the subsequent five year period. This provided considerable momentum for the privatization process and the results of privatization have been much more significant in the first half this decade, both in sheer number of privatizations and in market capitalization.

2.1.5.4 Privatization Process

The Economic Planning Unit is administratively responsible for all privatization projects, including the granting of approval. The determination of the merits of privatization is to be based on the assessment of performance of the privatized entity in terms of efficiency gains, economic growth and relief of administrative and financial burden of the government. The broad policy framework includes limiting government intervention, maximizing competition in privatized industries, enhancing education and training in light of the privatization program, reforming to further promote investment demand, and incorporating fiscal policies to encourage privatization.

The Privatization Action Plan which supplements the Privatization Masterplan consists of a two year rolling plan detailing the entities to be privatized and those to be prepared for privatization. Several factors are taken into consideration in the preparation of this action plan, namely the feasibility for privatization, desirability, impact on economy, absorptive capacity of the domestic capital market, private sector initiated projects and broad-based support for the privatization program.

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[35]Adam et al.

[36]Government of Malaysia, *Privatziation Masterplan*, Economic Planning Unit, 1991.

The privatization can be implemented by several methods including sale of assets or equity, lease of assets, management contract, or build-operate-transfer or build-operate-own schemes. The implementation process will most likely involve commercialization, corporatization, and divestiture.[37]

2.2 Energy Sector

2.2.1 Indigenous Energy Resources: Availability and Role in Economy

Malaysia's success in development has in part stemmed from its energy resource base (see Table 2.4). The availability of these resources has allowed for considerable domestic consumption as weli as a fairly significant share for export. A large petroleum industry has been developed to exploit these resources. In addition to oil and gas, Malaysia is fairly well endowed with hydroelectric power and coal.

Table 2.4 Indigenous Energy Resources

Resource	Reserve
Natural Gas	72 trillion std. cu. ft.
Crude Oil	3.05 billion barrels
Hydroelectric	123,000 GWh (29 GW)
Coal	765 million tonnes

Sources: TNB, Malaysia: Energy Perspectives and ENPEP Experience, and Gas Malaysia.

Natural gas forms the largest portion of the energy resource base, assessed at about 72 trillion standard cubic feet of which 80% are non-associated.[38] The estimate on how long the proven gas reserves will last varies considerably from between 40 years and 100 years. Despite the relative abundance of natural gas, its share of primary energy supply was fairly insignificant until recently. In 1971, the share of natural gas was only 1.4 percent of primary energy supply. This share increased to 20.5 percent in 1980 and to 31.7 percent in 1990, primarily a result of the increasing demand from gas-based industries and the power sector (see Figure 2.1).

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[37]ibid.

[38]Abdul Shukor bin Shahar, *Promotion for Natural Gas Utilisation*, Gas Malaysia Sdn. Bhd., Energy Redc Forum, Malaysia, 26-27 November 1993.

In contrast, the share of crude oil in the primary energy supply decreased over time, from 93 percent in 1971 to 79 percent in 1980 to 52.8 percent in 1990. Gas reserves are about three and a half times greater than the oil reserves in thermal equivalence. Crude oil reserves are generally found in the same area as natural gas. The proven reserves of crude oil are estimated at 3.5 billion barrels and are expected to last between 15 and 30 years. The gas and oil fields are located offshore, of which half are located in peninsula Malaysia and half in East Malaysia.[39] Oil production which increased for some time through 1992 has declined slightly over the past two years to its current level of 648,000 barrels/day.[40] It is important to note that despite the considerable domestic oil resources and production, Malaysia has historically imported a fair amount of crude oil and petroleum products to supplement and complement the country refinery production configuration. Malaysia is expected to become a net importer of oil by the year 2000.[41]

Hydroelectric energy is also an important energy resource for Malaysia, with its potential estimated at about 29 GW or 123,000 GWh/year, approximately 20 percent of the country's total energy resource base. The majority of this potential is located in East Malaysia, with only approximately 13 percent located in Peninsula Malaysia, much of which has already been exploited in contrast to the sites in East Malaysia which have remained largely untapped. The share of hydroelectricity has not altered drastically over the past several decades, but a slight increase can be observed, with a contribution of 3.5 percent in 1971 and 4.3 percent in 1990.

Coal reserves can also be found in Malaysia, primarily in the state of Sarawak in East Malaysia. The reserves are assessed at approximately 764 million tons, with the quality varying from lignite to bituminous and anthracite, and these reserves are expected to last well over 100 years. The coal resources have not been exploited significantly to date primarily as a result of the low quality and high extraction and transportation costs. Much of the coal that is used is imported from Indonesia and Australia. Coal's share in the primary energy supply mix has also increased over time in part to compensate for the drop in the share of crude oil. In 1971, coal constituted 0.5 percent of the mix and in 1990, this share increased to 6.8 percent, largely owing to imports.[42]

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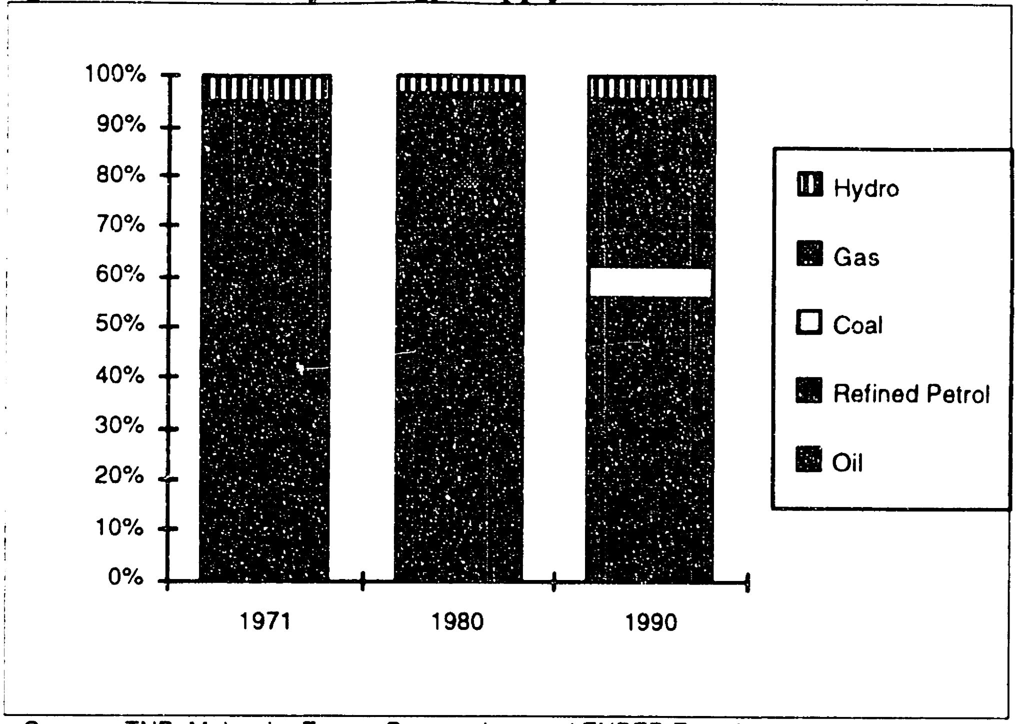
[39]TNB, *Malaysia: Energy Perspectives and ENPEP Experience*, 1992.
[40]EIU.
[41]Doshi, Tilak, 'Southeast Asian Oil and Gas Coming of Age', *Southeast Asian Affairs*, 1993.
[42]TNB, *Malaysia: Energy Perspectives and ENPEP Experience*, 1992.

Figure 2.1 Primary Energy Supply Mix in 1971, 1980, and 1990



Source: TNB, Malaysia: Energy Perspectives and ENPEP Experience

In 1990, primary indigenous energy production was approximately 47,101 ktoe in total, comprising 65 percent crude oil, 32.9 percent gas, 1.9 percent hydro and a small portion of coal (see Table 2.5).[43] The mix of resources within the electricity generation sector also reflects a similar trend, with a decreasing share of oil and an increasing share of gas (see Table 2.5).

It is expected that the share of oil will continue to decrease of the next few years, and that the share of gas and hydro will correspondingly increase. In the long term, it is expected that coal will play a more significant role.

Table 2.5 Indigenous Energy Production

Year	Oil (ktoe)	Gas (ktoe)	Hydro (ktoe)	Coal (ktoe)	Total (ktoe)
1971	3342	73	273	0	3687
1980	13707	2245	383	0	16335
1985	22187	9629	1019	0	32835
1990	30629	15645	915	70	47101

Source: TNB, Malaysia: Energy Perspectives and ENPEP Experience

Energy export from Malaysia has increased at 11.5 percent pa for the 1980-1990 period. Crude oil and petroleum products accounted for 75 percent of the energy exports in 1990, with

[43]ibid.

the remainder contributed by LNG (24 percent) and small amounts of coal and electricity. Malaysia imports crude oil and petroleum products (73 percent of energy imports) and coal (15 percent) and has been a net exporter of oil since 1977.

Table 2.6 Electricity Generation Mix

	Oil	Gas	Hydro	Coal
1980	87%	0%	13%	0%
1985	66%	9%	25%	0%
1990	43%	25%	18%	14%
1993	20%	54%	14%	12%
1995	12%	67%	11%	10%

2.2.2 Institutional Framework

The Economic Planning Unit (EPU) within the Prime Minister's Department is responsible for coordination of all national economic and development planning activities. It chairs and serves as secretariat to the Interagency Planning Group on Energy Development (IAPG) during the various development plan periods. This group has been constituted to advise the prime minister on a broad range of important issues concerning energy within the framework of each planning period. The IAPG includes representation from the Ministry of Energy, Telekoms and Posts, the Ministry of Finance, Tenaga Nasional Berhad and the Electricity Supply Department.[44] Within the EPU, there are two sections that are directly involved with energy planning, the Commerce and Industry section which deals with all sectoral energy projects outside the power sub-sector, e.g. oil refining, and the Infrastructure and Utilities section which deals with power related matters. Additionally, there exists the Petroleum Development Unit within the Prime Minster's Department with the primary responsibility of monitoring the organizations within the petroleum industry including Petronas and Gas Malaysia.[45]

The Ministry of Energy, Telekoms and Posts is responsible for many of the operational functions of the electric power sector. The three utilities in Malaysia, Tenaga Nasional Berhad (TNB), Sabah Electricity Board (SEB), and Sarawak Electricity Supply Corporation (SESCO), all handle the power planning within their respective regions. Prior to privatization, TNB (then known as NEB) was directly responsible to the Minister of Energy, while SEB and SESCO were responsible to the Ministry of Energy, not to the Minister himself, and to their respective states. These entities will be described in further detail in Section 2.3.1.

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[44]Personal communication, Ms. Kamariah, Economic Planning Unit, July 1994.
[45]Government of Malaysia, *National Energy Planning Study*, Vol. III - 4, 1988.

The Treasury Department of the Ministry of Finance plays an important role as it approves all capital projects requiring public funds or international funding channeled through the Government. Additionally, there are several other entities involved in the energy sector, including the Nuclear Energy Unit and the Department of Statistics within the Prime Minister's Department, the Ministry of National and Rural Development, the Ministry of Science, Technology and Environment, and the Federation of Malaysian Manufacturers.

2.2.3 Petroleum Industry

PETRONAS was established in 1974 as a state-owned company with operational responsibilities in the oil and gas sub-sector. Malaysia's Petroleum Development Act gives it exclusive rights over exploration and production of petroleum, including supervising the exploration programs of contracting oil companies (i.e. Esso, Shell, etc.) and gives it authority to negotiate future production sharing agreements. Unlike other government sub-sectoral institutions, it has considerable flexibility in its operations and planning and it is not subject to a rigorous direct review by either the EPU or the Treasury.[46]

Gas Malaysia was formed in 1992 as a privatized utility responsible for natural gas distribution. Its shareholders are the Malaysian Mining Corporation - Shapadu Consortium (55 percent), Tokyo Gas-Mitsui Consortium (25 percent) and Petronas (20 percent). Gas Malaysia is responsible for operating the National Gas Distribution System (NGDS), which was designed to supply piped natural gas to industrial, commercial and residential sectors throughout Peninsula Malaysia. The NGDS is a result of the development of the gas transmission infrastructure under the Peninsula Gas Utilisation (PGU) projects which is described in the next section.[47]

2.2.3 Energy Policy

<u>Oil</u>

Much of the energy policy in Malaysia has centered around oil and its global implications. Production levels of oil in Malaysia have changed considerably over the past two decades, and these levels have been influenced by a number of factors. First, it is important to note that

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[46]ibid.
[47]Abdul Shukor bin Shahar.

Malaysia is not a member of OPEC but has nonetheless often acted in support of the organization's goals, and often in conjunction with ASOPEC. However, in addition to this, production levels are largely dictated by the need for export revenues. It has been a priority to sustain the level of exports by limiting the growth in domestic petroleum consumption. And this has in large part been accomplished through curtailing the share of petroleum use in the power sector, as the power sector was perceived as the most flexible area in which petroleum use can be reduced by switching to other sources of energy [48]

Malaysia has been both an exporter and importer of oil for quite some time, but there has been an emphasis on decreasing the level of imports and generally reducing the dependence on oil to ensure security and reliability of supply. This was explicitly advocated through the four-fuel diversification strategy (oil, hydro, gas and coal) during the Fourth Malaysia Plan (1975-1980), and this diversification strategy has remained central to Malaysia's energy policy. The diversification has been achieved through utilization of non-oil domestic energy resources, particularly gas and hydropower resulting in increasing self-reliance with respect to energy supply and savings in foreign exchange.[49]

Additionally, the National Depletion Policy was formulated in 1980 to delay the development of oil reserves and curtail production as the country attempts to diversify its energy resources and to maintain the availability of reserves for a longer time period. In line with this, oil production is expected to stabilize at 640,000 barrels/day.

Gas

As a result of the substantial gas reserves and the fuel diversification policy, gas has been promoted as the premier alternate fuel for the last several years, especially in the power sector. As part of the promotion for increased natural gas utilization, the Peninsula Gas Utilization (PGU) Projects I, II, and III were developed. PGU I was launched in 1981 and involved the construction of a gas processing plant and an export terminal. These became operational in 1985. PGU II was subsequently launched in 1991 and it involved the laying of a 730 km pipeline system enabling the transmission of gas to growth centers in the southern and western regions of Peninsula Malaysia. PGU II was completed last year. The third phase of the

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[48]Hossein Razavi, 'Coordinated strategy for separate power systems: The case of Malaysia', *Energy Economics*, January 1990.
[49]Government of Malaysia, *The Fifth Malaysia Plan, 1986-1990*, Kuala Lumpur, National Printing Department, 1986.

project, PGU III involves extending the natural gas pipeline system from the south northwards and it is expected that construction will be completed by the end of this year.[50]

While the promotion of gas usage has received much support, it has recently been acknowledged that gas resources, like oil resources, are limited and supplies will be depleted within the next few decades. Petronas has recently adopted a gas usage price cap policy that will be effective in the year 2000. At that time, the power sector will be limited to 60 percent of the gas output at approximately 1300 mmscfd.[51]

Energy Efficiency and Conservation

In conjunction with the fuel diversification policy, the government advocated strategies promoting efficiency and conservation in energy use. The working Committee on Energy Conservation was established and effective from 1982, firms were permitted to generate power for their own use from industrial wastes. In addition, fiscal measures, such as accelerated depreciation allowance for energy-saving industrial machines and equipment, were introduced to encourage more efficient utilization of energy.[52]

During the Fifth Malaysia Plan, appropriate pricing of energy resources and the possibility of establishing National Energy Conservation Center were discussed. However, despite the official promotion of energy efficiency and conservation, there has been relatively little progress that has been made in the area, and it is one where considerable scope for improvement still exists.

Environment

An objective of commitment to the environment was also incorporated in the energy policies of the early 1980s. The Air Quality Act of 1974 empowers the Director General of the Department of Environment to regulate emissions to ensure the environment is protected. The amended Air Quality Act of 1986 mandated preliminary EIA studies for all new energy projects.[53] Beyond the EIA requirement, however, there are few other environmental regulations that stringently enforce the minimization of environmental impacts.

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[50]Abdul Shukor bin Shahar.
[51]Personal communication, Mr. Lu Kok Seng, TNB, July 1994.
[52]Government of Malaysia, *The Fifth Malaysia Plan, 1986-1990*, Kuala Lumpur, National Printing Department, 1986.
[53]TNB, *Malaysia: Energy Perspective and ENPEP Experience*, 1992.

Rural Electrification

Increased coverage of electricity supply to rural areas was greatly emphasized during the Third, Fourth and Fifth Malaysia Plans. Peninsula Malaysia is now 98 percent electrified and Sabah and Sarawak are maintain, but increasing, levels of electrification.

2.3 Electricity Sector

2.3.1 Utilities in Malaysia

In 1949, the Central Electricity Board (CEB) was established and it assumed responsibility for all matters pertaining to electricity. In 1983, the government introduced regulation to form the Electrical Inspectorate that would assume responsibility for safety and licensing activities thus leaving the National Electricity Board to deal with issues pertaining to delivery of service in supplying electricity to consumers in Peninsula Malaysia.[54] However, this apparent separation of activities may be a little misleading as the Electrical Inspectorate was manned almost entirely by NEB's staff seconded to the department and was housed in NEB' s headquarters.[55]

During the 1970s and 1980s, the NEB acquired smaller independent generation and distribution companies with the objective of providing electricity through a sole integrated public electricity authority.[56] NEB, while directly responsible to the Minister of Energy, Telecommunications and Posts, operated as a statutory board with its own board of directors and considerable autonomy with respect to legal and financial matters, and management of employees. For the period 1976-1980, financing of new power projects were derived in part from revenue generated internally (27%) and the remainder through external borrowing from the World Bank and the Asian Development Bank. In 1990, approximately 60 to 65% of the funding was self-generated, and the remainder came from lending institutions including the World Bank and ADB, as well as commercial banks.[57]

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[54]Personal communication, Dr. Mohomad Anas, JBE, August 1994.
[55]Ani bin Arope, *Progress in Tenaga Nasional After Privatization*, PECC: Private Power in the Pacific, Kuala Lumpur, 22-24 March 1994.
[56]Government of Malaysia, *The Third Malaysia Plan, 1976-1980*, Kuala Lumpur, National Printing Department, 1976.
[57]Personal communication, Ms. Zainab binti Abdullah, TNB, July 1994.

By 1990. NEB was supplying more than 95% of the electricity in Peninsula Malaysia and was responsible for all aspects of power supply including generation, transmission and distribution. It owned and maintained the one and only integrated grid in Peninsula Malaysia. Since 1990, however, the utility has undergone considerable transition. In September 1990, it was incorporated under the Companies Act and transformed into its present form as Tenaga Nasional Berhad (TNB), [58] and in April 1992, it was privatized and 25 percent of TNB's shares were floated in the Kuala Lumpur Stock Exchange.

In addition to TNB, two other power authorities exist in Malaysia, the Sabah Electricity Board (SEB) in the state of Sabah and the Sarawak Electricity Supply Corporation (SESCO) in the state of Sarawak. Each of these utilities operated independent grids in East Malaysia. SEB was established as a state authority but was transformed into a federal agency in 1984, operating as a statutory body similar to NEB. SESCO was established as a government-owned corporation. In 1993, it was proposed that SESCO be privatized and that 45% of its shares be acquired by Dunlop.[59]

2.3.2 NEB Regulation Prior to Privatization

Prior to privatization, the National Electricity Board (NEB) was a government statutory body and thus did not require external regulation. Even safety was overseen internally until 1983. Since NEB was essentially a government agency, it was not profit oriented and the tariffs were fixed to enable a return of approximately 6-8 percent on revalued assets, to conform with requirements of the lending agencies such as the World Bank. NEB was exempt from paying taxes and this essentially served as a subsidy to the consumers.[60]

The NEB tariffs were designed to reflect the operating costs of supplying power. However, the tariffs were to be structured so as to ensure that the poor had effective access to electricity as well as to promote the development and dispersal of commercial and industrial activities. In 1975, while the fuel cost variation surcharge had been applied to meet part of the increase in fuel costs, the basic tariffs however, had not been revised since 1964 and with accelerated load growth, expanded construction programs and inflation, the then present tariffs were no longer related to costs of operation. The only major revision was the equalization of tariffs, effective

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[58]Rozali Mohamed Ali, *Private Proviion of Energy Infrastructure in ASEAN: A Review of Status and Issues*, Economic Development Institute of the World Bank, 1992.
[59]Asian Wall Street Journal, December 20, 1993.
[60]Personal communication, Mr. Francis Xavier Jacob, JBE, July 1995.

from the beginning of 1974 between the west coast states served by the national grid and the east coast states served by isolated diesel stations. This action was taken to ensure that the high operating and distribution costs of the diesel stations reflected in the higher rates charged for electricity on the East Coat, would not be a constraint on the development of these areas in line with the overall strategy to redress economic imbalance.

In September 1985, time-of-day pricing was introduced with off-peak rates made available to certain commercial and industrial medium and high voltage consumers. In 1986, NEB revised tariffs again authorizing discounts of 10 percent for hotels and 20 percent for industrial consumers (including heavy industries, textile industries and rubber-based industries). Mining consumers also received significant discounts of up to 25 percent.[61] An additional discount was also provided to the Perjawa steel plant. Generally, the new rates were aimed at accelerating industrialization and tourism. Also, the changes were made to promote better use of the present capacity and to avoid the purchase of expensive generating units for peak demand.[62] The differentiation in pricing and implicit cross-subsidization across sectors continued in this form through 1990. From 1990 through 1992, most of the explicit discounts were removed although the differentiation in pricing across sectors and consumer-type continued to persist. The changes in regulation will be discussed in detail in chapter 3.

2.3.3 Electricity Demand

Electricity demand has been steadily increasing over the past several decades as a result of the growing population and rapid development the country has been experiencing (see Table 2.7). Additionally, the structure of the economy has altered such that the activities and the consumers are now more electricity-intensive. Where once Malaysia was an agricultural economy, it has now transformed into a more advanced economy with manufacturing being the primary engine for growth. Correspondingly, the sectoral consumption share of electricity has been changing, with the share of industrial consumption rapidly increasing (see Table 2.8 and Figure 2.2).

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[61]Millicent Danker and Lisa Totto, *Malaysia: An Energy Sector Study*, Energy Program, Resource System Institute, East-West Center, November 1989.
[62]*The Fourth Malaysia Plan*

Table 2.7 Demand Growth

Year	Sales (GWh)	Peak Demand (MW)
1978	5934	1068
1980	7265	1427
1985	10771	2149
1989	15126	3033
1990	17253	3477
1991	19479	3990
1992	22537	4498
1993	25377	5100
1994		5600

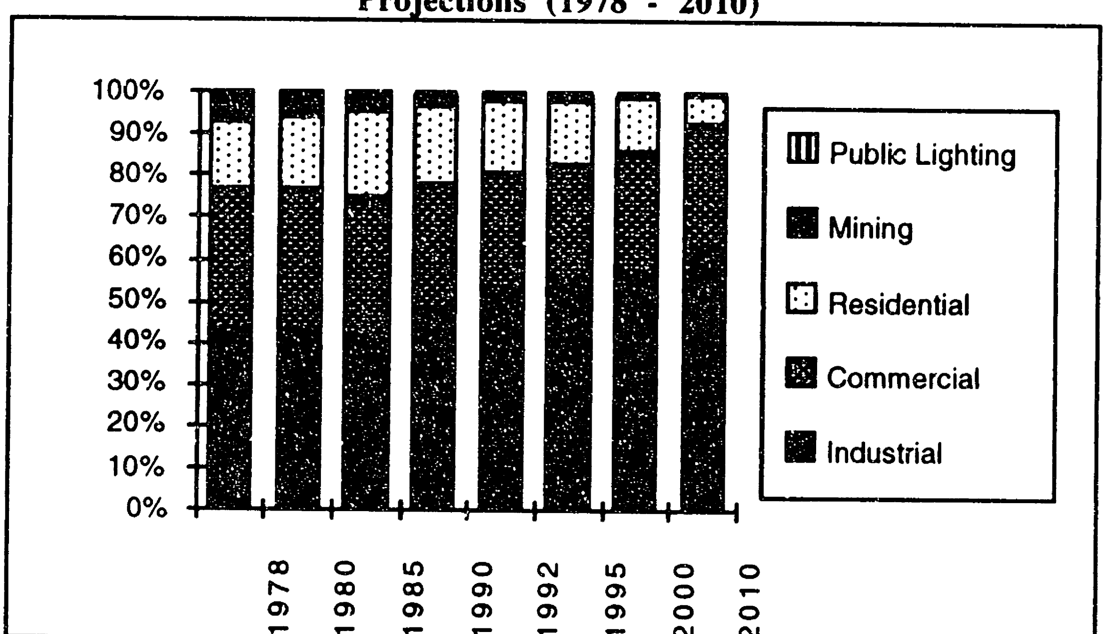
Source: TNB, Malaysia: Energy Perspectives and ENPEP Experience

Table 2.8 Sectoral Consumption Share of Electricity (1978-1995)

Year	Industrial (%)	Commercial (%)	Residential (%)	Mining (%)	Public Lighting (%)
1978	35.54	28.43	13.95	5.12	0.90
1980	36.50	28.61	15.27	3.91	0.86
1985	40.94	33.34	20.88	3.90	0.94
1990	47.62	29.87	19.42	2.25	0.85
1992	52.28	27.76	17.78	1.40	0.78
1995	55.70	26.47	16.24	0.92	0.67

Source: TNB, Malaysia: Energy Perspectives and ENPEP Experience

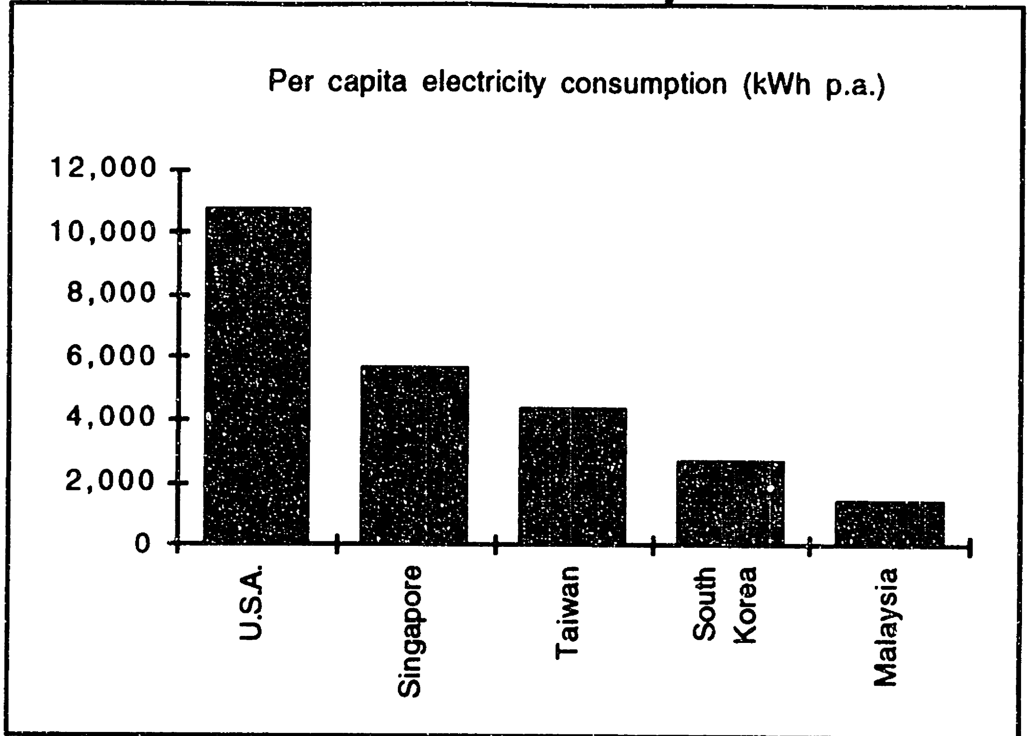
Figure 2.2 Sectoral Consumption Share of Electricity -- Historical Data and Projections (1978 - 2010)



Source: TNB, Malaysia: Energy Perspectives and ENPEP Experience

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 (see Table 3.4). Electricity demand growth has consistently outpaced GDP growth and this trend is expected to continue in the future. Additionally, the per capita electricity consumption in Malaysia is currently very low in comparison to other rapidly developing countries including South Korea, Taiwan and Singapore (see figure 2.3). All these factors contribute to the strong potential for further growth in electricity demand. It has been projected that demand will double its current level by the year 2000 with an average annual growth rate of 10-12 percent. Detailed projections are presented in Chapter 3.

Figure 2.3 Per Capita Electricity Consumption for U.S., Singapore, Taiwan, South Korea and Malaysia



Source: TNB

2.3.3 Electricity Supply

It has been difficult for electricity supply to keep pace with the growth in demand, and Malaysia consistently experienced power shortages during the 1980s and early 1990s. These resulted from inadequate generation capacity as well as inadequate transmission and distribution networks. In September 1992, Peninsula Malaysia experienced a severe blackout and this event highlighted the nature of the energy crisis in Malaysia, and its potential to constrain continued economic growth and development.

The reserve margin of electricity supplied had declined from 33 percent in 1990 to 19 percent in 1993, below the satisfactory level of 25 percent. Consequently, several short-term and long-term measures were incorporated to overcome the shortage constraints. Localized load shedding was introduced during peak hours.[63] Certain demand-side management measures were also introduced, namely time-of-day pricing, standby generation and interruptible supply. In addition to these measures, the government privatized the electric utility and initiated the Independent Power Producer (IPP) Program and licensed several independent power

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[63] *The Sixth Malaysia Plan*

producers to supplement capacity expansion of TNB. Concurrently, a fast-track program was initiated to quickly bring on-line new plants on the part of TNB and several of the IPPs.

Table 2.9 TNB Installed Capacity by Plant Type (1980 - 1991)

Year	Hydro (MW)	Diesel (MW)	Gas Turbine (MW)	Steam (MW)	Combine Cycle (MW)	Total (MW)
1980	613	399	112	1210	0	2334
1981	613	439	141	1330	0	2523
1982	613	445	166	1560	0	2784
1983	726	478	166	1612	0	2982
1984	913	563	348	1612	0	3436
1985	1322	603	347	1570	600	4442
1986	1426	590	382	2090	870	5358
1987	1426	577	381	1930	870	5184
1988	1427	574	381	2230	870	5482
1989	1421	557	384	2530	870	5762
1990	1431	495	384	2490	870	5670
1991	1431	444	486	2490	870	5721

Source: ASEAN Energy Review, Vol 3, May 1993

2.3.4 TNB Privatization Process

In 1987, the government commissioned a study in which the possibility of privatization of NEB was subjected to a detailed examination. After much debate about the most effective 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 the NEP and NDP
- to facilitate economic growth[64]

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[64]Ani bin Arope

The first step in the privatization process was taken by incorporating the entity 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.[65] Additionally, the regulatory framework was drastically altered, primarily with the introduction of the Electricity Supply Act through which the Department of Electricity Supply (DES), also known as Jabatan Berkanan Elektrik (JBE) was created. All legal and regulatory provisions were transferred to this department. Within this context, JBE is responsible for ensuring adequate electricity supply and quality for current and future needs, and reasonable pricing and protection for customers. While JBE was established through an 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. [66] JBE and the existing regulatory framework is described in detail in chapter 3.

The next phase in the privatization process was the flotation of shares in the domestic capital market through the Kuala Lumpur Stock Exchange (KLSE) in April 1992. At that time, only 25 percent of the equity was divested (RM 3 billion in shares). This decision was made for a number of reasons. First, the significant size of TNB was no doubt overwhelming in light of capital market capacity limitations. Additionally, the partial divestiture reduced the valuation problems imposed by the time constraint for the asset transfer. Partial divestiture reduced the risk of adverse impacts of the process and potential mistakes. Additionally, it allowed the strategic infrastructure to remain within national control with the government retaining a controlling interest in the corporation.[67] Since then however, the divested share has increased to close to 35 percent and in 1993, TNB maintained a market capitalization of RM 29.1 billion and accounted for 15.5 percent of the KLSE.[68]

2.3.5 Independent Power Producer Program

The IPPs were born out of three primary needs - to alleviate the power shortage problems, to introduce competition and to lessen the financial burden on TNB/the government. The

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[65]Rozali.
[66]Personal communication, Dr. Mohamad Anas, JBE, August 1994.
[67]Ani bin Arope.
[68]Business Times, July 20, 1993.

privatization of TNB had in essence been the necessary step to prepare for competition. In 1992, the government (EPU) basically announced its interest in introducing competition vis a vis the Independent Power Producer Programme. Thereafter, the private sector provided unsolicited proposals, consistent with the guidelines of the Privatization Masterplan. There was a very loose framework for the processing and acceptance of these proposals and to date, no concrete framework or set of guidelines has been issued.

It is well known that the entire process of IPP negotiations and approval was very politically sensitive. Two of the consortiums were explicitly invited by the government and for the others, the composition of shareholders and investors were also influenced by political connections and implicit government policy. The terms negotiated were also very favorable to the IPPs with fairly low risk and high purchase prices. The details and implications of their contracts will be discussed in Chapter 3.

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. 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.

The impact of these independent power producers and the changes that have that have resulted with their introduction in the sector will be assessed in chapter 3. Specifically, the consumer tariff impacts of the contracts that have been negotiated between TNB and these IPPs and the regulatory framework within which they operate will be evaluated.

Chapter 3

Post Privatization Regulatory Impacts on Consumer Tariffs, 1995-2000

3.1 Post-privatization Regulatory Framework

3.1.1 Electricity Act, 1990

When NEB was privatized in 1990 becoming TNB, the Electricity Supply Department was formed and assumed responsibility for regulatory and inspectorate functions. The Electricity Supply Act of 1990 was established to provide the legislative framework for regulation. This Act was also formulated to facilitate the privatization process and to introduce competition in the form of independent power producers. Under the Act, the Director General of Electricity Supply is specifically charged with the duty of promoting competition in the generation and supply of electricity and ensuring that consumers obtain optimum supply of electricity at reasonable prices. Under the provision of section 26, Electricity Supply Act 1990 (Act 447), a licensee shall levy such tariff as approved by the Minister. In considering and analyzing the tariff for approval, the Electricity Supply Department was to ensure, among others, that provisions in Section 4 of the Act are complied with, namely:

- to promote the interests of consumers of electricity supplied by licensees in respect of the prices to be charged and the other conditions of electricity supply.
- to secure that licensees are able to finance the carrying on of the activities which they are authorized by their licenses[69]

[69]JBE. Publication on the Tariff Control Mechanism, 1993.

3.1.2 The Malaysian Grid Code

The Malaysian Grid Code was introduced in late 1994 by the Director General of JBE as part of his mandate within the Electricity Supply Act to promote competition and to provide a comprehensive regulatory framework for IPPs. The grid code provides criteria guidelines and procedures, in the form of technical, operational and planning requirements, for the licensees of electric power systems connected to the grid, to ensure coordination of the development and operation of a safe, secure, reliable and economical electricity supply grid system.[70] The grid code is to be administered by the Malaysian Grid Code Committee through a Grid System Operator who will be empowered by the Department of Electricity Supply. At the present time, the Grid System Operator is TNB and the Grid Code Committee consists of a Chairman from the Department of Electricity Supply, two members from the Department of Electricity Supply, two member representative of the Grid System Operator, ten members representative of TNB, and two members representative of each Generator (other than TNB). The grid code allows for the possibility of additional distributors and transmitters other than TNB in the future, in that they will be allowed representation within the Grid Code Committee.

The Grid Code is divided into four main sections, namely planning code, system operations code, scheduling and despatch code, and connection code. Highlights of these codes are provided in Appendix B. The following are excerpts relevant to this chapter, from the scheduling and despatch code:

5.2 MERIT ORDER OPERATION

5.2.1 To meet the continuously changing demand on the Grid System in the most economical manner, Generating Units should be, as far as practicable, put on load and loaded up in accordance with the least variable "operation and maintenance cost inclusive of cost of fuel and consumables" (hereinafter "O&M costs") of producing electricity from each Generating Unit. Fixed costs are not taken into considerations. At any time a minimum total amount of plant, with the least variable O&M costs, is used to meet the demand with a satisfactory margin.

5.2.2 For this purpose Generating Units are listed according to the least variable O&M costs of producing electricity from each Generating Unit, and such a list is known as an 'Order-of-Merit-Schedule'.

5.2.3

a. Merit Order for scheduling **on and off** the system: the cost for each Generating Unit is derived from the average heat rate.

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[70]Government of Malaysia, *The Malaysian Grid Code*, JBE, 1994.

5.2.6 ECONOMIC DESPATCH

c. Plant which is required to run for security or inflexibility purposes is allocated first. This is followed by Hydro Plant allocation in accordance with the required Hydro Operation regime. Selection of plant to meet the remainder of the total required capacity is then made from the Thermal Merit Order Tables starting with the highest merit plant (least variable operation and maintenance costs) available until the required total is accumulated.

Additionally, the introductory remarks addressing the incorporation of previously negotiated Power Purchase Agreements are particularly relevant:

1.1.4 It is recognized that prior to the introduction of this Grid Code, Generation Licensees have concluded Power Purchase Agreements which may be at variance to the provisions of this Grid Code. Nothing contained in this Grid Code is intended to modify the parties' rights and obligations under the Power Purchase Agreement. In the event of any conflict, the Power Purchase Agreements take precedence only to the extent that it does not affect the security and safety of the Grid System.

Within the following analysis, dispatch is assumed to follow the least variable O&M cost guidelines.

3.2 The Tariff Control Mechanism

From 1987 to 1993, the structure of the tariff remained essentially unchanged and allowed TNB to earn a rate of return in the range of 6 to 8 percent. In 1992, the need for a new tariff formula was highlighted and in 1993, the present tariff control mechanism was introduced and subsequently implemented on September 1, 1993.

3.2.1 The Average Tariff Formula

The Electricity Tariff Control Mechanism is composed of two distinct elements. The first part incorporates the CPI-M price formula and applies only to TNB supply. The second element incorporates the previously negotiated purchase prices in conjunction with the transmission and distribution price and additionally allows for fuel cost pass through outside the benchmark fuel price range.

The formula is structured as follows:

$$A = [P\,(1 + (CPI - M) / 100) + Y] \times (1 - S_1 - S_2 \ldots) + (IPP_1 + Y_1 + N_1) \times S_1 + (IPP_2 + Y_2 + N_2) \times S_2 + \ldots] + K$$

where

A	=	average tariff for the coming year
P	=	non-fuel component of the average tariff for the base year 1992
CPI	=	consumer price index
M	=	efficiency potential and investment needs of TNB
Y	=	fuel-cost-pass-through component consisting of TNB average fuel costs per kWh in base year (1992) and fuel cost-pass-through for TNB
IPP_x	=	purchase price by TNB from IPP_x
Y_x	=	fuel-cost-pass-through for IPP_x
N_x	=	cost of transmission, distribution, maintenance and profit margin with the purchase from IPP_x
S_x	=	percentage of total system capacity of IPP_x
K	=	correction factor

It is important to emphasize that the structure of the formula was publicly presented as stated above, along with the explanations presented above. However, it seems that in fact the formula is to be interpreted differently, as has been clarified by the regulatory agency, JBE. Clarification of these variables and identification of persisting ambiguities are presented in the following section.

3.2.2 Definition and Discussion of Variables

A (Average Tariff)

In Malaysia and in most other countries, tariffs vary across sectors, across regions, etc. Hence the average tariff derived from this formula is simply that -- the average of the range of tariffs applicable. Since the mid-1980s, industry has been charged considerably lower electricity rates than residential consumers. In total, twelve different tariff schemes exist at present, with the highest rates being charged to domestic (residential) and low voltage commercial customers, and the lowest rates being charged to medium and high voltage industrial consumers. This trend is expected to continue for some time with the government continuing to provide incentives for increased industrialization. It is thus TNB's responsibility, with government oversight, to appropriately weight the changes in average tariff to maintain the existing distribution or to comply with new government policies regarding this distribution.

P (Price)

While the original public documentation indicated that the referenced price to be indexed to inflation was to reflect the average tariff of the base year 1992, this now seems to be incorrect. Instead the P variable is to reflect the tariff from the previous year. Whether this implies that P should be equated with the average tariff A of the previous year remains unclear. At the present time, the interpretation taken equates P with the adjusted P from the previous year, namely [P (1+(CPI-M)/100) +Y] from the previous year.[71] In the subsequent analysis, both interpretations will be considered and the resulting implications will be discussed.

CPI (Consumer Price Index)

In light of the change in interpretation of P, the CPI is to reflect the *increase* in CPI over the previous year, essentially reflecting inflation. CPI figures are published monthly by the Statistics Department. The non-fuel component of price is escalated by 'CPI-M'.

M (Efficiency Factor)

The M factor reflects the room for improvement in the efficiency and operations of the TNB plants. An M factor of zero signifies optimal performance with little or no room for improvement. Hence, the tariff can be adjusted by the full level of inflation. The first determination of the M factor was based on an engineering and management audit of TNB, with TNB's plants compared to other plants throughout the world. Based on this audit, the M factor was set at 2 percent in 1993.

Y (Fuel Cost Pass Through)

This factor includes the benchmark fuel cost and additional costs that are incurred when the price of fuel falls outside the specified range (see Table 3.1). This factor allows for fuel costs which are largely outside TNB's control to be passed through in the tariffs. It includes the benchmark fuel cost (which consolidates all fuels) when the actual fuel cost is within the range of +/- 10 percent of the benchmark cost, and the excess fuel costs outside this range.

[71]The adjustments thathave been proposed thus far by TNB assume this interpretation.

Table 3.1 Range of Prices for Fuel Component, Y

Range of Prices for Fuel Component, Y (sen[72]/kWh)	
Ceiling	7.31
Benchmark	6.65
Floor	5.98

IPP_X (IPP Purchase Price)

There exists some ambiguity regarding the calculation of this parameter. In only one case was there a fixed purchase price negotiated between TNB and the IPPs. In all other cases, capacity and energy rates were negotiated in the form of two-part tariffs. The equivalent purchase price in sen/kWh for these two-part tariff agreements can be calculated by dividing the total capacity and energy payment by the energy output produced by the plant in question for a given month. But in the case where the energy output is small, this results in a very high purchase price. More importantly, in the case of zero output, this calculation results in an undefined value. Hence an alternate strategy for determining IPP price is to calculate the purchase price from all IPPs in aggregate. This does distort the weight of each plant's price contribution, but may be the only workaround available given the existing formula. This issue will be discussed further in the following analysis.

Y_1 (Fuel Cost Pass Through for IPPs)

The IPP purchase prices include the benchmark fuel cost and hence only deviations in fuel price in excess of the allowed 10 percent range are included in this factor.

N (Transmission and Distribution Cost)

The term cost is slightly misleading as this value includes a profit margin allowable for TNB. The specifications on this profit margin remain unclear and at the present time, this value is simply determined by deducting generation costs from the present tariff and allowing for a return on this net value.

S (Percentage of Total System Capacity)

This factor simply weights the price contributions by reflecting the percentage of total generation capacity.

[72] The monetary unit used in Malaysia is the ringgit (RM) or Malaysian dollar (M$), subdivided into 100 sen. In 1993, the exchange rate was valued at RM 2.70 = US $1.00.

K (Correction Factor)

The K factor provides for a correction to the maximum allowed average revenue per unit in the coming year in circumstances where forecasting errors in prior years have lead to an actual average revenue per unit which is above or below the maximum allowed in that year under the price formula. The K factor is not included directly within the following analysis as it is a post-tariff determination policy tool, but will be discussed as such in chapter 4.

3.2.3 Frequency of Tariff Adjustment

The average tariff is determined yearly, but is reviewed every 3 months to allow for changes in fuel prices. Table 3.2 provides details on the frequency of individual factor adjustments.

Table 3.2 Frequency of Tariff Factor Adjustments

Variable	Frequency of Adjustment
CPI-M	once a year
M	once in 4 years
Y	4 times a year
K	once a year

3.2.4 Sample Tariff Adjustment

The following is an example of the calculation required to determine the tariff adjustment for the last quarter of 1993, with no IPPs yet on-line.

Beginning September 1, 1993,

CPI = 4.25%

M = 2%

Non-fuel component P = Average tariff for base year (1992) - benchmark fuel cost

= 19.73 - 6.65

= 13.08 sen/kWh

(CPI-M)/100 = .0225

P (1 + (CPI-M)/100) = 13.08 + .3 = 13.38 sen/kWh

P (1 + (CPI-M)/100) + Y = 13.38 + 6.65 + Y Pass Through

= 20.03 sen/kWh + Y Pass Through

3.3 IPP Power Purchase Agreements

As discussed in chapter 2, the process of approval and negotiation of IPP proposals and power purchase contracts was fairly ad hoc, with few guidelines and specifications. The resultant terms negotiated between TNB and the IPPs are accordingly varied. These highlights of the power purchase agreements are presented in Table 3.3 and are discussed in further detail in the following sections.

3.3.1 IPP Contracts

YTL Sdn. Bhd.

The first proposal for private power generation approved by the government and first license awarded was to YTL in 1992. YTL negotiated the terms of the power supply and power purchase with TNB, and the result of these negotiations was a fairly unique set of terms comprising a fixed purchase price over the entire duration of the contract of 21 years under take or pay terms. Initially, it was agreed that YTL would make available a minimum of 75 percent of capacity and that TNB would purchase at minimum, 75 percent of the capacity, irrespective of whether the plant was actually dispatched at this level, at a fixed price of 15.5 sen/kWh. YTL faces a penalty if 75 percent is not made available. YTL may do as it wishes with the additional capacity available, including the option of selling the additional power to TNB. The terms for additional supply and purchase were not specified within the original contract.

As it turns out, the details of the purchase price are more complex than had originally been perceived. YTL is licensed to own and operate two plants, one on the West Coast of Malaysia with a capacity of 404 MW, and one on the east coast of Malaysia at a capacity of 808 MW. The rates negotiated for these plants differ resulting from the proximity to the natural gas pipeline and general ease of access. The purchase price negotiated for the Paka plant located on the East Coast has a base rate of 12.5 sen/kWh compared with the price negotiated for the Pasir Gudang plant on the West Coast of 15.5 sen/kWh. Additionally, both agreements have discounts for weekends and holidays. For the purpose of this analysis, certain assumptions were made. First, the discounts negotiated for weekends and holidays were not taken into consideration.[73] Instead, constant rates of 15.5 sen/kWh and 12.5 sen/kWh were used for the

[73]The discount rate negotiated for the Pasir Gudang plant is approximately 14 sen/kWh. It is not expected that an incorporation of this rate wiu affect the results significantly, but nonetheless, the effect will be a marginal reduction in consumer tariff.

respective plants. Second, for the output produced and sold to TNB in excess of the 75 percent baseline level, the purchase price was assumed to remain the same as had been negotiated for the base 75 percent.

Table 3.3 IPP Power Purchase Agreement Terms

	YTL	Segari	Genting Sanyen	Powertek	PD Power
Location	(1) Paka, Terrenganu (2) Pasir Gudang, Johor	Lumut, Perak	Kuala Langat, Selangor	Alor Gajah, Melaka	Tanjung Gemuk, PD
Capacity	808 MW 404 MW	1303 MW	720 MW	440 MW	440 MW
Plant Type	2 CCGT block	CCGT	CCGT	OCGT	OCGT
Project Cost	RM2.6 bil	RM3.6 bil	RM1.0 bil	RM719 mil	RM685 mil
Tariff Pricing	One-part tariff; with minimum take	two-part tariff; fully dispatchable base load	two-part tariff; fully dispatchable base load	two-part tariff; fully dispatchable peaking	two-part tariff; fully dispatchable peaking
License Issue Date	7 April 1993	15 July 1993	10 June 1993	1 December 1993	1 December 1993
PPA w/ TNB Date	31 March 1993	16 October 1993	6 January 1994	10 December 1993	10 December 1993
Finance	EPF, Bank Bumi Malaysia	Malayan Banking, Bank Bumi	Malayan Banking	Malayan Banking	Malayan Banking
Commission Date	1995	1996/1997	1996	1995	1995
Shareholders	YTL Corp.	Sikap Power 75%, ABB 25%	Genting 40%, TNB 20%, British Gas, 20%,	Cergas Unggul 35%, Arab Malaysia 30%, Yayasan Melaka 20%, Dato Dr. Mokhzani 8%, Lim Ewe Jin 7%	Sime Darby 40 %, MRCP 30%, Hypergantics 20%, TNB 10%

<u>Segari Energy Ventures Sdn. Bhd.</u>

Segari was the next IPP to negotiate its terms with TNB. It signed a 21 year agreement with TNB for a 1300 MW combined cycle power plant in Lumut, Perak. The plant will consist of two 656.5 MW blocks to be completed in 1996 and 1997. The 21-year term period can be extended for three additional five-year periods with agreement by both TNB and Segari.

As was the case with YTL, the EPU was called upon to facilitate the negotiation process. As perhaps can be expected from the absence of clear guidelines for the determination of purchase rates and structures, the terms negotiated by Segari were quite different from that of YTL. The contract included a fairly standard two-part tariff structure including a capacity payment to cover the fixed and capital costs of the project and an energy payment to cover the variable costs, including fuel, for the electrical power generated The plant is to be fully dispatchable. The rate information for the Segari contract has been obtained and is used in the subsequent analysis. Nonetheless, the specific rates will not be disclosed since the information was obtained confidentially.

Genting Sanyen Power

Genting Sanyen's proposal for a 720 MW combined cycle power plant was accepted by the EPU and METP in 1993. Similar to Segari's power purchase agreement, TNB has agreed to pay an annual capacity charge and an additional energy payment for costs incurred while the plant is dispatched. This project like all other IPP projects is expected to provide a rate of return in the range of 15 to 20 percent, with minimal risks. The loans are expected to be repaid within a 10 year period.

No information on the purchase rates negotiated between TNB and Genting Sanyen were available. For purposes of this analysis, rates equivalent to those negotiated for Segari were used.

Powertek and PD Power

In 1993, proposals from both these IPPs were accepted by the EPU for the commissioning of fast-track gas-fired open-cycle plants within a one-year period to assist in relieving the perceived energy crisis. Both IPPs negotiated contracts to own and operate 440 MW open cycle power plants. These plants were intended to operate as peaking plants on a fully dispatchable basis. Both contracts involved two-part tariffs with capacity and energy payments. The rate structure for these contracts is as follows:

Capacity Rate: RM 28.61/kW per month
Fixed Operating Rate: RM 4.69/kW per month
Energy Rate: 1.25 sen/kWh (when called to supply electricity)[74]

Both the capacity and fixed operating rates contribute to the determination of capacity payment while the energy payment is derived from the energy rate (in conjunction with dispatch level). The same structure was used in the contracts for Segari and Genting Sanyen and a detailed explanation of the payments resulting from these rates is provided in the following section.

[74]Yap Leng Kuen and B.K. Sidhu, 'Focus', *Star Business*, Malaysia, December 12, 1994; these rates were not confirmed beyond this citing.

3.3.2 Two-Part Tariff Payments

As mentioned in the previous section, four of the five IPPs negotiated two-part tariff agreements consisting of a capacity rate, a fixed operating rate and an energy rate. These rates translate into capacity and energy payments with the following formulas:

Capacity Payment

CP = DC * (CRF + FOR) * F * (AF / AT)

where

CP	=	Capacity Payment in Ringgit for the Capacity Billing Period
DC	=	Average of the dependable capacity of the facility for the capacity billing period (kW)
CRF	=	Capacity Rate Financial (RM/kW/month)
FOR	=	Fixed Operating Rate that is adjusted every 4 years by an adjustment factor, based, among others on the CPI (RM/kW/month)
F	=	factor set at 1.0 if AF is greater than or equal to 80%; set at 0.95 if AF is greater than or equal to 65% but less than 80%; set at 0.9 if AF is greater than or equal to 50% but less than 65%; set at AF/AT if AF is less than 50%
AF	=	Availability Factor (%)
AT	=	Availability Target; set at 87% if AF is less than 87%; set equal to AF for values of AF equal to or greater than 87% (and additional complexities) (%)

Energy Payment

EP = (E * H * NEO) / 1,000,000 + VOR * NEO + S

where

EP	=	Energy Payment in Ringgit
E	=	Weighted average cost of fuel (RM/MMBTU)
H	=	Net heat rate (BTU/kWh)
NEO	=	Net Electrical Output for the energy billing period (kWh)
VOR	=	Variable Operating Rate to be adjusted every 4 years by an adjustment factor based among other, on the Producer Price Index for Malaysia
S	=	(no. of startups requested by TNB x 15.5 MMBTU per start-up) / 1,000,000[75]

[75]Francis Xavier Jacob, Privatization and Regulation of the Power Sector in Malaysia, JBE, 1994.

3.4 Factors Influencing Average Tariff

To understand the implications of the new tariff control mechanism and the contracts negotiated between TNB and the IPPs, it is important to understand the factors involved and their possible range of values. Multiple factors may contribute to the determination of a given variable value within the tariff formula. Certain factors have less flexibility than others and hence are more constraining. These include the actual capacity and energy rates negotiated, the duration of the power purchase agreements and the currently approved level of IPP generation. Other factors, including demand growth, transmission and distribution pricing, inflation, fuel costs, efficiency of TNB operation, plant dispatch levels and the future mix of TNB/IPP generation are more susceptible to change and uncertainty. In the following analysis, I will attempt to highlight the implications of the all these factors. Additionally, the range of values for each factor to be used in the subsequent scenario analysis will be identified.

3.4.1 Demand Growth

Demand level does not directly impact the average tariff, but rather indirectly influence it through its implications for capacity factors for the IPP plants. These capacity factors in turn influence the IPP price per kWh specified within the tariff formula (see section 3.4.6 for further clarification)

Electricity sales have been growing rapidly in Malaysia over the past few years, reflective of the high economic growth that has prevailed (see Table 3.4). It is expected that this trend of high electricity growth will continue in the short term in light of the continued emphasis on industrialization and strong and sustained economic growth, but in the long term, will gradually decline. However, as is always the case with projections, there is considerable uncertainty inherent within them and in the past, demand projections have been indeed proven to be fairly unreliable. Hence in planning and forecasting exercises, it is important to project a variety of possible scenarios.

There are a number of factors that influence electricity demand including population growth, GDP growth, fuel prices, natural resource endowments, and intensity of consumption. Additionally, depending on the emphasis placed on energy efficiency, the resulting growth projections can also vary significantly. Several official projections have been forecasted by various agencies in Malaysia, including TNB and JBE. Based on these varying forecasts, I have chosen to model three sets of demand projections as specified in Tables 3.5 and 3.6 (see

Figure 3.1). A general trend of decreasing growth can be observed within these projections consistent with the forecasted decreases in economic growth, especially in the long term. Additionally, the power shortages that existed in the early 90s will likely not continue beyond 1995, thus stabilizing peak demand growth.

Table 3.4 Historical Electricity Demand Growth

Year	Growth
1990	14%
1991	13%
1992	16%
1993	13%
1994	13%
1995	13%

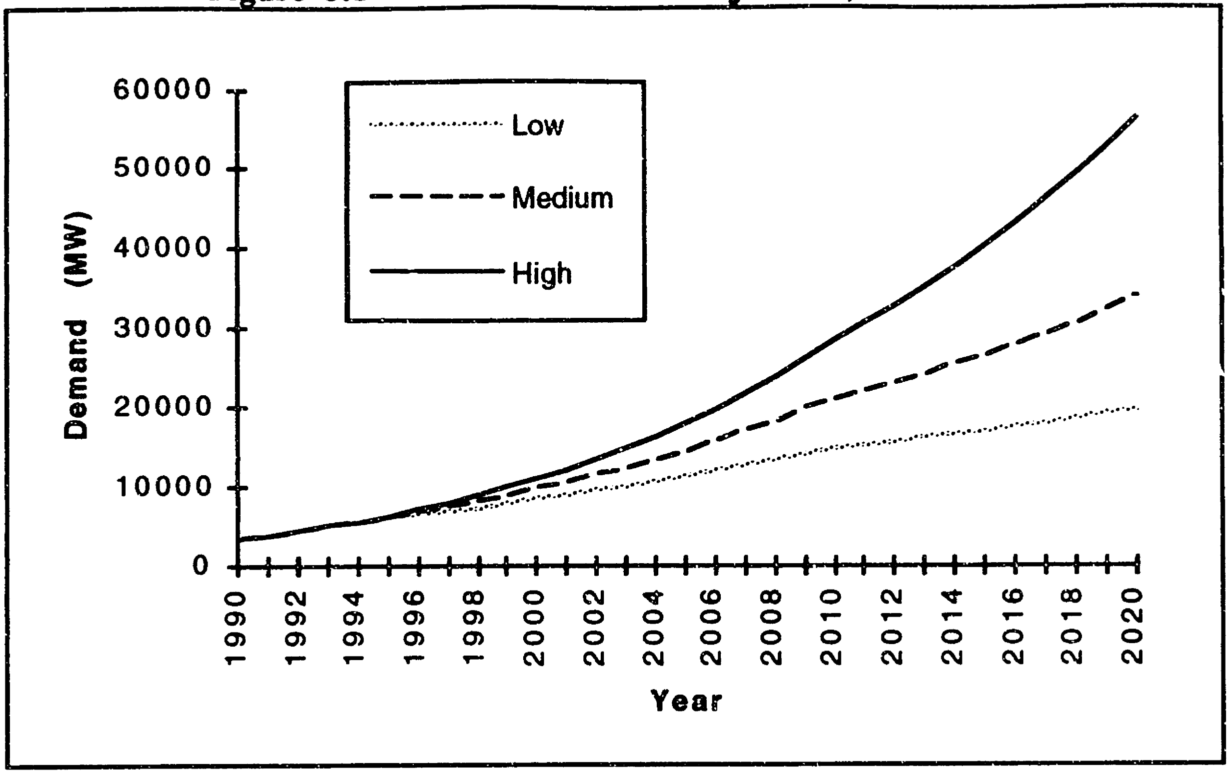
Table 3.5 Forecasted Electricity Demand Growth

Year	Demand Growth		
	Low	Medium	High
1995-2000	7%	10%	12%
2000-2010	6%	8%	10%
2010-2020	3%	5%	7%

Table 3.6 Low, Medium, and High Peak Demand Growth, 1995-2000

Year	Low (MW)	Medium (MW)	High (MW)
1994	5600	5600	5600
1995	5992	6160	6272
1996	6411	6776	7025
1997	6860	7454	7868
1998	7340	8199	8812
1999	7854	9019	9869
2000	8404	9921	11053

Figure 3.1 Demand Growth Projections, 1990-2020



3.4.2 Transmission and Distribution Pricing (N Factor)

At present, transmission and distribution costs for TNB and subsequent prices for transmission of power supplied by the IPPs are calculated by taking the difference between the consumer tariff and the cost of generation for TNB and the profits (return) allowed for TNB. For the last quarter (second quarter 1995), the transmission and distribution price (the N factor) was determined to be 7.91 sen/kWh. However, this methodology for determination of transmission and distribution pricing can quite likely be improved to more accurately reflect cost. This area is generally one that requires further study. Nonetheless, as an initial assumption for this analysis, I have chosen to run a number of base case scenarios with the N factor equaling 8 sen/kWh. Additionally, I have also chosen low and high values for transmission and distribution price of 6 sen/kWh and 10 sen/kWh. It seems apparent that the capital costs for transmission and distribution will increase fairly significantly over the next few years in light of the fairly substantial maintenance required for the existing network and the planned upgrade to 500kV transmission lines to supplement the current grid. TNB is expected to spend more than RM 4 billion by the year 2000 on this expansion to the grid. Again, while the exact implications of this expenditure on the N factor are unclear, it does seem possible that the price would increase.

Additionally, it is important to realize that the N factor is one of the few factors that can directly impact the price contribution of the IPP supply to the overall tariff, as the IPP power purchase terms are fixed over the 21 year period. This will be discussed further at the end of this chapter.

3.4.3 Consumer Price Index (CPI)

The rate of inflation in Malaysia has been low relative to most other countries in the region. The consumer price index rose by less than 1 percent per year between 1985 and 1987 and although the rate of inflation increased after 1987, it has still been contained in the low single digits through the early 1990s. Table 3.7 provides historic information on the CPI increases from 1988 through 1994. It is expected that the government will continue to try to control inflation through tight monetary and fiscal policies which have been successful in recent years.

Table 3.7 Consumer Prices

Year	CPI Increase (%)
1988	2.5
1989	2.8
1990	3.1
1991	4.4
1992	4.7
1993	3.7
1994	3.7

There seems to be considerable confidence in the Malaysian government to keep inflation within its present range. This is quite clearly reflected in the IPP contracts negotiated by Segari, Genting Sanyen, PD Power, and Powertek where rates are subject to increase in inflation only up to a level of 4 percent. An even further extreme example would be YTL who has negotiated its rates with no clause for index to inflation whatsoever.

The base case for analysis uses a constant 4 percent increase in CPI. Additional scenarios with CPI increases of 3, 6, and 8 percent are also analyzed.

3.4.4 Fuel Costs

The primary energy sources used in electricity production are oil, gas, coal and hydro. As was discussed in Chapter 2, an emphasis has been placed on increasing the utilization of natural gas in the power sector in the short term. Beyond the year 2000, it is expected that as oil and gas resources continue to be depleted. Additionally, with the implementation of the Petronas price cap policy on gas usage within the power sector, it is expected that coal will play a more prominent role in the electricity supply mix.

The purchase price of oil within the electricity supply industry is based on the price of medium fuel oil in the Singapore market, reflective of world prices. Gas pricing in Malaysia is determined using the market value based method, where gas prices reflect the price of substitute fuels, namely medium fuel oil. The purchase price for the electricity supply industry represents a 4 percent increase over the Singapore market prices.[76] A slight variation does exist within gas pricing, depending on the location of supply. EPU's policy is to price east coast gas supply cheaper than west coast gas supply due to the ease of access to the pipeline network. Beyond this pricing differential, there is little variation in pricing among TNB and the IPPs.

The coal used in the power sector has primarily been imported from Indonesia and Australia. For the purpose of this thesis, pricing of coal was derived from the import price of coal for Tai Power in Taiwan which also imports coal from Indonesia and Australia.[77]

Table 3.8 Fuel Prices in 1994

Fuel Type	Price (RM/MMBTU)
Oil	6.5
Natural Gas	6.5
Coal	3.5
Hydro	0.0

There is tremendous uncertainty inherent within fuel price projections and historical trends have been fairly inconsistent. In light of this and the general equality in pricing across purchasers, the fuel prices specified in Table 3.8 will be used with little analysis on variations in fuel price.

[76]Personal communication, Mr. Sulaiman, Petronas, July 1995.
[77]Price of coal for Tai Power was extracted from International Energy Agency, *Coal Information 1993*, Paris, 1994.

Oil and gas price variations would impact the final tariff in the same way, irrespective of TNB or IPP supply. Only significant coal price fluctuations could potentially impact the price disproportionately as coal is not currently being utilized by any of the IPPs. Given the historically fairly non-deviant behavior of coal prices and its relatively small contribution to the overall fuel supply mix, this analysis assumes that significant coal price variation impacts need not be considered.

3.4.5 Efficiency of TNB Plants (M factor)

It is a widely held view that until recently, TNB plants and equipment were not well maintained and the general efficiency was quite low. TNB has embarked on several projects to correct this situation and to generally improve maintenance and the overall standard of its plants through rehabilitation and upgrading. It would be expected that this trend will continue especially given the 5 year time frame it has available before it needs to compete again with other IPPs for additional capacity expansion.

The first setting of the M factor which reflects potential for improvement in operations and efficiency was made in late 1993 at 2 percent. This value will be revised again in 1997, and in light of the steps already taken, it is quite likely that this value will decrease at that time. In this analysis, scenarios with an M factor remaining at 2 percent and decreasing to 1 and 0 percent are considered.

3.4.6 Plant Dispatch Levels

The dispatch levels / capacity factors of the various IPP plants indirectly influence the average tariff through their impact on the IPP price per kWh. For purposes of this analysis, the IPP price is determine by aggregating all payments from TNB to the IPPs and subsequently dividing this total payment by the net energy output of all the IPP. (Alternate approaches to calculating IPP_x price are discussed in section 3.5.1)

$$IPP_x = \frac{CP_1 + EP_1 + CP_2 + EP_2 + ... + CP_n + EP_n}{NEO_1 + NEO_2 + ... + NEO_n}$$

While the capacity payment (CP) is not dependent on the capacity factor, both the energy payment (EP) and the net energy output (NEO) values are. If the plant is dispatched at a low level, there will be correspondingly small values for the energy payment and net energy output. On the other hand, the capacity payment will remain constant irrespective of the dispatch level. Hence, the IPP_X value can be crudely seen as having an inverse relationship with the capacity factor.

As presented within section 3.1.2, the grid code specifies that generation units are to be dispatched in accordance with the least variable "operation and maintenance costs inclusive of fuel and consumables" of producing electricity from each generating unit. While the determination of variable O&M costs (here referred to as marginal costs) can be complex when taking into consideration the various load heat rates, the shutdown and startup periods, etc., a fairly reasonable indication of marginal costs can be determined using the simplified calculation as follows:

Marginal cost = Variable costs (exclusive of fuel) + Average Heat Rate * Fuel Cost

Heat rates for the TNB plants were determined based on confidential information obtained as well as approximations obtained using traditional efficiency values for the different plant types and scaling these values accordingly to reflect the plant ages. The variable costs were assumed to be a small fraction of the overall marginal cost, and were estimated at a constant rate of 1.3 sen/ kWh for all thermal plants.[78] Hydro plants were estimated to have variable costs of 2 sen/kWh.[79]

The software package SUTIL[80] was used to model the grid code dispatch requirements and to determine the resultant capacity factors and energy output of the plants. The load duration curve for Malaysia (see figure 3.2), heat rates, variable costs and availability factors for all plants were provided as inputs. Varying scenarios of low, medium and high growth, as specified in Section 3.4.1, were modeled. The resultant capacity factors for the years 1995 through 2000 are presented in Tables 3.9 and 3.10.

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[78]The rate of 1.3 sen/kWh was derived from the variable rates negotiated for the IPP contracts.

[79]A rate of 2 to 3 sen/kWh has been quoted in various sources as average variable costs for hydro projects in Malaysia.

[80]SUTIL is a PC based production-cost model capable of modeling a small power system. It was developed at Princeton University by Professor Henry Kelly. It was modified for use within this analysis by Narasimha Rao at the Union of Concerned Scientists. An example of the use of the model can be found in Johansson, Thomas B., Henry Kelly, Amulya K.N. Reddy and Robert H. Williams, *Renewable Energy: Sources for Fuels and Electricity*, Island Press, 1993.

Figure 3.2 Load Duration Curve for Malaysia

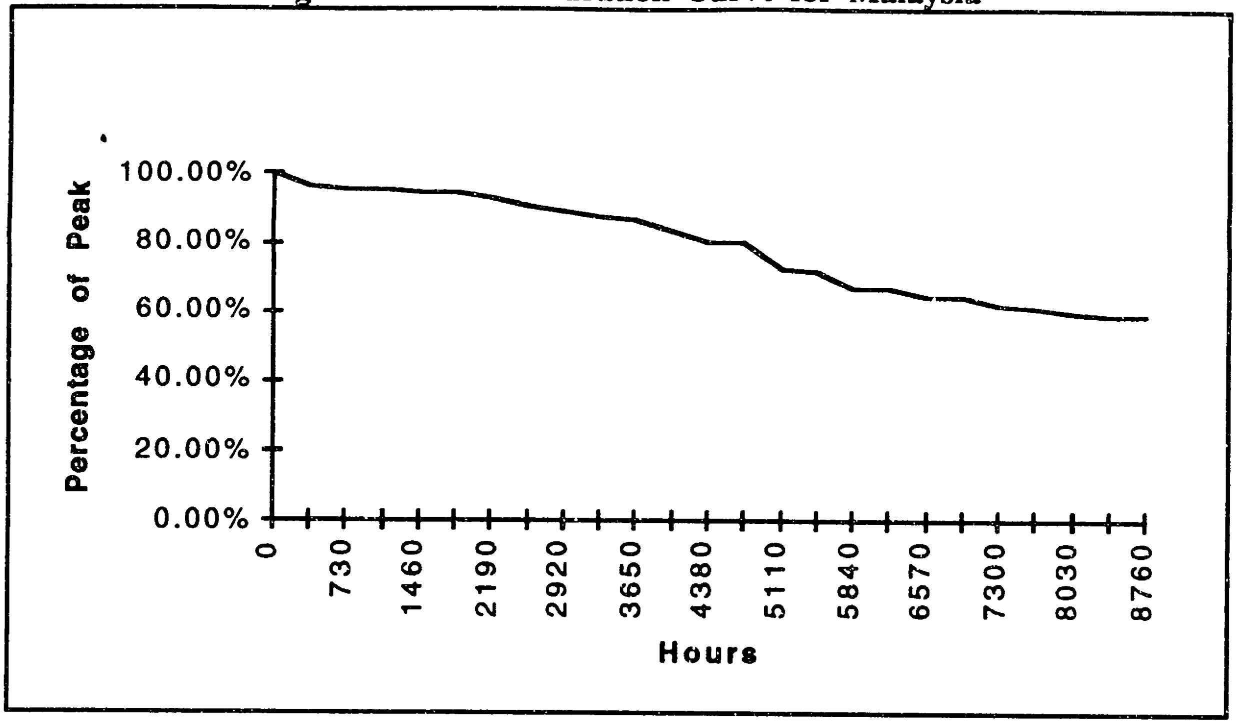

Table 3.9 IPP Capacity Factors, 1995-1997

IPP	1995			1996			1997		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Powertek									
Capacity (MW)	440	440	440	440	440	440	440	440	440
CF	0.00%	60.66%	47.97%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
PD Power									
Capacity (MW)	440	440	440	440	440	440	440	440	440
CF	0.00%	22.46%	53.00%	0.00%	0.00%	0.00%	0.00%	0.00%	0.00%
Segari									
Capacity (MW)	656.5	656.5	656.5	656.5	656.5	656.5	1313	1313	1313
CF	0.00%	0.00%	0.00%	62.92%	71.87%	78.16%	57.51%	68.05%	74.65%
Genting Sanyen									
Capacity (MW)	0	0	0	720	720	720	720	720	720
CF	0.00%	0.00%	0.00%	84.87%	87.01%	87.01%	87.01%	87.01%	87.01%
YTL Paka									
Capacity (MW)	808	808	808	808	808	808	808	808	808
CF	87.00%	87.00%	87.00%	87.00%	86.86%	87.00%	87.00%	87.00%	87.00%
YTL Pasir Gudang									
Capacity (MW)	0	0	0	404	404	404	404	404	404
CF	0.00%	0.00%	0.00%	87.00%	87.00%	87.00%	86.99%	79.08%	86.99%

Table 3.10 IPP Capacity Factors, 1998-2000

	1998			1999			2000		
	Low	Medium	High	Low	Medium	High	Low	Medium	High
Powertek									
Capacity	440	440	440	440	440	440	440	440	440
CF	0.00%	0.00%	0.00%	0.00%	0.40%	2.65%	0.00%	25.28%	40.01%
PD Power									
Capacity	440	440	440	440	440	440	440	440	440
CF	0.00%	0.00%	0.00%	0.00%	5.51%	0.00%	0.00%	33.68%	31.55%
Segari									
Capacity	1313	1313	1313	1313	1313	1313	1313	1313	1313
CF	49.17%	57.84%	67.26%	54.25%	70.53%	81.90%	60.75%	82.39%	86.00%
Genting Sanyen									
Capacity	720	720	720	720	720	720	720	720	720
CF	64.70%	87.01%	87.01%	84.59%	87.01%	87.01%	85.09%	87.01%	87.01%
YTL Paka									
Capacity	808	808	808	808	808	808	808	808	808
CF	87.00%	87.00%	87.00%	87.00%	87.00%	87.00%	87.00%	87.00%	87.00%
YTL Pasir									
Capacity	404	404	404	404	404	404	404	404	404
CF	86.99%	86.99%	86.99%	86.99%	86.99%	87.04%	86.99%	86.99%	86.99%

As can be observed in the tables above, the PD Power and Powertek peaking plants are not dispatched in most cases except when the reserve margin is quite low, as is the case in 1995 for the medium and high growth scenarios and in the year 2000, also in the medium and high demand scenarios. Whether this is likely to be the case in reality is unclear. This situation of zero or low dispatch for some plants is quite possible from 1996 through 1998 as the excess capacity that is projected for these times is very high, with reserve margins in excess of 60 percent. In 1999, as the reserve margin begins to decrease, select peaking plants are increasingly dispatched. It is quite possible that several peaking plants of the same type and costs will be dispatched with low capacity factors in order to evenly distributed the load.

The other three IPP plants, YTL, Segari and Genting Sanyen, essentially serve as baseload plants and for the most part are dispatched close to their maximum availability levels.

In addition to modeling the plants with the capacity factors derived from SUTIL, the tariff impacts on retail rates are also analyzed in the case where the capacity factors are (i) 75 percent for all plants, (ii) 87 percent for all plants, and (iii) 87 percent for baseload plants and 33 percent for peaking plants.[81]

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[81]Some sources have indicated that TNB pays for the PD Power and Powertek peaking plants to be dispatched 8 hours a day regardless of grid code requirements. While there is conflicting information indicating that these

3.5 Scenario Analysis

3.5.1 Pricing Methodologies

As mentioned earlier in section 3.2.2, there is some ambiguity regarding the price to be used as the reference price for TNB prior to inflation (CPI) and efficiency (M factor) adjustments. Included in Appendix A are the results of all simulations using both methodologies, namely referencing simply the TNB portion of price from the previous year, or the overall average tariff from the previous year. To highlight the general difference in results from using the different methodologies, the following (Table 3.11) is an example of the tariff impact in the medium growth scenario with M declining to 1 percent in 1997, with the CPI increase remaining at 4 percent from 1995 to 2000, with the N factor (T&D price) remaining constant as well throughout the period at 8 sen/kWh and with the fuel cost remaining within the benchmark range. Hereafter, this scenario will be referred to as the base case scenario.

Table 3.11 Pricing Methodologies, Base Case Scenario[1]

Year	Total TNB (MW)	Total IPP (MW)	TNB:IPP (ratio)	Total Cap (MW)	A (w/ IPPs) (P=P) aggr	A(w/ IPPs) (P=A) aggr	A (w/ IPPs) (P=P) indiv
1992				0	19.73	19.73	19.73
1993	5975	0	100:0	5975	20.02	20.02	20.02
1994	7465	0	100:0	7465	20.33	20.33	20.33
1995	7535	1690	82:18	9225	21.04	21.04	21.58
1996	7819	3470	69:31	11289	21.96	22.30	undefined
1997	8419	4120	67:33	12539	22.49	23.27	undefined
1998	9419	4120	67:33	13539	22.98	23.87	undefined
1999	9419	4120	70:30	13539	23.55	24.47	103.69
2000	9419	4120	70:30	13539	23.22	24.23	23.77

Notes:
(1) CPI (1996-2000) = 4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh
(2) A (w/ IPPs) (P=P) (aggr) : the average tariff is calculated with P referring to the adjusted TNB contribution to price of the previous year; IPP price is calculated by dividing total energy payments and capacity payments for all IPPs by total energy output for all IPPs; this price is weighted by the IPP percentage of total system capacity
(3) A (w/ IPPs) (P=A) (aggr) : the same as the above except that P refers to the average tariff of the previous year (with both the TNB and IPP contributions included)
(4) A (w/ IPPs) (P=P) (indiv) : the average tariff is calculated with P referring to the TNB portion of the tariff from the previous year; each IPP price is calculated separately and weighted by its capacity percentage of total system capacity; in some cases, when the dispatch level is zero, this number is not defined and in other cases, when the energy output is very low, the price are very high.

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plants are fully dispatchable with no minimum purchase requirements on part of TNB, this provided the impetus to model the last case with 33 percent capacity factor for the peaking plants.

The aggregate pricing methodology determines IPP_X by aggregating all payments from TNB to the IPPs and subsequently dividing this total payment by the net energy output of all the IPP as follows:

$$IPP_X = \frac{(CP_1 + EP_1 + CP_2 + EP_2 + \ldots + CP_n + EP_n)}{(NEO_1 + NEO_2 + \ldots + NEO_n)}$$

While the capacity payment (CP) is not dependent on the capacity factor, both the energy payment (EP) and the net energy output (NEO) values are. If the plant is dispatched at a low level, there will correspondingly be small values for the energy payment and net energy output. On the other hand, the capacity payment will remain constant irrespective of the dispatch level. Hence, the IPP_X value can be crudely seen as having an inverse relationship with the capacity factor.

Within this aggregate IPP price calculation methodology and with P referring to the average tariff from the previous year, the tariff starts off higher than the tariff with P referring to the adjusted TNB portion of the tariff from the previous year. This difference predictably increases over time as the average tariff value in most cases is greater than the TNB price. However, the reverse would be true in the case where the average tariff was less than the TNB price. A drawback that presents itself within this methodology is that all IPP price contributions are weighted equally. This general issue of P determination will be discussed further in the conclusion of this chapter, but for the remainder of this section, P will refer to the TNB adjusted price from the previous year. This is justified by the fact that most of the IPP rates include partial adjustment to CPI.

An alternate approach to calculating IPP_X is to determine the purchase price individually for each IPP. In the case of YTL, this is straightforward as the price is fixed. In the case of the other IPPs with two-part tariff agreements, the purchase price per kWh is determined by simply dividing the total payment (energy and capacity) accorded the IPP by the net energy output produced by the single plant:

$$IPP_X = \frac{CP_X + EP_X}{NEO_X}$$

However, in using this methodology, the values that result can be tremendously varied and these results would be appropriate only if the contributions of generation unit price are weighted by net energy output as opposed to capacity (as is currently specified). The base case medium growth scenario illustrates the disparity of values that can result, ranging from 21.58 sen/kWh to 103.69 sen/kWh, as well as a number of undefined values in the case where there is no net energy output, i.e. the plant is not dispatched at all. As a result of this inconsistency, the discussion of results in the following sections will for the most part, not include this methodology. Nonetheless, the values derived using this methodology have been included in the tables in Appendix A.

It is important to note that TNB payments to the IPPs are unaffected by the choice of pricing methodology. The determination of payments required of the IPPs is very clear and is based on the negotiated rates. The variation instead impacts the level of revenue TNB is able to generate as this directly correlates to the tariff that is charged to the consumers. Generally, with a higher tariff charged, TNB is able to recover greater revenue thus enabling it to earn a higher return. In the case of using the previous year's average tariff (including IPPs) as the present year's reference price, this could work towards leveling the playing field between TNB and the IPPs. However, this would result at the expense of the consumer. Essentially, a tradeoff is required in choosing the appropriate pricing methodology, with either the consumer benefiting in the form of lower tariffs or with TNB benefiting in the form of a higher profit margins (moving closer to those of the IPPs). IPPs are unaffected by this issue.

3.5.2 Demand Growth

The impact of the IPPs can be seen when the first sets come on-line in 1995.[82] This reflects an addition of 1690 MW to the system coming from the baseload plants operated by YTL in Paka, and the two peaking plants owned and operated by PD Power and Powertek. In the medium demand growth scenario, the YTL Paka plant is dispatched at an average capacity factor of 87 percent and the Powertek and PD Power plants are dispatched at an average of 46 percent each. The immediate impact in 1995 (see Table 3.13), assuming that the transmission and distribution price charged remains at 8 sen/kWh, is a 0.71 sen/kWh increase in the average tariff compared with a 0.23 sen/kWh increase that would result had the additional capacity come from TNB. In 1996, a further 0.92 sen/kWh increase would result as compared with a 0.28 sen/kWh increase in the TNB monopoly case. (Had the tariff been derived with the reference price indexed to average tariff, the increase would be significantly greater in 1995 at 1.53 sen/kWh.)

[82]In reality, the plants come on-line in smaller segments, on the scale of individual turbines rather than as one completed unit. Additionall, the units may not be gas-fired immediately and instead some will be diesel-fired for the transition period until the gas access is made available. This will result in larger short-term increases in tariff.

Table 3.12 Reserve margins in the varying demand growth scenarios

Year	Total Capacity (MW)	Low Growth (MW)	Reserve Margin (%)	Medium Growth (MW)	Reserve Margin (%)	High Growth (MW)	Reserve Margin (%)
1995	9225	6048	53	6160	50	6272	47
1996	11289	6471	74	6776	67	7025	61
1997	12539	6924	81	7454	68	7868	59
1998	13539	7409	83	8199	65	8812	54
1999	13539	7928	71	9019	50	9869	37
2000	13539	8483	60	9921	36	11053	22

Table 3.13 Low, Medium, and High Demand Growth Scenarios

			Low	Medium	High
Year	TNB:IPP (Ratio)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)
1992	100:0	19.73	19.73	19.73	19.73
1993	100:0	20.02	20.02	20.02	20.02
1994	100:0	20.33	20.33	20.33	20.33
1995	82:18	20.56	21.61	21.04	20.96
1996	69:31	20.84	22.07	21.96	22.07
1997	67:33	21.26	22.68	22.49	22.38
1998	67:33	21.70	23.42	22.98	22.82
1999	70:30	22.15	23.94	23.55	23.37
2000	70:30	22.62	23.55	23.22	23.14

Notes:
(1) CPI (1996-2000) = 4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh
(2) A (w/o IPPs) : the resultant average tariff for the given year assuming that all capacity additions were done through TNB, with no IPP contracts negotiated.
(3) A (w/ IPPs): the resultant average tariff with P referring to the adjusted TNB contribution to price of the previous year and by using the aggregate pricing methodology (the same approach was used in all scenarios)

The sensitivity to energy output can be observed by comparing the above results to the scenario of low demand growth. In this scenario, with the addition of the IPP capacity of 1690 MW in 1995 and the earlier capacity expansion by TNB in 1994, considerable excess capacity results in 1995, with a reserve margin of 53% (see Table 3.12). Consequently, neither IPP peaking plant is dispatched, and while the TNB payments are correspondingly reduced by approximately RM 300,000 for the year, the average consumer tariff increases 1.28 sen/kWh over the previous year compared again with the 0.23 sen increase that would have resulted from capacity additions through TNB alone.

Similarly, in the case of high demand growth, the peaking plants are dispatched at higher levels averaging 56 percent capacity factor each. Here, the increase in tariff that results in 1995 is only 0.63 sen/kWh. The increase is more substantial in 1996 at 1.01 sen/kWh. This can be explained by the dramatic change in dispatch level of the PD Power and Powertek plants. In 1996, in accordance with the merit-order operation, neither plant is dispatched.

It is important to realize that the correlation that is relevant here is not between demand growth and tariff, but rather dispatch/utilization/capacity level and tariff. For example in 1999, the increases in tariff across the varying demand scenarios are quite comparable, namely 0.52 sen/kWh, 0.57 sen/kWh and 0.55 sen/kWh for the low, medium and high growth scenarios.

In all three demand growth scenarios, the most significant increase in tariff seems to result in the early years, namely 1995 and 1996. Essentially, when the capacity factor payment first kicks in and is accentuated by smaller net energy output levels, the increase is significant. Thereafter, the increases are more modest. In most cases, the tariff decreases in the year 2000. This decrease can be explained in part by the high capacity factors as well as the fact that the TNB portion of the price has increased to levels that are comparably high. Additionally, by the year 2000 or 2001, it is quite likely that the peaking plants will convert from open-cycle operations to combined cycle operations thus reducing their marginal costs and undoubtedly increasing their capacity factors and reducing overall costs per unit.

3.5.3 Transmission and Distribution Prices

As would be expected with a reduction in the value of the transmission and distribution price (N factor), the IPP price contribution reduces, and with an increase in the value of the N factor, the IPP price contribution increases. Slightly more illuminating is the extent of these impacts. In the case where the T&D price is reduced to 6 sen/kWh, the impact is a more modest 0.34 sen/kWh increase in tariff in 1995 and 0.68 sen/kWh increase in 1996, as compared with the 0.71 sen/kWh and 0.92 sen/kWh increases in the case where T&D price is 8 sen/kWh (see Table 3.14). With T&D price raised instead to a rate of 10 sen/kWh, the resulting tariffs in 1995 and 1996 are higher, as would be expected, involving 1.07 sen/kWh and 1.18 sen/kWh increases, respectively.

The N factor has little impact in the later years when the overall capacity share remains constant. In 1999 and 2000 the tariff changes are the same across all three cases.

Table 3.14 Varying Transmission and Distribution (N Factor) Scenarios

				N=6	N=8	N=10
Year	**TNB:IPP (Ratio)**	**Total TNB (MW)**	**Total IPP (MW)**	**A (w/ IPPs) (sen/kWh)**	**A (w/ IPPs) (sen/kWh)**	**A (w/ IPPs) (sen/kWh)**
1992				19.73	19.73	19.73
1993	100:0	5975	0	20.02	20.02	20.02
1994	100:0	7465	0	20.33	20.33	20.33
1995	82:18	7535	1690	20.67	21.04	21.40
1996	69:31	7819	3470	21.35	21.96	22.58
1997	67:33	8419	4120	21.84	22.49	23.15
1998	70:30	9419	4120	22.38	22.98	23.59
1999	70:30	9419	4120	22.95	23.55	24.16
2000	70:30	9419	4120	22.62	23.22	23.83

Notes:
(1) CPI (1996-2000) = 4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh

Basically, the impact of the N factor variation is scaled by the percentage share of IPP generation of overall generation. In the years 1998, 1999 and 2000, the 2 sen/kWh N factor differences result in approximately 0.60 sen/kWh tariff differences across scenarios. In 1995, when the IPPs only constitute 18 percent of the overall supply, the 2 sen/kWh N factor difference produces a corresponding 0.36 sen/kWh tariff difference. This direct consequence is important to understand as it provides for one of the few policy tools that can impact average tariff through affecting the IPP price contribution. It allows for changes in the N factor and/or the generation share between TNB and the IPPs to produce very specific impacts.

Of course, it is also important to bear in mind the direct implication of T&D price fluctuations on TNB profits. TNB is the sole owner and operator of the transmission and distribution grid and is thus responsible for all expenses pertaining to it. These expenditures will be made in advance to plan for forecasted capacity expansion for both TNB and all IPPs; thereafter, if prices are set such that revenues are below the level required to compensate for expenditures and to earn a profit margin, TNB is forced to absorb the losses.

3.5.4 CPI Increase

As was mentioned earlier, the CPI increase value has a direct impact on the TNB portion of the tariff. The full impact of course needs to be addressed by incorporating the M factor. CPI increases also impact the IPP portion of the tariff, although somewhat less directly. In the case where the CPI increase is within the range of 0 and 4 percent, the fixed operating and energy rates are allowed to correspondingly increase when adjusted every 4 years.[83] However, in the situation where the consumer price index rises above a 4 percent annual change, the adjustment for IPP rates is to remain at the ceiling of 4 percent. The capacity rates do not seem to be indexed to inflation at all and this is quite reasonable as fixed costs are by definition incurred up front.

Table 3.15 Varying CPI Increase Scenarios

	CPI = 3		CPI=4		CPI = 6		CPI = 8	
Year	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)
1992	19.73	19.73	19.73	19.73	19.73	19.73	19.73	19.73
1993	20.02	20.02	20.02	20.02	20.02	20.02	20.02	20.02
1994	20.33	20.33	20.33	20.33	20.33	20.33	20.33	20.33
1995	20.56	21.04	20.56	21.04	20.56	21.04	20.56	21.04
1996	20.70	21.84	20.84	21.94	21.11	22.13	21.39	22.32
1997	20.98	22.18	21.26	22.37	21.84	22.75	22.42	23.15
1998	21.26	22.45	21.70	22.75	22.60	23.38	23.53	24.03
1999	21.56	22.90	22.15	23.32	23.39	24.18	24.71	25.10
2000	21.85	22.45	22.62	22.98	24.23	24.11	25.97	25.32

Notes:
(1) CPI (1996-2000) = 4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh
(2) A (w/o IPPs) : the resultant average tariff for the given year assuming that all capacity additions were done through TNB, with no IPP contracts negotiated (TNB monopoly)
(3) A (w/ IPPs): the resultant average tariff with P referring to the adjusted TNB contribution to price of the previous year and by using the aggregate pricing methodology

With increasing levels of CPI increase, the average tariffs increase across all scenarios (see Table 3.15). However, it is important to bear in mind that CPI increases only impact the non-fuel component of price, which in the 1990s, represents approximately 65 percent of the overall tariff. In the case of relatively high inflation with the CPI increase at 8 percent, the average tariff (with IPPs) increases proportionately less each year, with the average tariff in the year 2000 actually being less than the tariff that would have resulted had all capacity expansion been conducted by TNB. With CPI increase at 6 percent, the relative benefit to consumers is lessened, but the break-even point (the point at which the TNB monopoly tariff becomes greater than the TNB/IPP tariff) arrives at the same time, in the year 2000. In the case of CPI increase at or below 4 percent, the differential results are less significant, with average tariff in the TNB/IPP mix consistently greater than the tariff resulting from TNB monopoly.

[80]Most of the analysis done within this thesis, with the exception of this section, was done assuming adjustments for CPI were done annually for both TNB and the IPPs (for all rates). This essentially distributes the increases in tariff price more evenly. A further discussion on this matter will be presented at the end of this chapter.

The CPI increase is perhaps the only factor that poses potential risk for the IPPs. In the case that inflation rises beyond a level of 4 percent, the IPPs are not protected in that adjustments to its variable rates are capped at a ceiling of 4 percent annually. Hence the rate of return earnable by IPPs is fairly vulnerable to significant increases in inflation. While government has been fairly successful in controlling inflation over the past few years and there exists considerable confidence on the part of the independent power participants that the government will continue to maintain this stable macroeconomic situation, the possibility for exposure to risk certainly exists.

3.5.5 Efficiency (M Factor) Variations

As the M factor is adjusted once every 4 years, the first change can be observed only in 1997. With an M factor of 0, the TNB portion of price is allowed to increase with the CPI index. In the case of 4 percent CPI increase and no IPP participation, the entire tariff essentially increases by 2.7 percent (again, the M factor, like the CPI factor, impacts only the non-fuel component of price). With an M factor of 2, the TNB portion of price is maintained at a much lower level and the resulting average tariff is reflective of this, with a 1.35 percent increase in nominal price (see Table 3.16). In the case where capacity expansion is mixed between TNB and IPPs, the increase is mitigated by the IPP portion that is not affected by the M factor. In the case of no IPP participation, the tariff in the year 2000 with an M factor of 2 percent is 1.24 sen/kWh lower than the tariff in the same year with a 0 percent M factor. The tariff difference between the two scenarios with IPP participation is not as extreme but is fairly significant nonetheless, at .86 sen/kWh.

Table 3.16 Varying TNB Efficiency (M factor) Scenarios

	M=2/0%		M=2/1%		M=2/2%	
Year	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)
1992	19.73	19.73	19.73	19.73	19.73	19.73
1993	20.02	20.02	20.02	20.02	20.02	20.02
1994	20.33	20.33	20.33	20.33	20.33	20.33
1995	20.56	21.04	20.56	21.04	20.56	21.04
1996	20.84	21.94	20.84	21.94	20.84	21.94
1997	21.40	22.46	21.26	22.37	21.12	22.27
1998	21.99	22.96	21.70	22.75	21.41	22.55
1999	22.61	23.64	22.15	23.32	21.70	23.01
2000	23.25	23.42	22.62	22.98	22.01	22.56

Notes:
(1) CPI (1996-2000) = 4.0%, N (1993-2000) = 8 sen/kWh
(2) M = 2/0%: from 1993-1996, M factor is set at 2%; from 1997-2000, M factor is set at 0%
(3) M = 2/1%: from 1993-1996, M factor is set at 2%; from 1997-2000, M factor is set at 1%
(4) M = 2/2%: from 1993-2000, M factor is set at 2%
(5) A (w/o IPPs) : the resultant average tariff for the given year assuming that all capacity additions were done through TNB, with no IPP contracts negotiated (TNB monopoly on generation)
(6) A (w/ IPPs): the resultant average tariff with P referring to the adjusted TNB contribution to price of the previous year and by using the aggregate pricing methodology

The M factor essentially lessens the adjustment allowed for CPI changes. In the base case of CPI increase at 4 percent and M factor at 2 percent, this essentially curtails the nominal price increase of the TNB portion of average tariff to 50 percent of the full potential. In essence, this forces the real price down. Accordingly, the M factor has meaning only when treated as being relative to CPI. As it exists, the M factor provides a policy tool for regulating TNB alone. It can provide incentives for improvement in efficiency by penalizing TNB through real price decreases when efficiency and productivity are seen as being sub-optimal. However, upon TNB's improvement in this area, no benefit is passed onto the consumer. All net surplus is borne by TNB. Hence, other tools need to be used in conjunction with this to modify this distribution of surplus.

The impact of the M factor is limited to the TNB portion of the price with no impact on the IPPs, but as the full effect of CPI increase is also applied only to the TNB portion of the price, this is partially justified. This issue of varying factor impact on TNB and the IPPs and the distribution of efficiency gains will be discussed in further detail in the chapter 4.

3.5.6 Capacity Factors

As was mentioned earlier, given the nature of the IPP two-part tariff structure, there exists a direct correlation between plant capacity factor and the resulting IPP price. This can be explained by the significant capacity payment that needs to be made irrespective of the level of dispatch of the plant. To levelize this payment, the higher the energy output, the lower the tariff per kWh.

The low, medium and high growth scenarios that were presented earlier essentially substantiate the claim. In the case of low demand growth and the excess capacity that accompanies it in light of the existing expansion plans, the capacity factors for the IPP plants are comparatively low for the first few years, especially in the case of the peaking plants where they are not dispatched at all throughout the period from 1995 to 2000. Throughout this period, capacity payments are required nonetheless, thus making the marginal cost of IPP power for TNB very high. Based on the tariff control mechanism, this relatively high cost is subsequently passed through to the consumer in the form of higher tariff rates.

Table 3.17 Varying Capacity Factor Scenarios

			Low	Medium	33/75% CF	75% CF	87% CF
Year	TNB:IPP (ratio)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)
1992		19.73	19.73	19.73	19.73	19.73	19.73
1993	100:0	20.02	20.02	20.02	20.02	20.02	20.02
1994	100:0	20.33	20.33	20.33	20.33	20.33	20.33
1995	82:18	20.56	21.61	21.04	21.56	20.82	20.74
1996	69:31	20.84	22.07	21.96	22.61	22.13	21.83
1997	67:33	21.26	22.68	22.49	23.19	22.56	22.20
1998	67:33	21.70	23.42	22.98	23.73	22.87	22.53
1999	70:30	22.15	23.94	23.55	24.47	23.07	22.74
2000	70:30	22.62	23.55	23.22	24.78	23.16	22.86

Notes:
(1) CPI (1996-2000) = 4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh
(2) Low: Capacity factors derived from SUTIL production-cost model based on least variable cost dispatch in the low demand growth scenario
(3) Medium: Capacity factors derived from SUTIL production-cost model based on least variable cost dispatch in the medium demand growth scenario
(4) 33/75% CF: 33% capacity factor for peaking plants (PD Power and Powertek) and 75% capacity factor for baseload plants (YTL, Segari, and Genting Sanyen)
(5) 75% CF: 75% capacity factors for all IPP plants
(6) 87% CF: 87% capacity factors for all IPP plants

In the medium demand growth scenario, the capacity factors are not as low as more power is required and hence more is purchased from the IPPs. This results in correspondingly lower tariffs for the consumers, with differences in tariff between the low and medium growth scenarios varying as much as 1.79 sen/kWh (in 1999) (see Table 3.17).

Additionally, if one examines the scenario of 75 percent capacity factor for the baseload plants and 33 percent capacity factor for the peaking plants (which may indeed reflect the terms of those contracts), then the tariff impact is as shown in Table 3.17. Here the resultant tariffs are higher than in both the low and medium cases as the baseload plants are being used less. In the case where the capacity factors for all plants are at 75 percent, the rates are lower and in the case where the capacity factors are 87 percent (essentially with all plants running at near maximum potential), the rates are close to those that would result if no IPPs were providing power and instead TNB had a monopoly over generation.

Again, it is important to realize that it is only the capacity factor of IPP plants that is directly relevant in this formula. The dispatch level of TNB plants is relevant only in the determination of TNB costs and hence TNB profit, but with no direct consequences for consumer tariff. Additionally, the dispatch levels of IPP plants have direct impacts on the dispatch levels of TNB plant and again, this will impact TNB costs and profits. While no detailed analysis was performed in assessing TNB impacts within the scope of this thesis, this is an area that requires careful consideration.

3.5.7 Negotiated Power Purchase Terms

YTL's terms for power purchase from TNB are significantly different from the terms negotiated by Segari, Genting Sanyen, PD Power and Powertek. As was mentioned earlier, the YTL contract involves a fixed take or pay amount at 75 percent and a levelized tariff rate throughout the 21 year period with no index to inflation. To the contrary, the other 4 IPPs negotiated fairly similar two-part tariffs involving capacity and energy payments. Take or pay terms were not specified and instead the dispatch and power purchase was to be determined by TNB, according to the rules specified within the Grid Code.

The nature of the impacts on average tariff of the two types of contracts can be more clearly observed by analyzing the scenario where all IPP power is supplied through each of the two types of terms. The results of the scenario where all contracts are guaranteed a 75 percent take or pay level and the rate is specified as fixed over the entire 21 year period, are included in Table 3.18. Additionally the scenario with YTL purchase rates specified through the two-part tariff mechanism at Segari's rates are also included in this table.

Table 3.18 Varying Power Purchase Rates and Terms[1]

			orig. terms mixed rates[2]	12.5sen/kWh fixed rate[3]	15.5sen/kWh fixed rate[4]	two-part no take/pay[5]
Year	TNB:IPP (ratio)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)	A (w/ IPPs) (sen/kWh)
1992	100:0	19.73	19.73	19.73	19.73	19.73
1993	100:0	20.02	20.02	20.02	20.02	20.02
1994	100:0	20.33	20.33	20.33	20.33	20.33
1995	82:18	20.56	21.04	20.55	21.1	21.24
1996	69:31	20.84	21.96	20.73	21.65	22.07
1997	67:33	21.26	22.49	21.01	22.00	22.53
1998	67:33	21.70	22.98	21.33	22.25	22.96
1999	70:30	22.15	23.55	21.65	22.56	23.47
2000	70:30	22.62	23.22	21.97	22.89	23.00

Notes:
(1) CPI (1996-2000) = 4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh
(2) orig. terms, mixed rates: base case scenario with rates and terms as specified in negotiated contracts between TNB and the IPPs
(3) 12.5 sen/kWh, fixed rate: hypothetical scenario with fixed rate of 12.5 sen/kWh negotiated for all IPPs
(4) 15.5 sen/kWh, fixed rate: hypothetical scenario with fixed rate of 15.5 sen/kWh negotiated for all IPPs
(5) two-part tariff, no take/pay: scenario with rates and terms as specified in negotiated contracts between TNB and Segari, Genting Sanyen, PD Power and Powertek; YTL modeled with contract terms identical to those of Segari

As can be seen, if all IPP contracts were negotiated with a fixed rate of 12.5 sen/kWh, the resultant average tariffs are the lowest, even slightly lower than the tariffs that would result in the TNB monopoly scenario. With this type of contract, in the long term the rates would remain low and decrease further, relative to the other scenarios including the TNB monopoly one, since there is no index to inflation. However, this is not a very realistic scenario and is simply meant to highlight the contribution of the YTL Paka contract to the overall tariff (namely, in providing a comparatively low cost anchor). In the case where all contracts are fixed but at a rate of 15.5 sen/kWh, the results are also better in the long term, as compared with the present mix (originally specific rates) results. Again, the long term benefits to consumers derive from the absence of inflation adjusters. In the scenario, where all contracts are negotiated through two-part tariff structures, and with the assumption that YTL rates would be set equal to Segari rates, the average tariffs do not differ much from those resulting from the present mix of contracts.

It is difficult to draw conclusions regarding the benefits and disadvantages of the different contracts as they are highly dependent on the specific rates negotiated. There seems to be little consistency thus far in these rates, and hence projections have little basis. The main difference between the two types of contracts arises from the presence or absence of an index to inflation clause. This can have considerable impact, especially in the long term and if inflation is moderate. A secondary impact is with respect to the distribution of the tariff increases. In the case of fixed rates with fairly sizable take or pay terms, the increases in tariff that result are fairly well distributed over time. On the contrary, with the two-part tariff rates, the increase in the first year or two is considerably larger than the increase in subsequent years resulting from the initial impact of the capacity payment, without a corresponding match in energy payment. Additionally, the take or pay terms and the capacity rates have significant impact on TNB payments to the IPPs and its choice of operations with respect to its own generation units.

3.6 Conclusions

As can be seen, there are various parameters that can influence the determination of average tariff to be charged to consumers. As mentioned in the beginning of this chapter, not all of them are flexible and within the control of TNB or the regulator. For example, demand growth is an exogenous variable within the tariff control mechanism. The regulator can do little to control demand growth especially in trying to increase it. On the other hand, should the objective be to limit demand growth, then measures for energy efficiency and conservation can be promoted. However, as was demonstrated in the earlier sections, the objective is really not to influence demand growth per se but the dispatch levels of the existing plants, particularly the IPP units. There are a number of means available in achieving higher dispatch levels. First, IPP plants can be dispatched irrespective of the merit order code, thus making the cost of contracted power less expensive in aggregate. This reduced cost will then be passed onto the consumer in the form of lower average tariffs. Of course in doing so, this forces a very direct consequence for TNB in that some of TNB's plants will remain idle or will be dispatched at lower levels. And this will in turn have direct impacts on TNB operational costs and hence, on TNB profits. While no detailed analysis was done in assessing TNB impacts within the scope of this thesis, it is a consideration that is essential when analyzing regulatory options available. A second option would involve selling more power to neighboring countries so as to reduce the excess capacity that exists in Malaysia. However, this solution will require some time for implementation as the interconnection that currently exists between Malaysia and Thailand and Malaysia and Singapore is fairly limited. Hence, while this approach may be quite appealing, the results may not be seen for the first couple of years. And it is in these first two years or so (1995 and 1996), that the impacts of the contracted power are the greatest.

In addition to dispatch levels, there are other parameters that can be altered to influence the final tariff. The N factor, transmission and distribution price, is one that has very direct implications on the tariff charged to consumers. Again, in the case of this parameter, variance in the value of the N factor will result in a tradeoff between the consumers and TNB. With a lower value for the N factor, the tariff attributed to IPPs (weighted by the IPP generation share) is proportionately reduced. At the same time, the reduction of this price for consumers will have very direct consequences for TNB's ability to sufficiently recover revenues to pay for expenses it has incurred in the construction and maintenance of the transmission and distribution grid. Also, the consistency of pricing for transmission and distribution across the IPPs and TNB needs to be considered. If in effect reducing the N factor implies that the T&D portion of TNB price should also be reduced, this will have even more severe impacts for TNB and its ability to earn a sufficient overall rate of return. Hence, this factor, while certainly providing regulators with a policy tool to influence the average tariff, needs to be used very carefully, and consequences need to be weighed across both the consumers and TNB.

The M factor dictating the potential improvement in efficiency of TNB plants, provides another policy tool that can be used by the regulator to manipulate the average tariff. It can be used to mitigate the tariff increases that would result from adjustment to inflation. In penalizing TNB for poor productivity and efficiency, the consumer is able to reap the benefit in the form of reduced real prices. However, upon implementing efficiency improvement in TNB plants, all subsequent benefits are then borne by TNB. This however, can be corrected by the K factor and this issue will be discussed in chapter 4.

CPI and fuel costs are both exogenous variables. There is little that can be adjusted especially with respect to the TNB portion of the price. There does however exist inequity with respect to how these factors influence the TNB portion of tariff and the IPP portion of tariff. CPI applies to the non-fuel component of TNB price and there seems to exist no ceiling on CPI adjustments. On the contrary, with the IPPs, while there is no direct index to CPI, there does exist an index to inflation within the two-part tariff agreements (4 out of 5 IPPs) for the fixed operating rate and variable operating rates. While there does exist a ceiling to this adjustment of 4 percent annually, it seems that the variable rate which is intended to cover fuel costs, among other things, is allowed to adjust with inflation. Hence, the application of inflation does not seem consistent. Additionally, with the IPP rates, the adjustments are made once every four years as opposed to once a year in the case of TNB. This, however, may slightly alleviate the tariff increases that result in the first few years and may perhaps be a policy consideration as such.

The short term (1995 and 1996) increases in tariff that result in many of the scenarios are generally more significant than those that result in subsequent years (1997 and onwards). The resultant tariffs are between 1 and 2 sen/kWh higher than without IPP participation in the early years and this can be explained by the fairly substantial difference in base price P and the IPP purchase prices. In the long term, the impacts of the previously negotiated IPP contracts are less adverse and the tariffs that result are closer to those that would have resulted in the case of TNB monopoly in generation. As has already been demonstrated, however, the increase in these tariffs will be difficult to implement politically. In the first three quarters after the introduction of the formula, before any of the IPP units came on-line, the average tariff actually decreased as the fuel price fell below the range and a negative pass through was incorporated. When YTL came on line, with the fifth adjustment, the proposed price increase was 0.82 sen/kWh, and the government deemed this unacceptable, especially in light of the elections at the time and the politically sensitive nature of the issue. The tariff formula was essentially suspended. The ramifications of such a suspension remain unclear. As it stands, TNB will still be required to make the capacity payments and the take or pay payments to the IPPs irrespective of the approval of the increase in average tariff, since TNB independently has contracts with the IPPs that it must respect. If the government and regulatory agency disapprove the tariff increase, then TNB is forced to bear the costs, and its profit margin will be compromised. However, the government will no doubt not allow for TNB's performance to suffer tremendously, as it has a considerable stake within TNB itself. Hence, the possibility of tax exemptions, subsidies, and other policy tools will need to be considered especially in the transition period, but with the understanding that overall economic efficiency will be compromised. In this situation, the burden will need to be shared between TNB and the government, if the consumers are not to be 'adversely' impacted. The IPPs are free from bearing any negative consequences as they are protected by their contracts.

Another important point that needs to be emphasized is the ambiguity inherent within certain aspects of the tariff control mechanism. Depending on the interpretation of some of these ambiguities, the resultant impacts can vary quite significantly. For example, if the government were to use 1992 as the base for all price adjustments, and the CPI increase with reference to this base year, the resultant tariffs will involve much greater tariff increases. Additionally, even while choosing the reference year as the previous year, having the TNB portion of price reflect its adjusted price from the previous year or the overall average tariff also results in considerably different outcomes. This ambiguity in and of itself allows the regulator some flexibility with respect to interpretation and subsequent outcomes. However, this ambiguity also provides the possibility for gaming to result within the system, with the players, particularly TNB and JBE, attempting to strategize within the loose framework that exists.

As a final point, in relation to the previous one, this analysis highlights the potential conflict that TNB may face in making decisions as the grid system operator. As a 'competitor' within the generation sector, it may be reasonable for it to make decisions that minimize its costs (which would include payments to IPPs) such that its profits can be maximized. However, in so doing, the implications for overall efficiency may be adversely affected. For example, in minimizing dispatch of IPP plants (possibly while adhering to the dispatch code) and hence minimizing the payment required to the IPPs, the average (and marginal) cost for contracted power becomes much higher and this cost can be passed on the consumers resulting in higher overall tariffs. However, it remains unclear as to whether the regulator will allow for such behavior, through the approval of the tariff, even if it is legitimate within the rules of the existing regulatory framework. If this approval is not guaranteed, then it becomes unclear how TNB would develop business strategies within such an environment. It is also unreasonable to expect TNB decisions to be made with social interests at heart when it has been forced to compete with the IPPs, and on a playing field that is uneven. This issue of inequity in competition will be discussed in the next chapter, along with incentives and disincentives that the present situation provides to TNB and the IPPs.

Chapter 4

Pricing Issues - Regulatory Policy Analysis

"Although developments in the independent power sector have been very promising, many important issues remain to be resolved to ensure that appropriate power supply planning, procurement and regulatory institutions are in place to enable electric utilities to meet their obligations to economically and reliably supply retail customers. The long-term role of the independent power sector, i.e. how utilities can best solicit and contract for power from third parties, how utility-owned and third party generation can be effectively integrated, and how the regulatory process should be adapted to promote all these good things, are all subject to uncertainty and controversy at the present time."[84]

In Chapter 3, the short-term impacts of the existing tariff control mechanism on consumers were analyzed without considering the overall efficacy of the existing pricing policies. In this chapter, the incentives for operational and economic efficiency are examined within existing policies as well as alternate policies. Incentives and implications for TNB and the IPPs under the existing regulatory framework and these alternative approaches are discussed, as well as the resulting implications for consumers in the longer term.

4.1 Rationale Behind Regulation

The regulation of natural monopolies is widely viewed as essential, to ensure socially desirable outcomes when competition cannot be relied upon to achieve them. Regulation essentially replaces the invisible hand of competition with direct intervention.[85] Ideally, regulation should

[84]Paul L. Joskow, 'The Evolution of An Independent Power Sector and Competitive Procurement of New Generating Capacity', *Research in Law and Economics*, Volume 13, 1991, pp 63-100.
[85]Kenneth E. Train, *Optimal Regulation: The Economic Theory of Natural Monopoly*, Cambridge, MIT Press, 1994, pp 317-328.

put pressure on the monopolist so that it performs in price, profit, output and efficiency as if it were in a competitive environment.[86] In the case of public utilities, this direct intervention takes various forms including price fixing, control of profits and revenues, control of entry, prescription of quality and conditions of service and the imposition of an obligation to serve all applicants under reasonable conditions.[87] In the case of private utilities, regulatory bodies replace direct government control through "lighter" regulation, although in many situations, the motivation for regulatory control remains much the same as in the case of public utilities in light of the absence of radical market change and true competition.[88]

In Malaysia, NEB existed as a nationalized natural monopoly up until 1990 and as such government control was implicit. This situation changed considerably post 1990, but it is important to emphasize that while the utility has been privatized and competition has been introduced in the electric power industry, it has been introduced in a very limited form. In the first place, competition is restricted to the generation sector alone. And even within the generation sector, market share remains unevenly distributed, with TNB retaining 70 percent of total market share. Furthermore, only a third of the equity of the privatized utility is owned by the private sector, with the remaining two thirds of equity owned by the government. Additionally, TNB is not a neutral purchaser of generation capacity and regulation needs to address TNB's monopsony status as purchaser of power and its monopoly status as provider of transmission and distribution services. No truly competitive procurement process has been implemented thus far and the government has had very direct involvement in the solicitation and approval of independent participants in the generation sector. Hence competition in its traditional sense is weak at best.

As a consequence, regulatory policy is still very much required to complement the existing competitive structure and to influence private sector behavior in accordance with public interest by establishing an appropriate incentive system to guide or constrain economic decisions. As the customers will not have choice of supplier (with TNB remaining the sole transmitter and distributor of electricity in Peninsula Malaysia), they will be reliant on the regulatory structure to ensure that efficiency gains are passed through to them and that inefficiencies are not.[89] Regulators may also act as "benefactors of last resort" to prevent financial adversity from

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[86] Bernard Tennebnbaum, Reiner Lock and Jim Barker, 'Electricity Privatization: Structural, Competitive and Regulatory Options', *Energy Policy*, Vol 20, No 12, December 1992, pp 1134-1160.
[87] Alfred E. Kahn, *The Economics of Regulation,:Principles and Institutions*, Cambridge, The MIT Press, 1988.
[88] John Winward, 'The Privatization Programme and the Consumer Interest', *Energy Policy*, Vol 17, No 5, October 1989, pp 511-517.
[89] ibid.

compromising a utility's ability to serve. As mentioned earlier, the government maintains a majority share in TNB, and as such has a considerable stake in ensuring that its interests are addressed. This poses potential conflict of interest in the government's role as regulator, and special consideration needs to be taken such that provisions exist for the regulator to have a level of autonomy and independence from other government authorities and TNB, such that overall efficiency is not compromised. In addition to addressing the more detailed issues of pricing, reliability, quality of service, etc., the regulatory framework is also critical in guiding the overall restructuring process that is still very much in flux. Hence, there are many facets of regulation that are still required within the changed industry structure.

Regulation can take many forms. It can directly control the behavior of firms through explicit conduct regulations or it can more indirectly control behavior, through the specification of performance targets.[90] Regulation can theoretically influence a multitude of objectives. It can influence prices, outputs, capital investment, product quality, investment in cost reduction, product innovation and so on.[91] However, in practice, in light of the asymmetry of information that exists between the regulatory agency and the regulated firm and the complexities involved in regulatory policy, regulation can often be directly effective only in a limited number of these objectives. I have chosen to focus on pricing policy and its impacts on a number of these objectives as it is one of the more direct tools available, and one whose use has already been initiated in Malaysia.

In assessing pricing policy and its efficacy, there are several issues that need to be considered, specifically (i) the reflection of the economic cost or true cost of supply in the resultant prices in order to provide efficiency incentives to producers and consumers, and (ii) the generation of sufficient revenues for the sector's development.[92]

4.2 JBE's Regulatory Authority

External regulation of the electric power industry through a dedicated regulatory agency is a fairly new phenomenon in Malaysia, introduced only recently in 1990. Prior to that, all functions, including pricing, planning, safety and licensing, were overseen internally within NEB as it was a government statutory body. The only separation of responsibilities occurred

[90]Tennenbaum et al.
[91]John Vickers and George Yarrow, *Privatization An Economic Analysis*, Cambridge, Cambridge, MIT Press, 1991.
[92]Francis Xavier Jacob, *Privatization and Regulation of the Power Sector in Malaysia*, Kuala Lumpur, JBE, 1994.

in 1983 when the safety and licensing functions were transferred to a separate Electrical Inspectorate.

The regulatory agency's (JBE) mandate, in the form of the 1990 Electricity Act, is to ensure adequacy of present and future supply, economical supply, i.e. production at a reasonable cost, and protection of customers through ensuring reasonable price and quality. JBE's responsibilities also include ensuring safety in the industry, preventing anticompetitive behaviour and checking prudent investment.[93] Additionally, JBE is to concurrently promote the economic development of the country.

It is important to note, however, that several of these requirements were not directly within JBE's control during the early stages of privatization and restructuring. The solicitation and approval of IPP projects and approval of TNB's capacity expansion plans were in large part controlled by the Prime Minister's Department, through the Economic Planning Unit (EPU). JBE's participation was largely peripheral. This has left JBE in an awkward position of incorporating conditions it was not allowed to influence that will perhaps not be consistent with future regulatory strategies. This is already evident in the Grid Code, where exceptions have been made for previously negotiated IPP terms.[94]

4.3 Utility Pricing Policy

4.3.1 Pricing Policy Pre-Privatization

Prior to the introduction of JBE's present pricing policy in 1993, NEB and subsequently TNB fixed tariffs at a level that enabled a return of approximately 6 to 8 percent. This type of rate of return or cost of service regulation was consistent with public utility regulation practice elsewhere throughout the world. Rate of return regulation in Malaysia is essentially equivalent to cost plus pricing where costs are accepted as given, and the consumer tariff is determined by augmenting the underlying cost value by a profit margin based on the specified rate of return. With this type of pricing regulation, NEB was able to earn a level of revenues such that 60 to 65 percent of investment came from internally generated revenues.[95] This self-financing ratio is an important quantitative indicator of the efficacy of the price levels and the financial viability

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[93]Tan Sri Dato Dr. Haji Ani bin Arope, *Progress in Tenaga Nasional After Privatization*, PECC: Private Power in the Pacific, Kuala Lumpur, 23 March 1994.
[94]See Section 1.1.4 of the Malaysian Grid Code, included in the Appendix and in Section 3.1 of Chapter 3.
[95]Personal communication, Ms. Zainab binti Abdullah, TNB, July 1994.

of the utility.[96] It demonstrates that the utility was able to perform reasonably well financially and was not strapped for funds for new investment. The ratio that it was able to achieve was well above the requirements of lending institutions such as the World Bank.[97] Nonetheless, the decision was made to privatize the utility and to introduce competition in the generation sector. This called for the adoption of a new pricing policy suitable for the altered environment.

4.3.2 Pricing Policy Post-Privatization

JBE's pricing policy presently centers around the tariff control mechanism introduced in 1993. As presented in Chapter 3, this mechanism is comprised of two distinct elements. The first part incorporates the CPI-M price formula and applies only to TNB supply. The second element incorporates the previously negotiated IPP purchase prices in conjunction with the transmission and distribution price and additionally allows for fuel cost pass through outside the benchmark fuel price range. The existence of the two distinct parts of the tariff highlight the duality inherent in the regulation applicable to TNB and the IPPs. This apparent inequity will be discussed further in Section 4.5.

4.3.3 Price Cap Regulation

With respect to TNB, the tariff mechanism essentially imposes price cap regulation, with a few deviations. Characteristics traditionally associated with price caps are as follows:
(1) the regulator sets a price, called the price cap, at or below which the regulated firm can set its price; the regulated firm is thus able to retain all profits it earns at this price
(2) regulator may specify that the price cap will be adjusted over time by a preannounced adjustment factor that is exogenous to the firm; for example, the cap may be tied to an index of input prices
(3) at longer intervals, the price cap is reviewed by the regulator and possibly changed; this review is expected to consider the cost, demand and profit conditions of the firm.[98]

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96 Lawrence J. Hill, 'Pricing Initiatives and Development of the Korean Power Sector', *Energy Policy*, Vol 20, No 4, April 1992.
97 The World Bank typically required that 30 to 35 percent of investment be self-financed (personal communication, Ms. Zainab binti Abdullah, TNB, July 1994).
98 See Train, Appendix:Price Caps,*Optimal Regulation*, MIT Press, 1994, pp 317- 328 for a good discussion on the merits and limitations of price caps.

In the case of Malaysia, the regulator (JBE) sets the price cap precisely at the level which will be charged to consumers. TNB is not provided with the option to set price lower than this level. Indeed, TNB is able to retain all profits it earns at this price. Consistent with the above description of price caps, the tariff control in the Malaysian case is subject to annual review based on the exogenous factor, consumer price index. Additionally, on a longer time frame (once every four years), a review is made based on the efficiency of internal operations. It is here that the distortion arises. The Malaysian CPI-M formula is essentially modeled after the RPI-X formula made famous through the British system. In the British system, while RPI is essentially analogous to CPI and represents the retail price index (an index not tied to the company's own costs), the X factor is targeted to the expected net effect of productivity increases, demand growth, and capital expenditures.[99] In the Malaysian case, the M factor is tied only to potential productivity improvements. It is the K factor that incorporates demand growth and overall forecasting errors but this is treated very differently from the M factor in that it is not directly linked to the base level P. Additionally, unlike the M factor, it is subject to adjustment annually.

The K factor as described in JBE publications provides for a correction to the maximum allowed average revenue per unit in the coming year in circumstances where forecasting errors in prior years have led to an actual average revenue per unit which is above or below the maximum allowed in that year under the price formula. As such, the K factor allows for direct control based on revenues and profits, which is contrary to the general principles of price cap regulation. It is possible that the existence of this tool is necessitated by the fact that TNB is not truly a private entity, but one in which the government has a considerable stake. Nonetheless, this factor mitigates the potential benefits of price caps.

The benefits that can be expected from conventional price-cap regulation are as follows:
(1) cost-minimizing strategies including minimizing costs of inputs and processes and investing in cost-effective innovation; such efficient production can be expected since the firm is allowed to retain as profit any cost reductions it achieves
(2) as the regulator reviews the price cap over time, adjustments can be made such that the consumer can also benefit from some of the reduced costs.

While price caps can provide a number of benefits, price cap regulation can also induce potential disadvantages including the following:

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[99]Tennenbaum et al.

(1) in the interim period between reviews, all increased surplus is accrued entirely to the firm, with the consumers not benefiting at all from the production efficiency
(2) the existence of reviews may induce firms to strategically avoid cost reductions such that the resultant adjustments do not reduce the price as dramatically as may have otherwise been the case.[100]

The periodic review is the central issue regarding price caps and the frequency of these reviews and the nature of these reviews can significantly influence utility behavior, utility profits and consumer gains. If the review of the price caps is conducted like the price review under rate-of-return regulation, then the distinction blurs between price-cap regulation and rate-of-return regulation, and most likely, the cost inefficiencies experienced under ROR regulation will continue to persist under price cap regulation. The more frequent the review, the more likely price-cap regulation will induce the inefficiencies of rate-of-return regulation. The less frequent the review, the greater the incentive of the firm to cost-minimize between reviews. In addition to timing of the review, the issue of price cap also rests on what the firm expects the regulator to consider in the subsequent adjustment. Depending on these expectations, the firm may chose to act strategically, contrary to the interests of overall social efficiency.[101]

In Malaysia, the review of price caps is done on varying time scales, depending on the variable to be adjusted. The K factor is adjusted annually, and the M factor is adjusted once every 4 years. Additionally, the fuel cost pass through is adjusted 4 times a year, but this factor has little bearing on the price cap as the costs outside the narrow benchmark fuel cost range are all directly passed through to the consumer. In light of the varying adjustment time frames and the limited experience with this mechanism thus far, the task of assessing TNB's incentives and predicting it's strategic behavior is made more complex. On the one hand, it would seem that TNB would have the incentive to minimize cost and invest in cost-reduction strategies such that it can maximize its profits, especially within the 4 year period before the next M factor adjustment. However, if the regulator were to respond to this improvement in efficiency and productivity with downward price adjustments through reducing the value of the K factor (or making it negative) while concurrently reducing the value of the M factor (an upward price adjustment), then this may result in negligible net benefit for TNB, thus encouraging little improvement. However, if the regulator did not respond in this manner and simply reduced the M factor alone, thus allowing overall nominal price to increase, then the consumer would

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[100]Train.
[101] See Train; for example, prior to the review, the firm may choose not to minimize costs and maximize profits such that the subsequent review will find it inappropriate to reduce the price cap level.

see no benefit from the cost reductions and all surplus would be borne by TNB. This of course suggests that a middle-of-the-road strategy would be optimal where the benefits of improved productivity through reduced costs, etc. are shared by both TNB and the consumer. Unfortunately, regulating such a distribution is much more difficult in practice than in theory. But it is precisely this issue that is critical for regulation to address.

4.3.4 Implementation Issues Under Price Cap Regulation

It is imperative that regulation consider the practical aspects of the incentives that it is providing. Under ROR regulation, price is presumably set above the economically optimal level due to cost inefficiencies. In Malaysia, where regulation was not explicit prior to privatization, there is further reason to believe that costs were likely inflated. On the other hand, there were several benefits that TNB was provided as a government statutory body including tax exemptions, exemptions on import duties, and so on. These essentially served as subsidies and these subsidies were passed on to the consumer through the lower tariffs that resulted. Hence, costs were effectively undervalued in certain cases. While improvement in efficiency is possible with respect to the generation units themselves and the transmission and distribution network, through improved maintenance, conversions and upgrades, it is unclear how these improvements would weigh against increased costs that result from the removal of tax exemptions and other indirect subsidies. Hence the potential for cost reduction remains somewhat ambiguous.

The potential for labour productivity improvement is also unclear. TNB has introduced employee incentive schemes including employee share ownership, and this may provide some positive results with respect to productivity. However, the issue of a bloated labor force or overstaffing is more complex. No involuntary lay-offs have been conducted thus far since the privatization. The Privatization Masterplan explicitly prohibits retrenchment of staff in the privatized enterprise during the first five years. This clause will expire next year and at that time, retrenchment will no doubt still remain a very politically sensitive issue and one that may not be embraced for that reason. Hence, it is important to realize the practical limitations to efficiency and productivity improvements and that implementation of these regulatory approaches may not be as effective as expected.

4.3.5 Impact of Future Regulation

An additional issue that needs to be considered within this form of price cap regulation is the impact of future regulation such as environmental regulation, that may increase the costs of the utility. Will the formula that exists prove sufficient in responding to these potential changes in regulation and the subsequent costs that are incurred? In the case of environmental regulation, it is quite likely that based on the existing mix of plants, TNB will be forced to incorporate much more stringent requirements than the IPPs. All IPP plants that have been proposed thus far are gas-fired and are either presently operating in combined-cycle mode or will convert to combined-cycle within a few years. In all likelihood, it is the coal plants that would be affected by future regulation and possibly some of the older oil-fired plants, as they would be emitting greater concentrations of pollutants.

In contemplating this issue of future changes in regulation, one must again consider the M factor and the K factor. These are the two primary tools available within the existing mechanism that would allow for policy responses to additional cost burdens. It may be reasonable for the K factor to be applied as it essentially serves to respond to higher than expected or lower than expected profits. In the case of higher costs, lower profits would result and hence the K factor value could be increased to allow the utility to recover greater revenue. However, in using the K factor, the regulator would be subscribing to direct profit regulation, contrary to the general principles of price cap regulation. If this were to be avoided, then the M factor would need to be considered. The M factor would need to be carefully calculated to reflect for both production inefficiencies as well as investment needs required to adapt to environmental or other regulation. In using the M factor in this manner, the mechanism would more closely resemble the British RPI-X form. The X factor within this system is not always negative and can be made positive if significant new investment is required.[102] While there are advantages to using the M factor, the disadvantage results from the complexity in its calculation.

4.3.6 Short-Term Projections

The initial price cap set in 1993 was based on the price TNB had charged in 1992 under what was essentially ROR regulation. In light of this, it is possible that TNB will attempt to reduce

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[102]Tenenbaum et al; the Tenenbaum article also mentions an alternate version of the formula with two additional components: a Y factor for unavoidabe costs beyond the control of the company, such as purchase power costs, and a K factor for corrections to ealier predictive errors in the RPI factor. This article refers to Blanche Sas, 'The RPI-X formula: economic regulation in the electricity industry', in International Bar Association, Section on Energy and Natural Resources Law, *Electricity in England and Wales: The Contractual Matrix*, London, 1991.

costs to maximize its profits, at least within the first period prior to adjustments. This would result in increased surplus for TNB, but little pass through in savings to the consumers. However, soon the issue of the timing of price cap reviews will be taken into consideration as will the expectations on the part of TNB. All these considerations are critical in understanding the possible outcomes with respect to operational and economic efficiency and the distribution of surpluses and losses across TNB and the consumers.

4.4 Conduct Regulation and IPP Pricing Policy

Rate of return regulation and price cap regulation are both forms of regulation which focus on outcomes. In the former, the focus is on controlling profits, with little incentive for the regulated utility to operate efficiently. In the latter, the focus is on controlling both price in the immediate sense but also on controlling profits through the periodic review. There is a third option in regulation, namely conduct regulation. This type of regulation focuses on directly controlling a company's behavior as opposed to indirectly controlling it through specifying targets for price, profits, and so on. Conduct regulation can include specifications relevant to competition and the introduction of independent power producers in the electricity supply industry.[103] This in turn can have very direct consequences for pricing of IPP purchases and subsequent treatment of these contracted power costs in retail rate-making.

4.4.1 Regulation and Pricing of Contracted Power Purchases by TNB

In the determination of the purchase price by the utility, direct intervention by the regulator is likely to be counter-productive and inappropriate. The regulator would be in a poor position to assess the information relevant in such a negotiation, as a result of both the inadequate access to information as well as an incomplete understanding of all the risks and financial concerns and constraints involved. On the other hand, specifications of process guidelines, through conduct regulation, with respect to the negotiation process may be very useful. Such conduct regulation can ensure directed socially positive outcomes while not being heavily interventionist and thus allowing the parties some degree of flexibility with respect to securing their individual interests.

There exist three general methods by which utilities can purchase electricity from independent producers. They are as follows:

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[103]Tennenbaum et al.

(1) standard offers from the utility where a price is announced by the utility at which it is willing to buy power under a certain set of conditions; the price is possibly set at the avoided cost of utility

(2) individual negotiation between the utility and the power producer

(3) competitive bidding[104]

The performance of the various approaches to contracted power procurement should be assessed based on a number of objectives. First, incentive for adequate investment in new capacity needs to be provided. Second, the "right kind" of capacity needs be ensured[105], and third, generation based on a least cost basis throughout the year should be achieved.[106]

As mentioned earlier, the Malaysian approach to third-party power purchase thus far consists of a modification of method (2), namely individual negotiation between the utility and the power producer with government intervention and oversight of the negotiation process through the EPU. As such, it is unclear as to what the underlying principles for negotiation were. While there are advantages to this approach in that customized design is possible, there also clear limitations. It seems doubtful that an avoided cost ceiling approach was used in Malaysia as the prices negotiated do not seem to be lower than or equal to the costs of new plants commissioned by TNB. While more than forty proposals were received, with only five approved, it does not seem that the primary criteria for approval was based on purchase price as this was negotiated only after initial approval from the EPU was granted. A continuation of this approach would likely benefit only the IPPs as their prices are essentially capped over a twenty one year period, subject to review only to the exogenous factor, consumer price index. Any benefits gained through increased productivity and improvements in efficiency would be reaped almost entirely by the IPPs except in the case where the resulting load factor of the IPP plant increases thus reducing the average purchase price per kWh. An improvement in this approach could be achieved by removing the explicit government intervention within the negotiation process. The intervention at it currently exists, deters from the securing of an efficient and prudent outcome based on the concerns and interests of the parties directly involved.

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[104]Mel Kilman, 'Competitive Bidding for Independent Power', *Energy Policy*, Vol 22, No 1, January 1994, pp 41-54.
[105]The "right kind" of capacity needs to take into consideration the consistency of fuel choices, plant type choices, locational choices, etc. with broader national objectives and strategies.
[106]Tennenbaum et al.

The standard offer methodology is quite appealing on the basis of improved economic efficiency when compared to the current method. Within this approach, third parties would participate only in the case where their participation is economically sound in that overall costs are either lower than or the same as they would be had TNB continued to own and operated the new facilities. However, the practical difficulty with this approach is in arriving at a value for avoided cost.[107] Additionally, it dampens one of the potentially significant advantages of competition, namely a reduction in the economic rents for the generating entities through further cost reductions (to a level close to actual marginal cost, and below existing utility costs) and subsequent price reductions for consumers.

This approach of avoided cost was taken in the U.S. in the early stages of competition in generation. As a matter of fact, the only specific guidance that existed in the U.S. was that utilities could not be required to purchase at rates that "exceeds the incremental cost to the utility of alternative electric energy". With this specification, the independent producers were not themselves subject to profit or cost of service regulation but effectively subject to price cap regulation defined by the purchasing utility's avoided cost and, as such, the independent's performance depended entirely on its ability to control costs and achieve high levels of plant performance.[108]

The competitive bidding approach also has its merits and its limitations. With excess supply offers, the purchasing utility can filter proposals through competitive bidding to achieve the most advantageous contract and pricing terms. This can be a complex process in light of the multi-dimensions associated with electric power, including level of dispatchability, offer through capacity or energy, location, fuel type and costs, time profile of required payments, financial risks, etc. Care needs to be taken to structure a bidding system that is able to incorporate and rank these various characteristics in a meaningful and efficient manner.[109] The regulatory agency can provide such assistance in clearly articulating standards and making the bidding process fair and transparent through means of conduct regulation.

4.4.2 Treatment of Contracted Power Costs in Retail Rate-Making

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[107]This is difficult for several reasons. First, asymmetry of information would exist between the utility and the regulator; also, many assumptions are required with respect to the future demand and supply situation; additionally, after the avoided cost rule has been in place for a while, it may become "smoke and mirrors" since there is no longer a facility whose cost is being avoided, i.e. difficult to calculate avoided cost of something that never existed.
[108]Tenenbaum et al.
[109]Kilman.

The second issue central to IPP regulation deals with the treatment of the power procurement costs in the determination of final consumer tariffs. As the regulator is responsible for the final approval of tariff change requests by TNB, it would be effective to have the regulator involved in the determination of how the contracted power costs are passed through to the consumer. Currently, the costs of purchase power contracts are essentially treated as pure ringgit-for-ringgit pass-throughs in the determination of the final consumer tariff. However, this type of pure cost-plus system provides little incentive for the utility, TNB, to pick the best mix of contracts (when given the opportunity). This is evident from experience in the U.S. where the costs of purchase power contracts were in theory treated as pure dollar-for-dollar pass-through in the determination of regulated retail rates.[110] On the other hand, given the significant government involvement that presently exists in Malaysia, it would be difficult to implement a system where the purchase price is not directly passed through to the consumer and potential risks of purchase are to be borne by the utility. If government involvement were to be lessened and instead only guidelines on the procurement process were specified, then regulatory review and approval of procured power cost-pass-through may be reasonable. This review and conditional approval would induce the utility to negotiate fairly and wisely, while taking the consumers' interest into consideration.

Given the level of government involvement in the negotiation of power purchases thus far and the limited freedom TNB has had to negotiate its own terms of purchase, it would be unfair to TNB to impose regulation that did not allow full purchased power cost pass-through to the consumers. However, once this government intervention comes to a halt, then the regulation should be designed such that TNB is motivated to pick the best contract and pricing terms. This would include not allowing for automatic approval of direct cost pass-throughs. Either the regulator should be allowed post-negotiation review or the regulator should approve the negotiation process itself.

4.4.3 Dispatching Based on Price vs. Cost

The Merit Order Code within the Grid Code specifies that generating units should be dispatched in accordance with the least variable O&M costs of producing electricity from each generating unit. While this has many merits with respect to overall efficiency, in light of the method for negotiating third-party power contracts thus far, the alternative approach of dispatching based on price may deserve consideration as it would reflect the costs of providing

[110] See discussion in Joskow for more details.

power more accurately. This method would be similar to the U.K. spot market approach where the National Grid Company dispatches generating units on the basis of price offers received for individual generating units. The U.K. approach however differs significantly in that dispatchers are unaware of the variable operating costs and instead attempt to create an optimal pattern of dispatch in every half-hour from the quantities of power that the separate generating companies are willing to offer at specified prices. Additionally, the dispatcher is an independent entity unlike TNB in Malaysia, where TNB may have reason to favour self-supply.

At the present time, there is little incentive for independent producers in Malaysia to negotiate prices that are reflective of marginal cost. But with a move towards increased competition, it is possible that dispatch based on price will result in purchase prices that are closer to marginal cost.

4.4.4 Impact of Future Regulations on IPP Pricing

As was the case when considering pricing policy for TNB, the impact of future regulations that may affect IPP costs need to be considered in assessing regulation for the IPPs. If environmental regulation were to impact independent plants such that their costs of operation are significantly increased, thus reducing their profit margin, how is the regulator to respond to this? Should the IPPs be forced to absorb these cost burdens, and should the regulator only be concerned in the case of threatened financial viability? Within the existing Power Purchase Agreements that have been signed, there exists a built-in security mechanism for the IPPs (and TNB) through the CHANGE-IN-LAW clause:

(1) If there is a Change-in-Law which requires the IPP to make capital improvements or other modifications to the Facility in order to comply with any Law, ... the IPP and TNB shall determine, in good faith, any necessary adjustments to the Capacity Rate Financial to reflect such costs ... [amount of costs and capacity rate financial adjustment require approval of the Department of Electricity Supply]

(2) If there is a Change-in-Law (other than in respect of Taxes) which the IPP or TNB believes in good faith will (i) increase the costs or decrease the revenues of the IPP in connection with the operation or maintenance of the facility, or other conditions affecting the performance by the IPP of its obligations under this Agreement or affecting the timing of the incurrence of such costs or the receipt of such revenues or (ii) decrease the costs or increase the revenues of the IPP ... then the IPP (in case of such increase in costs or decrease in revenues) or TNB (in case of such decrease in costs or increase in revenue) shall determine the amount of such increase or decrease in costs or revenues ... and jointly with the other Party, determine the

applicable adjustments to the Fixed Operating rate and the Variable Operating Rate to reflect such increases or decreases in costs or revenues with the intent that the financial position of the IPP **shall remain unaffected by such Change-in-Law** ... [changes requiring approval of Department of Electricity Supply][111]

In reality, it remains unclear when and how will this clause be executed. No doubt this inherent ambiguity will provide the regulator and the participants flexibility with respect to interpretation. This clause provides for more than adaptation to environmental or other regulations that may impose additional cost burdens. It can have potentially significant ramifications for the IPPs, TNB and the consumers. As efficiency is not directly overseen and regulated by the IPPs through the tariff control mechanism, as is the case for TNB through the M factor, this clause provides the only direct policy tool for the regulator (and TNB) to monitor and subsequently review the terms that have been negotiated between TNB and the IPPs. Again, it is quite possible that politically, it may be a difficult to tool to exploit. But nonetheless, its sheer existence provides additional flexibility to the regulatory mechanism.

4.5 Integrating TNB and IPP Pricing

Based on what has been presented thus far in this chapter, it should be clear that a duality presently exists in JBE's pricing policy for retail rate-making. Different rules and incentives exist for TNB as compared with the IPPs, and this inequity is not conducive to improving the nature of competition and in reaping its full potential benefits. Fairly dramatic changes need to be incorporated if both TNB and the IPPs are to compete fairly for expansion projects, and various regulatory options can be considered that may level the playing field. In considering these options, however, I will continue to emphasize the need to evaluate them in light of overarching government policy objectives as the options have little merit if they conflict with the overall development priorities.

In terms of future regulatory options in this area of pricing, several exist. The first option is to continue in the manner that has already been initiated in Malaysia, essentially involving cost of service/rate of return regulation for TNB and cost pass-through for third party contracts approved by the regulatory agency. Efforts could be taken to improve the price cap mechanism as it applies to TNB. Additionally, the mechanism for procurement of third party power could be modified through one of the approaches described in the previous section. If in fact IPP

[111] Jacob.

supply offers were made within a competitive bidding system, these offers could then act as a yardstick for evaluating TNB proposed projects and for determination of the appropriate adjustments to the price cap. In this approach, the performance of TNB-owned projects would continue to be scrutinized by regulators.

There do exist several alternatives to this general regulatory approach. But consideration of these alternatives needs to be made in light of the overall government objectives, specifically with respect to future capacity expansion. The Ministry of Energy, Telecommunications and Posts has recently made clear the government intentions to keep the TNB/IPP ratio of generating capacity at 70 to 30 percent. This has been espoused on the basis of the government's interest and responsibility in maintaining the positive financial performance of TNB. However, maintaining such a fixed ratio poses a serious limitation to the economic efficiency of the industry as a whole. Additionally, it is important to bear in mind that government policies in this area are by no means engraved in stone as has been witnessed thus far, and hence a consideration of the reversibility or permanency of actions taken is critical in considering alternatives. It is quite possible that the government may gradually reduce its ownership of TNB and in the process, be less interventionist in policies that may affect the performance of TNB.

An alternative to this mixed strategy is the option of pure price cap regulation. In this case, revenues that the utility receives for capacity and energy associated with new generation projects, whether owned by third parties or the utility, are decoupled from the costs that it incurs through contract or ownership. The utility can be compensated for all new generation supplied to it based on values of a power supply index rather than the costs it incurs itself. The utility would be free to adopt any power supply procurement system that it desired, build generation plants itself or purchase from independent suppliers. The only regulatory oversight required would involve ensuring adequacy and reliability of supply. Within this type of system, the utility would have no incentive to favor self-supply over third-party supply unless self-supply is more efficient.[112]

There are some practical limitations with the above concept however. In Malaysia, unlike in the U.S. or other large markets, there is only one utility that serves Peninsula Malaysia. The price index could at most be a composite index based on TNB, SEB and SESCO. This may not provide the adequate diversity and quantity of information required for this mechanism to

[112]Joskow.

be effective. Instead, the price cap may need to be set based on principles currently applied to TNB price cap regulation. And has been discussed in the Section 4.3, there are many complex issues inherent within this approach that would need to be addressed and appropriately resolved.

Alternatively, an integrative bidding approach may be a more viable option for the present time. This approach, which would be a form of conduct regulation, involves bidding for a project not only by the IPPs, but by TNB as well. TNB would potentially offer the first bid, and then review bids by third parties, with regulatory supervision. The regulator would not need to directly review profits or costs. However, this approach does require fairly involved oversight and participation on the part of the regulator as TNB would otherwise have little incentive to select projects from third parties.[113]

4.6 Conclusions

The regulatory framework required to achieve all operational and economic efficiency objectives can be very complex. Additionally complicating the design and execution of regulation is the reality that objectives and priorities vary over time. And as such, it is imperative that regulation be reassessed and reevaluated periodically in light of changing objectives. Regulation also requires time for adoption and adaptation by parties involved and also time for evaluating the performance of the regulation. Unanticipated shortcomings of and constraints to the proposed regulation may present themselves over time, and hence reversibility and flexibility in certain aspects of policy choices and actions also need to be taken into consideration.

Within the context of pricing policy, regulation is multi-faceted as well. As has been shown in this chapter, there are a number of pricing policy tools available. Each of these vary with respect to the type of regulation involved, the incentives for efficiency, and the distribution of benefits between the suppliers and the consumers. As it presently exists, there is a duality in the existing pricing policy towards TNB and the IPPs. While there has existed a certain legitimacy in this duality, it may not be appropriate to maintain this inequity beyond the immediate future. Or at the very least, improvements can be made upon the existing system even if distinct policies are pursued for TNB and the IPPs, through tightening the price cap regulation and introducing competitive procurement in the purchase of third-party power . It is

[113]ibid.

important to understand that the various regulatory options behave differently in response to changes in the macroeconomic situation, changes in the political situation, and changes in external regulations. They also handle distributions of benefits and risks across the participants on the supply side and the consumers, differently.

It is possible that cost-minimization may not have been the primary objective for the first few years of the restructuring process. Instead, more important objectives have perhaps been ensuring that the nationalized utility was transformed into an efficient privatized utility and that a healthy independent power sector was built[114] that is able to provide reliable supply at a "reasonable" cost. While indeed the present approach of individual negotiation and cost-pass-through seems to have satisfactorily achieved the goal of developing the independent power sector, it is imperative to reassess the situation beyond the short-term and focus on the other objectives, including cost-minimization, which the industry as a whole may now be more ready to address.

The objectives of regulation, as stated in the beginning of this chapter, are to promote economic and operational efficiency and to ensure that the benefits of this efficiency are passed onto the consumers. In the short term, I have shown that the current regulatory regime may not be able to achieve these objectives as the policies may result in an unequal distribution of economic rents, and fairly significant tariff increases for the consumer. This in part results from the limited competitive incentives that presently exist. To remedy this situation, in the longer term, it seems reasonable that the playing field in the generation sector be leveled among TNB and the IPPs. As such, the regulatory framework needs to be altered quite drastically. Either a pure price cap regulation or an integrated bidding process could improve the sector performance as measured by the objectives of greater efficiency, higher quality, more innovation and lower prices. The integrated bidding process may offer advantages in that there is less complexity involved with respect to the details of regulation. However, considerable involvement on the part of the regulatory agency will be required to foster fairness and transparency in the bidding process. Most importantly, issues of distribution of benefits from productivity and efficiency improvements need to be addressed such that incentives for improvements continue to exist and that benefits are passed onto the consumers, while ensuring that the financial viability of TNB and the IPPs and the overall health of the industry are not adversely impacted.

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[114]Kilman.

Chapter 5

Conclusions

The corporatization of the electric utility in Malaysia in 1990 marked the beginning of a series of restructuring changes within the sector. More than thirty percent of the utility has now been divested to the private sector. A regulatory agency has been established, along with a new regulatory framework. New players have entered the industry in the generation sector. Power is presently being dispatched by both TNB and these independent power producers. And this transition period is by no means over. Many of the impacts of the changes that have been planned and implemented over the past five years are only now being experienced, and not all of them are positive. Much can be learned from the experience of the past couple of years and from the next couple of years, and the industry structure and regulatory framework should continue to adapt such that the desired objectives and results are achieved.

In assessing the changes thus far, the motivating objectives need to be reevaluated. In Malaysia, the stated objectives of the privatization process of the electric power sector were several. First, efficiency and productivity of the industry were to be improved. Second, competition was to be promoted. Third, the financial and administrative burden of the government was to be relieved. Fourth, the size and presence of the public sector was generally to be reduced. Fifth, to meet the targets of the NEP and NDP, the base of ownership and participation from the public was to be broadened. Last, the privatization was in part targeted to facilitate economic growth.

Have these objectives in fact been achieved? And if not, what factors have presented themselves as impediments to achieving these objectives? With respect to increased efficiency and productivity, the conclusions cannot yet be drawn. The regulatory framework as it presently exists provides ambiguity with respect to incentives for improved efficiency. Depending on the expectations of TNB with respect to regulatory response to improvement in efficiency, these improvements may or may not be achieved in any significance. In the short run, it seems likely that TNB will respond positively in attempting to achieve this objective, but unless the playing field is made more uniform with respect to TNB and the IPPs, this incentive may not persist in the long run.

If promoting competition implies multiple party participation in supply, then in fact competition has been achieved. If competition implies building a healthy independent power sector that is capable of providing reliable supply, then again, this objective can be seen as met since some of these power producers have in fact competently completed construction and begun dispatch of power to TNB. However, if competition implies 'true' competition with participants competing freely and fairly and thus inducing minimal surpluses beyond marginal cost, then in fact, the present environment falls short of this objective. Competition as it exists, is certainly weak at best. TNB maintains dominant market share with dominant government ownership and control, and the independent producers have been far from competing on a least cost basis. Steps can be taken to improve the competitive process among IPPs when they are next solicited, but additionally, the regulation needs to incorporate a fair and transparent process whereby TNB and the IPPs together can participate in a competitive environment, thus producing the favorable outcomes of competition including cost-minimization.

With respect to the objective of relieving the financial and administrative burden of the government, this has been achieved in part. The financial burden has certainly been relieved through the participation of the independent players. Two thirds of the capacity expansion conducted from 1994 through 1999 was done through these independent players and most of their financing was done successfully domestically, without any assistance from local or foreign governments, or multilateral lending institutions. With respect to alleviating the administrative burden of the government, the experience thus far has been dubious. There has been considerable government involvement in the solicitation, approval, and negotiation of the independent power proposals and contracts. The transition period has been complicated in dealing with the transfer of certain responsibilities, etc. and certain activities have been performed redundantly by government agencies among others. It is quite likely that this situation will improve and correct itself over the next few years, but concerted effort needs to be taken to alter the competitive procurement process, such that the process is more transparent and void of active government intervention. This will in turn alleviate the administrative burden on the government.

It is quite clear that through the privatization and restructuring process of the power sector, the size and presence of the public sector has been reduced. However, strict limits have been imposed on this reduction in size. The government has thus far advocated leaving transmission and distribution within the monopoly control of TNB and limiting private sector participation to 30 percent of the generation sector. In so doing, it is restricting the potential efficiency gains that can be achieved and the competitive market for working freely.

Ownership and participation from the public has been carefully broadened. It is widely known that the IPP proposals that were accepted in part on the basis of political connections. Bumiputera participation was implicit within all these proposals and in some cases, explicitly solicited by the EPU. As such, targets of the NEP and the NDP have been consistently met.

The privatization process can be seen as meeting the objective of facilitating economic growth. It has done so by maintaining discounts for industrial consumers and continuing the cross subsidies by charging higher rates to residential consumers. However, the process as has been conducted thus far should theoretically result in higher average tariffs simply based on the terms that have been negotiated and the existing regulatory pricing mechanism. The government however has chosen not to support these tariff increases for fear of adverse political reactions, and possibly adverse economic reactions. This, however, induces additional inefficiencies in the system as compensating policies need to implemented to allow for this inadmission of price pass-through to consumers. Pricing aside, through the rapid capacity expansion that has been planned and initiated, the previously existing supply constraints should essentially be eliminated thus making the rapid electricity demand growth manageable. Additionally, through financing all independent power projects domestically, the absorptive capacity of domestic capital market has also been improved, contributing to overall economic growth of the country.

In assessing the achievement of stated objectives, it becomes evident that the interests of consumers and the impacts of the privatization and restructuring process on consumers were initially largely ignored. The incidental impact of the reform on consumers remains somewhat ambiguous with respect to the tariffs they are charged. But the analysis within this thesis has demonstrated that these impacts can be adverse in the short-term. The degree of this impact is very much dependent on the interpretation of the present regulation, and the utilization of available policy tools over the next few years. As the regulatory and competitive environment has evolved thus far, there exists considerable room for flexibility with respect to the distribution of economic rents, benefits of efficiency, and costs of inefficiency. This flexibility, while potentially an asset in the short term with respect to policy making, needs to be limited in the long term. Continued reforms within the regulatory framework are required to ensure that the potential benefits of competition a changed industry structure are achieved, in a socially efficient manner.

Appendix A

Scenario Analysis

The following tables summarize the results of the various scenario analyses that were performed. The first table, Table A.1, provides information on the system capacities for the years 1993 through 2000. This information is applicable to all subsequent tables.

Table A.1 System Capacity, 1993 - 2000

Year	TNB Capacity Addition (MW)	Total TNB Capacity (MW)	IPP Capacity Addition (MW)	Total IPP Capacity (MW)	TNB:IPP (Ratio)	Total Capacity (MW)
1992						
1993	0	5975	0	0	100:0	5975
1994	1490	7465	0	0	100:0	7465
1995	70	7535	1690	1690	82:18	9225
1996	284	7819	1780	3470	69:31	11289
1997	600	8419	650	4120	67:33	12539
1998	1000	9419	0	4120	70:30	13539
1999	0	9419	0	4120	70:30	13539
2000	0	9419	0	4120	70:30	13539

Clarification of notation used in following tables:

(1) A (w/o IPPs) : the resultant average tariff for the given year assuming that all capacity additions were done through TNB, with no IPP contracts negotiated (hypothetical situation)

(2) A (w/ IPPs) (P=P) (aggr) : the average tariff is calculated with P referring to the adjusted TNB contribution to price of the previous year, *(P*(1+(CPI-M)/100)+Y))*; IPP price is calculated by dividing total energy payments and capacity payments for all IPPs by total energy output for all IPPs; this price is weighted by the IPP percentage of total system capacity

(3) A (w/ IPPs) (P=A) (aggr) : the same as the above (2) except that P refers to the average tariff of the previous year (with both the TNB and IPP contributions included)

(4) A (w/ IPPs) (P=P) (indiv) : the average tariff is calculated with P referring to the adjusted TNB portion of the tariff from the previous year; each IPP price is calculated separately and weighted by its percentage of total system capacity; in some cases, when the dispatch level is zero, this number is undefined and in other cases, when the energy output is very low, the price are very high.

Table A.2 Medium Growth, Base Case Scenario[1]

Year	CPI	M	N	Y	A (w/o IPPs)	A (w/ IPPs)		
	(%)	(%)	(sen)	(sen)	(sen/kWh)	(P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	4.00	2	8	6.65	20.84	21.96	22.30	undefined
1997	4.00	1	8	6.65	21.26	22.49	23.27	undefined
1998	4.00	1	8	6.65	21.70	22.98	23.87	undefined
1999	4.00	1	8	6.65	22.15	23.55	24.47	103.69
2000	4.00	1	8	6.65	22.62	23.22	24.23	23.77

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh

Table A.3 Medium Growth

Year	CPI	M	N	Y	A (w/o IPPs)	A (w/ IPPs)		
	(%)	(%)	(sen)	(sen)	(sen/kWh)	(P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	6.00	2	8	6.65	21.11	22.15	22.50	undefined
1997	6.00	1	8	6.65	21.84	22.88	23.61	undefined
1998	6.00	1	8	6.65	22.60	23.61	24.37	undefined
1999	6.00	1	8	6.65	23.39	24.42	25.16	104.55
2000	6.00	1	8	6.65	24.23	24.35	25.10	24.90

Notes: CPI (1996-2000)=6.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh

Table A.4 Medium Growth

Year	CPI	M	N	Y	A (w/o IPPs)	A (w/ IPPs)		
	(%)	(%)	(sen)	(sen)	(sen/kWh)	(P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	3.00	2	8	6.65	20.70	21.87	22.20	undefined
1997	3.00	1	8	6.65	20.98	22.30	23.10	undefined
1998	3.00	1	8	6.65	21.26	22.68	23.62	undefined
1999	3.00	1	8	6.65	21.56	23.14	24.15	103.28
2000	3.00	1	8	6.65	21.85	22.69	23.82	23.24

Notes: CPI (1996-2000)=3.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh

Table A.6 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	10.00	2	8	6.65	21.67	22.54	22.90	undefined
1997	10.00	1	8	6.65	23.02	23.67	24.31	undefined
1998	10.00	1	8	6.65	24.50	24.93	25.42	undefined
1999	10.00	1	8	6.65	26.10	26.30	26.63	106.44
2000	10.00	1	8	6.65	27.85	26.87	27.02	27.41

Notes: CPI (1996-2000)=10.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1993-2000) = 8 sen/kWh

Table A.7 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	20.67	20.67	21.21
1996	4.00	2	6	6.65	20.84	21.35	21.43	undefined
1997	4.00	1	6	6.65	21.26	21.84	22.19	undefined
1998	4.00	1	6	6.65	21.70	22.38	22.79	undefined
1999	4.00	1	6	6.65	22.15	22.95	23.43	103.08
2000	4.00	1	6	6.65	22.62	22.62	23.19	23.16

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 6 sen/kWh

Table A.8 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.40	21.40	21.94
1996	4.00	2	10	6.65	20.84	22.58	23.17	undefined
1997	4.00	1	10	6.65	21.26	23.15	24.35	undefined
1998	4.00	1	10	6.65	21.70	23.59	24.95	undefined
1999	4.00	1	10	6.65	22.15	24.16	25.52	104.30
2000	4.00	1	10	6.65	22.62	23.83	25.27	24.38

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 10 sen/kWh

Table A.9 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	4.00	2	8	6.65	20.84	21.96	22.30	undefined
1997	4.00	0	8	6.65	21.40	22.59	23.37	undefined
1998	4.00	0	8	6.65	21.99	23.19	24.05	undefined
1999	4.00	0	8	6.65	22.61	23.87	24.74	104.01
2000	4.00	0	8	6.65	23.25	23.66	24.58	24.21

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 8 sen/kWh

Table A.10 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	20.67	20.67	21.21
1996	4.00	2	6	6.65	20.84	21.35	21.43	undefined
1997	4.00	0	6	6.65	21.40	21.93	22.29	undefined
1998	4.00	0	6	6.65	21.99	22.58	22.96	undefined
1999	4.00	0	6	6.65	22.61	23.26	23.69	103.40
2000	4.00	0	6	6.65	23.25	23.05	23.53	23.60

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 6 sen/kWh

Table A.11 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.40	21.40	21.94
1996	4.00	2	10	6.65	20.84	22.58	23.17	undefined
1997	4.00	0	10	6.65	21.40	23.24	24.46	undefined
1998	4.00	0	10	6.65	21.99	23.80	25.13	undefined
1999	4.00	0	10	6.65	22.61	24.48	25.78	104.62
2000	4.00	0	10	6.65	23.25	24.27	25.63	24.82

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 10 sen/kWh

Table A.12 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	4.00	2	8	6.65	20.84	21.96	22.30	undefined
1997	4.00	2	8	6.65	21.12	22.40	23.17	undefined
1998	4.00	2	8	6.65	21.41	22.78	23.69	undefined
1999	4.00	2	8	6.65	21.70	23.24	24.22	103.38
2000	4.00	2	8	6.65	22.01	22.80	23.89	23.35

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 8 sen/kWh

Table A.13 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.40	21.40	21.94
1996	4.00	2	10	6.65	20.84	22.58	23.17	undefined
1997	4.00	2	10	6.65	21.12	23.05	24.25	undefined
1998	4.00	2	10	6.65	21.41	23.39	24.76	undefined
1999	4.00	2	10	6.65	21.70	23.85	25.26	103.99
2000	4.00	2	10	6.65	22.01	23.41	24.93	23.96

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 10 sen/kWh

Table A.14 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	20.67	20.67	21.21
1996	4.00	2	6	6.65	20.84	21.35	21.43	undefined
1997	4.00	2	6	6.65	21.12	21.74	22.09	undefined
1998	4.00	2	6	6.65	21.41	22.17	22.61	undefined
1999	4.00	2	6	6.65	21.70	22.63	23.18	102.77
2000	4.00	2	6	6.65	22.01	22.19	22.85	22.74

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 6 sen/kWh

Table A.15 Medium Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.04	21.04	21.58
1996	4.00	2	8	6.65	20.84	21.96	22.30	undefined
1997	4.00	3	8	6.65	20.98	22.30	23.07	undefined
1998	4.00	3	8	6.65	21.12	22.58	23.51	undefined
1999	4.00	3	8	6.65	21.27	22.94	23.96	103.07
2000	4.00	3	8	6.65	21.41	22.39	23.56	22.93

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 3%, N (1995-2000) = 8 sen/kWh

Table A.16 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.61	21.61	undefined
1996	4.00	2	8	6.65	20.84	22.07	22.81	undefined
1997	4.00	1	8	6.65	21.26	22.68	23.54	undefined
1998	4.00	1	8	6.65	21.70	23.42	24.44	undefined
1999	4.00	1	8	6.65	22.15	23.94	25.17	undefined
2000	4.00	1	8	6.65	22.62	23.55	24.83	24.13

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.17 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.61	21.61	undefined
1996	6.00	2	8	6.65	21.11	22.26	23.02	undefined
1997	6.00	1	8	6.65	21.84	23.07	23.88	undefined
1998	6.00	1	8	6.65	22.60	24.04	24.94	undefined
1999	6.00	1	8	6.65	23.39	24.80	25.86	undefined
2000	6.00	1	8	6.65	24.23	24.67	25.70	25.25

Notes: CPI (1996-2000)=6.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.18 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.61	21.61	undefined
1996	3.00	2	8	6.65	20.70	21.97	22.71	undefined
1997	3.00	1	8	6.65	20.98	22.49	23.37	undefined
1998	3.00	1	8	6.65	21.26	23.11	24.19	undefined
1999	3.00	1	8	6.65	21.56	23.52	24.84	undefined
2000	3.00	1	8	6.65	21.85	23.02	24.41	23.60

Notes: CPI (1996-2000)=3.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.19 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.61	21.61	undefined
1996	10.00	2	8	6.65	21.67	22.65	23.44	undefined
1997	10.00	1	8	6.65	23.02	23.87	24.58	undefined
1998	10.00	1	8	6.65	24.50	25.36	26.00	undefined
1999	10.00	1	8	6.65	26.10	26.69	27.34	undefined
2000	10.00	1	8	6.65	27.85	27.19	27.63	27.77

Notes: CPI (1996-2000)=10.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.20 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	21.25	21.25	undefined
1996	4.00	2	6	6.65	20.84	21.45	21.94	undefined
1997	4.00	1	6	6.65	21.26	22.03	22.45	undefined
1998	4.00	1	6	6.65	21.70	22.81	23.36	undefined
1999	4.00	1	6	6.65	22.15	23.33	24.12	undefined
2000	4.00	1	6	6.65	22.62	22.94	23.78	23.52

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 6 sen/kWh

Table A.21 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.98	21.98	undefined
1996	4.00	2	10	6.65	20.84	22.68	23.69	undefined
1997	4.00	1	10	6.65	21.26	23.34	24.62	undefined
1998	4.00	1	10	6.65	21.70	24.02	25.51	undefined
1999	4.00	1	10	6.65	22.15	24.55	26.21	undefined
2000	4.00	1	10	6.65	22.62	24.16	25.87	24.74

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 10 sen/kWh

Table A.22 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.61	21.61	undefined
1996	4.00	2	8	6.65	20.84	22.07	22.81	undefined
1997	4.00	0	8	6.65	21.40	22.78	23.64	undefined
1998	4.00	0	8	6.65	21.99	23.62	24.62	undefined
1999	4.00	0	8	6.65	22.61	24.26	25.43	undefined
2000	4.00	0	8	6.65	23.25	23.98	25.18	24.57

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 8 sen/kWh

Table A.23 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	21.25	21.25	undefined
1996	4.00	2	6	6.65	20.84	21.45	21.94	undefined
1997	4.00	0	6	6.65	21.40	22.12	22.55	undefined
1998	4.00	0	6	6.65	21.99	23.01	23.53	undefined
1999	4.00	0	6	6.65	22.61	23.65	24.38	undefined
2000	4.00	0	6	6.65	23.25	23.38	24.13	23.96

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 6 sen/kWh

Table A.24 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.98	21.98	undefined
1996	4.00	2	10	6.65	20.84	22.68	23.69	undefined
1997	4.00	0	10	6.65	21.40	23.44	24.73	undefined
1998	4.00	0	10	6.65	21.99	24.23	25.70	undefined
1999	4.00	0	10	6.65	22.61	24.86	26.48	undefined
2000	4.00	0	10	6.65	23.25	24.59	26.23	25.17

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 10 sen/kWh

Table A.25 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.61	21.61	undefined
1996	4.00	2	8	6.65	20.84	22.07	22.81	undefined
1997	4.00	2	8	6.65	21.12	22.59	23.43	undefined
1998	4.00	2	8	6.65	21.41	23.21	24.26	undefined
1999	4.00	2	8	6.65	21.70	23.63	24.91	undefined
2000	4.00	2	8	6.65	22.01	23.12	24.49	23.70

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 8 sen/kWh

Table A.26 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	21.25	21.25	undefined
1996	4.00	2	6	6.65	20.84	21.45	21.94	undefined
1997	4.00	2	6	6.65	21.12	21.93	22.36	undefined
1998	4.00	2	6	6.65	21.41	22.61	23.18	undefined
1999	4.00	2	6	6.65	21.70	23.02	23.87	undefined
2000	4.00	2	6	6.65	22.01	22.51	23.45	23.09

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 6 sen/kWh

Table A.27 Low Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.98	21.98	undefined
1996	4.00	2	10	6.65	20.84	22.68	23.69	undefined
1997	4.00	2	10	6.65	21.12	23.25	24.51	undefined
1998	4.00	2	10	6.65	21.41	23.82	25.33	undefined
1999	4.00	2	10	6.65	21.70	24.24	25.95	undefined
2000	4.00	2	10	6.65	22.01	23.73	25.53	24.31

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 10 sen/kWh

Table A.28 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	4.00	2	8	6.65	20.84	22.07	22.35	undefined
1997	4.00	1	8	6.65	21.26	22.38	23.24	undefined
1998	4.00	1	8	6.65	21.70	22.82	23.62	undefined
1999	4.00	1	8	6.65	22.15	23.37	24.18	undefined
2000	4.00	1	8	6.65	22.62	23.14	24.02	23.50

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.29 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	3.00	2	8	6.65	20.70	21.97	22.26	undefined
1997	3.00	1	8	6.65	20.98	22.19	23.07	undefined
1998	3.00	1	8	6.65	21.26	22.52	23.38	undefined
1999	3.00	1	8	6.65	21.56	22.96	23.85	undefined
2000	3.00	1	8	6.65	21.85	22.61	23.61	22.97

Notes: CPI (1996-2000)=3.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.30 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	6.00	2	8	6.65	21.11	22.26	22.55	undefined
1997	6.00	1	8	6.65	21.84	22.77	23.58	undefined
1998	6.00	1	8	6.65	22.60	23.45	24.13	undefined
1999	6.00	1	8	6.65	23.39	24.24	24.86	undefined
2000	6.00	1	8	6.65	24.23	24.26	24.88	24.62

Notes: CPI (1996-2000)=6.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.31 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	10.00	2	8	6.65	21.67	22.65	22.95	undefined
1997	10.00	1	8	6.65	23.02	23.56	24.28	undefined
1998	10.00	1	8	6.65	24.50	24.77	25.18	undefined
1999	10.00	1	8	6.65	26.10	26.12	26.33	undefined
2000	10.00	1	8	6.65	27.85	26.78	26.80	27.14

Notes: CPI (1996-2000)=10.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.32 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	8.00	2	8	6.65	21.39	22.45	22.75	undefined
1997	8.00	1	8	6.65	22.42	23.16	23.93	undefined
1998	8.00	1	8	6.65	23.53	24.09	24.64	undefined
1999	8.00	1	8	6.65	24.71	25.15	25.57	undefined
2000	8.00	1	8	6.65	25.97	25.48	25.81	25.84

Notes: CPI (1996-2000)=6.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.33 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	20.59	20.59	20.74
1996	4.00	2	6	6.65	20.84	21.45	21.48	undefined
1997	4.00	1	6	6.65	21.26	21.73	22.15	undefined
1998	4.00	1	6	6.65	21.70	22.21	22.55	undefined
1999	4.00	1	6	6.65	22.15	22.77	23.13	undefined
2000	4.00	1	6	6.65	22.62	22.53	22.97	22.89

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 6 sen/kWh

Table A.34 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.33	21.33	21.47
1996	4.00	2	10	6.65	20.84	22.68	23.23	undefined
1997	4.00	1	10	6.65	21.26	23.04	24.32	undefined
1998	4.00	1	10	6.65	21.70	23.43	24.70	undefined
1999	4.00	1	10	6.65	22.15	23.98	25.22	undefined
2000	4.00	1	10	6.65	22.62	23.75	25.06	24.11

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 10 sen/kWh

Table A.35 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	4.00	2	8	6.65	20.84	22.07	22.35	undefined
1997	4.00	2	8	6.65	21.12	22.29	23.13	undefined
1998	4.00	2	8	6.65	21.41	22.62	23.45	undefined
1999	4.00	2	8	6.65	21.70	23.06	23.92	undefined
2000	4.00	2	8	6.65	22.01	22.72	23.68	23.07

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 8 sen/kWh

Table A.36 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.33	21.33	21.47
1996	4.00	2	10	6.65	20.84	22.68	23.23	undefined
1997	4.00	2	10	6.65	21.12	22.94	24.21	undefined
1998	4.00	2	10	6.65	21.41	23.23	24.52	undefined
1999	4.00	2	10	6.65	21.70	23.67	24.96	undefined
2000	4.00	2	10	6.65	22.01	23.32	24.72	23.68

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 10 sen/kWh

Table A.37 High Growth

Year	CPI	M	N	Y	A (w/o IPPs)	A (w/ IPPs)		
	(%)	(%)	(sen)	(sen)	(sen/kWh)	(P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	20.59	20.59	20.74
1996	4.00	2	6	6.65	20.84	21.45	21.48	undefined
1997	4.00	2	6	6.65	21.12	21.63	22.05	undefined
1998	4.00	2	6	6.65	21.41	22.01	22.37	undefined
1999	4.00	2	6	6.65	21.70	22.45	22.88	undefined
2000	4.00	2	6	6.65	22.01	22.11	22.64	22.47

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 2%, N (1995-2000) = 6 sen/kWh

Table A.38 High Growth

Year	CPI	M	N	Y	A (w/o IPPs)	A (w/ IPPs)		
	(%)	(%)	(sen)	(sen)	(sen/kWh)	(P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.96	20.96	21.10
1996	4.00	2	8	6.65	20.84	22.07	22.35	undefined
1997	4.00	0	8	6.65	21.40	22.48	23.34	undefined
1998	4.00	0	8	6.65	21.99	23.03	23.80	undefined
1999	4.00	0	8	6.65	22.61	23.69	24.44	undefined
2000	4.00	0	8	6.65	23.25	23.58	24.36	23.94

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 8 sen/kWh

Table A.39 High Growth

Year	CPI	M	N	Y	A (w/o IPPs)	A (w/ IPPs)		
	(%)	(%)	(sen)	(sen)	(sen/kWh)	(P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	10	6.65	20.56	21.33	21.33	21.47
1996	4.00	2	10	6.65	20.84	22.68	23.23	undefined
1997	4.00	0	10	6.65	21.40	23.14	24.43	undefined
1998	4.00	0	10	6.65	21.99	23.63	24.89	undefined
1999	4.00	0	10	6.65	22.61	24.30	25.49	undefined
2000	4.00	0	10	6.65	23.25	24.19	25.41	24.55

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 10 sen/kWh

Table A.40 High Growth

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	6	6.65	20.56	20.59	20.59	20.74
1996	4.00	2	6	6.65	20.84	21.45	21.48	undefined
1997	4.00	0	6	6.65	21.40	21.82	22.25	undefined
1998	4.00	0	6	6.65	21.99	22.42	22.72	undefined
1999	4.00	0	6	6.65	22.61	23.08	23.39	undefined
2000	4.00	0	6	6.65	23.25	22.97	23.31	23.33

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 0%, N (1995-2000) = 6 sen/kWh

Table A.41 Capacity factor of 87% for all IPP Plants

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.74	20.74	20.73
1996	4.00	2	8	6.65	20.84	21.83	21.95	undefined
1997	4.00	1	8	6.65	21.26	22.20	22.88	undefined
1998	4.00	1	8	6.65	21.70	22.53	23.20	undefined
1999	4.00	1	8	6.65	22.15	22.74	23.34	22.75
2000	4.00	1	8	6.65	22.62	22.86	23.29	22.87

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh; original rates for all contracts

Table A.42 Capacity factor of 75% for all IPP Plants

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.82	20.82	20.81
1996	4.00	2	8	6.65	20.84	22.13	22.32	undefined
1997	4.00	1	8	6.65	21.26	22.56	23.45	undefined
1998	4.00	1	8	6.65	21.70	22.87	23.80	undefined
1999	4.00	1	8	6.65	22.15	23.07	23.92	23.08
2000	4.00	1	8	6.65	22.62	23.16	23.82	23.16

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh; original rates for all contracts

Table A.43 Capacity factor of 75% for all IPP plants and 12.5 sen/kWh fixed purchase price for all contracts

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.82	20.82	20.54
1996	4.00	2	8	6.65	20.84	21.99	22.17	20.74
1997	4.00	1	8	6.65	21.26	22.43	23.23	21.01
1998	4.00	1	8	6.65	21.70	22.76	23.60	21.34
1999	4.00	1	8	6.65	22.15	22.99	23.75	21.65
2000	4.00	1	8	6.65	22.62	23.07	23.67	21.98

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.44 Capacity factor of 75% for all IPP plants and 15.5 sen/kWh fixed purchase price for all contracts

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	21.08	21.08	21.09
1996	4.00	2	8	6.65	20.84	22.42	22.79	21.66
1997	4.00	1	8	6.65	21.26	22.80	23.90	22.00
1998	4.00	1	8	6.65	21.70	23.10	24.21	22.25
1999	4.00	1	8	6.65	22.15	23.25	24.26	22.57
2000	4.00	1	8	6.65	22.62	23.34	24.13	22.89

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Table A.45 Base case capacity factors with YTL contract negotiated with Segari rates

Year	CPI (%)	M (%)	N (sen)	Y (sen)	A (w/o IPPs) (sen/kWh)	A (w/ IPPs) (P=P) aggr	(P=A) aggr	(P=P) indiv
1992					19.73	19.73	19.73	19.73
1993	4.25	2	8	6.65	20.02	20.02	20.02	20.02
1994	4.25	2	8	6.65	20.33	20.33	20.33	20.33
1995	3.70	2	8	6.65	20.56	20.25	20.25	21.72
1996	4.00	2	8	6.65	20.84	20.84	20.62	undefined
1997	4.00	1	8	6.65	21.26	21.49	21.49	undefined
1998	4.00	1	8	6.65	21.70	22.01	22.18	undefined
1999	4.00	1	8	6.65	22.15	22.66	22.89	103.86
2000	4.00	1	8	6.65	22.62	22.45	22.82	23.98

Notes: CPI (1996-2000)=4.0%, M (1993-1996) = 2%, M (1997-2000) = 1%, N (1995-2000) = 8 sen/kWh

Appendix B

The Malaysian Grid Code

Excerpts from the Malaysian Grid Code will be presented in this appendix. Specifically sections from the Introduction, the General Conditions, the Planning Code, the Systems Operation Code, the Scheduling and Despatch Code, and Connection Code are included.

1.0 INTRODUCTION

1.1.3. The Grid Code provides criteria guidelines and procedures for the licensees of electric power systems to coordinate the development and operation of the Grid System.

1.1.4 It is recognized that prior to the introduction of this Grid Code, Generation Licensees have concluded Power Purchase Agreements which may be at variance to the provisions of this Grid Code. Nothing contained in this Grid Code is intended to modify the parties' rights and obligations under the Power Purchase Agreement. In the event of any conflict, the Power Purchase Agreements take precedence only to the extent that it does not affect the security and safety of the Grid System.

1.2 SCOPE

1.2.1. The Grid Code shall be complied by all Generation Licensees (hereinafter "Generators"), the Grid System Operator and Distribution Licensee (hereinafter "Distributors") in the course of its Generation Business, Transmission Business and Distribution Business.

1.2.2. It shall be administered by Malaysian Grid Code Committee through Grid System Operator, who will be empowered by the Director General of the Department of Electricity Supply (hereinafter "Director General").

1.4 RESPONSIBILITIES

1.4.2 "The responsibilities of Grid System Operator are:
(i) the operation of the Grid System is supervised and controlled by the Grid System Operator who is, for the time being, owned by Tenaga National Berhad. The Grid System Operator also has the additional responsibilities to coordinate the planning and operation of the Grid System as described in this Grid Code.
(ii) perform any monitoring and reporting function as required to implement the Grid Code
(iii) submit periodic reports to the Licensees, Grid Code Committee and the Director General of the Department of Electricity Supply
(iv) provide services to coordinate interconnection facilities; and

(v) provide for the Director General the necessary data for the development and expansion plans of the Grid System.

2.0 GENERAL CONDITIONS

General Conditions apply to all provisions of the Grid Code. Their objective is to ensure, to the extent possible, that the various sections of the Grid Code work together for the benefit of all Generators, Distributors and the Grid System Operator.

2.1 UNFORESEEN CIRCUMSTANCES

2.1.1 If circumstances arise which the provisions of the Malaysian Grid Code have not foreseen, the Grid System Operator shall, to the extent reasonably predictable in the circumstances, consult promptly all affected Generators or Distributors in an effort to reach agreement as to what actions, if any, should be taken.

2.2 THE GRID CODE COMMITTEE

2.2.1 The Department of Electricity Supply (DES) shall establish and maintain the Grid Code Committee.

2.2.2 The Committee shall be fully responsible to the Director General and shall (a) keep grid code under review, (b) review all suggestions for amendments to grid code, (c) publish recommendations as to amendments, (d) issue its guidance in relation to the Grid Code and ensure implementations, performance and interpretation when asked to do so by any generator or distributor, and (e) consider changes necessary to the code arising out of any unforeseen circumstances.

2.2.3. The Committee shall consist of ... an officer from the DES, appointed by the Director General and approved by the Minister of Energy, two other officers from the DES, two representatives of the Grid System Operator, ten representatives from TNB, two representatives from each Generator (other than TNB), two members from each Distributor (other than TNB), and two members from each Transmitter (other than from TNB).

2.3 MEETING

2.3.3 The Grid Code Committee will meet for a minimum of four times every year to perform its function.

2.7 PROCEDURES TO SETTLE DISPUTE

(matter of dispute may be referred to the Director Genera ... and re-consideration to Minister may be sought)

3.0 PLANNING CODE

3.1 I INTRODUCTION

The Planning code is the section of Grid Code that contains guidelines, criteria, procedures, and methodologies to coordinate the planning and development of the Grid System.

3.1.1 OBJECTIVE

The objective of the Planning Code is to ensure operational safety and uniform standards so that the Grid System has sufficient resources and facilities and that adequate electrical energy at reasonable cost is available to meet the future electricity demand in Malaysia under normal and emergency conditions.

3.1.2 COORDINATION REQUIREMENTS

3.1.2.1 Load forecasts for expansion planning as well as for operational planning need to be consolidated and adjusted to optimize the reserve margins and operating margins for the overall Grid System. The consolidation and adjustment of load forecast shall be carried out by the Grid System Operator to establish the overall resource requirements.

3.1.2.2 The review for additional generation capacity and transmission capacity will be submitted by the Grid System Operator to the Director General in order to further optimize the requirements on a system-wide reserve margin basis.

3.1.2.3 All system additions will be reviewed, coordinator and recommended by the Grid System Operator to the Director General.

3.2 RESPONSIBILITY

3.2.1 The primary responsibility to forecast the adequacy and availability of electrical energy supply to customers belong to the Distributors in the areas as specified in the terms of their license. Accordingly, they are responsible for determining their load forecasts of their areas. The Grid System Operator need to coordinate the expansion of the respective generation resources and transmission facilities with other Generators or Distributors.

3.2.2 The Distributors are required to submit their load forecasts and expansion plans to the Grid System Operator annually, or whenever changes are made in the existing forecasts and plans.

3.2.7 STATEMENTS OF SYSTEM CAPACITY - THE GRID SYSTEM OPERATOR

3.2.7.1 In order to assist the DG to identify and evaluate the constraints for connecting to and making use of the Grid System, the Grid System Operator shall prepare a set of statements showing, in respect of each of the five succeeding years commencing with the current year, its best estimates and forecasts of circuit capacity, power flows and loading on each part of the Grid System, together with forecast fault levels for each transmission node to the Director General.

3.3. LOAD FORECASTS

(Distributors responsible for load forecasts -- to be submitted annually by Nov. 1)

3.3.1.1 Short-Term Load Forecast

The short-term load forecast will cover the period of 1 to 2 years. This forecast is require to prepare the annual operation plan that identifies the schedule maintenance outages and unit operations schedule. It is also used to prepare the Grid System configuration to maintain reliable operation. It consists of the annual peak load and energy requirements and the expected load-shape curve. ...

3.3.1.2 Mid-Term Load Forecast
The mid-term load forecast is considered to cover a 2 to 5 year period. This forecast is required to schedule any major facility outages for maintenance. It is also required to review the resource availability and determine any shortfalls. Short-term measures are determined to overcome the generation shortages, if any, that may include additional imports from neighboring countries, emergency construction of gas turbines, and load management programs. The mid-term load forecasts also consist of annual peak load and energy projections along with the hourly load-shape curve. ...

3.3.1.3. Long-Term Load Forecast
The long-term load forecast covers a period of 6 to 10 years. This forecast is required to perform the expansion planning studies for generation and transmission facilities. ...

3.3.2.3 The Grid System Operator is responsible for reviewing and adjusting the load forecasts for the overall Grid System by (a) the coincidence of hourly load shapes or (b) the addition of any bulk loads or other anticipated demand not considered by the Licensees. The resulting load forecast will form the basis of the coordinated expansion plan of the Grid System as discussed in 3.4.

3.3.2.6 The short-term load forecast will form the basis of an annual operations plan to be implemented by the GRID SYSTEM OPERATOR.

3.4 EXPANSION PLANNING

3.4.2.1 The GRID SYSTEM OPERATOR is responsible to co-ordinate, review, develop and recommend plans for the addition of generation and transmission facilities to the Director General.

3.4.2.3 All Generators or Distributors shall submit their respective expansion plans to the GRID SYSTEM OPERATOR by November 1 of each year or whenever previous plans are changed. ...

3.4.2.5 The GRID SYSTEM OPERATOR will review the expansion plans and make any changes that may be necessary to meet the objectives for the Grid System development.

3.4.3 PLANNING CRITERIA

a. Reserve Margin Criteria: The generating resources in any year will be maintained at a reserve margin sufficiently higher than the projected annual peak demand of the Grid System;
b. Loss-of-Load Expectation Criteria: The Loss-of-load expectation (LOLE) index should not exceed 1 Day per Year. LOLE is the expected number of hours in a time period when insufficient generating capacity is available to serve all the load;l
c. Transmission Planning Criteria: The transmission system will be planned to operate at all load levels to meet the following unscheduled contingencies without instability, cascading, or interruption of load: the loss of any single generating unit, transmission line, transformer or bus, without exceeding the applicable emergency rating of any facility; and
d. Voltage Regulation: The system will be planned to withstand voltage deviation from +10 percent to -10 percent of the nominal voltage.

3.4.4 GENERATION EXPANSION PLANNING

The Grid System Operator will review and revise the generation additions in the Grid System to recommend to the Director General additional generators that meets the following condition:
a. Meets the reserve margin criteria, and/or
b. Meets the loss of load expectation criteria; and
c. Results in optimum capital and operating costs.

3.4.4.4 Production Costs
Estimates of production costs of the alternative expansion plans will be determined through production simulation calculation on a standard software program to be identified by Grid System Operator.

3.4.4.6 Optimal Plan
The 10 year (15 year) expansion plan alternatives will be compared to identify minimum costs additions plan.

3.4.5 TRANSMISSION EXPANSION PLANNING

(The review and revision of the transmission expansion of the Grid System (by GRID SYSTEM OPERATOR) to ensure that (a) transmission planning criteria are met and (b) voltage regulation criteria are met will include: Load forecast distribution on the system buses, generating schedules, and power flow simulation.

3.4.5.4 Minimum cost alternatives of the transmission system addition will be determined.

3.4.6 TRANSACTIONS WITH NEIGHBORING COUNTRIES
In reviewing and revising the expansion plans of the GS, the GRID SYSTEM OPERATOR will give due consideration to the availability of capacity and energy resources from neighboring countries.

3.4.6.1 The types of electric power/energy transactions which may take place with the neighboring countries vary according to the short- and long- term need of power or energy, the availability of power or energy, and the relative amount of transmission interconnections among the systems.

3.4.6.2 The interconnection agreements with the neighboring countries should normally include the definitions of the various classes of power/energy to be exchanged or sold. Rate schedules specifying terms covering the charges for the various classes of power/energy are usually appended to the agreement.

3.4.7 REACTIVE REQUIREMENTS

3.4.7.1 All Generators and Distributors are required to ensure availability of reactive resources to meet the requirements of their respective systems. Generators shall operate at a power factor range from 0.9 leading to 0.85 lagging as measured at the terminals of each Generating Unit. Distributors are to ensure availability of adequate reactive resources in order to maintain a power factor of 0.9 at the 132 kV busbar connection point.

3.4.7.2 Any additional reactive resource requirements necessary for the operation of the Grid System will be determined by the Grid System Operator and allocated to the appropriate Generator or Distributor. The costs related to the additional reactive power supply will be equitably distributed among the Generators or Distributors or as may be mutually agreed upon.

3.5 DATA REQUIREMENTS

Coordination of expansion plans for the GS by the GRID SYSTEM OPERATOR requires data . . .

3.5.1 FORECAST DATA
3.5.1.1 (annual peak load and energy projection (MW and MW-hours))
3.4.1.2 (annual hourly load-shape data)

3.5.2 GENERATION DATA
3.5.2.1 Generating Unit Data
(see attached)

3.5.3 TRANSMISSION DATA

3.5.4 DISTRIBUTION SYSTEMS DATA

3.5.5 CAPITAL COST AND OPERATING COST DATA

4.0 SYSTEM OPERATIONS CODE

4.2 OPERATIONAL PLANNING
The operational plans for the Grid System are based on the operations criteria to maintain the reliability and continuity of supply. The general operational planning criteria consists of the following:
4.2.2.1 MW Regulation
4.2.2.2 Voltage Control
4.2.2.3 Time and Frequency Regulation
4.2.2.4 Inadvertent Interchange management
4.2.2.5 Control Surveys

4.3 OPERATING RESERVES CRITERIA
(Spinning Reserve: Primary, Secondary, and Five Minute Reserve;
Non-spinning Reserve: output available from standby generating units that can be synchronized and loaded up within an hour to cater for abnormal demand increased or further generating units breakdown)

4.3.3 ALLOCATION OF OPERATING RESERVE
...
The allocation of the operating (spinning) reserve among the thermal Generating Units should be based on merit order with due consideration to system security. In any case the operating reserve should be large enough to cater for the loss of a Generating Unit that carries the highest load in the system.

Non-spinning reserve can be allocated to hydro generators, gas turbines and any Generating Unit as long as these Generating Units have not been allocated as part of the spinning reserve and they can be synchronized and put on bars within 1 hour.

4.4 SYSTEM VOLTAGE AND REACTIVE POWER CRITERIA

4.4.3 COORDINATION BY THE GRID SYSTEM OPERATOR
On the basis of the expected power flows, the Grid System Operator will determine the required voltage profile of the system and allocate the MVAr generation and reactive reserve capacity required in each section of the system and Generating Unit to ensure the maintenance of satisfactory levels in the event of loss of circuits.

The GRID SYSTEM OPERATOR will arrange the reactive output of Generating Unit to meet the reactive requirements as economically as possible.

4.5 OPERATIONS PLANS

(Each generator and GRID SYSTEM OPERATOR shall plan for normal operations, emergency conditions, long-term deficiencies, load shedding, system restoration and communications for the grid system.)

4.5.4 ANNUAL OPERATIONS PLAN

4.5.4.1 Basic Guidelines

The Annual Operations Plan shall contain sufficient information in a suitable form to assess the following:

a. The adequacy and capability of Generating Units to meet forecast demand and energy for the next year to 5 years ahead;

b. That generation and transmission outages are planned to maximize resource utilization, optimize hydro/thermal regimes and placement of generation outages to produce a minimum running cost;

c. The operational problems likely to be encountered are highlighted and alternative solutions considered and evaluated; and

d. The actions taken and emergency procedures issued to deal with possible abnormal system conditions are adequate and satisfactory.

4.5.5 WEEKLY OPERATIONS PLAN

a. (GRID SYSTEM OPERATOR will issue prelim. weekly operations plan that will include all generating units that are on standby duty as non-spinning reserve)

b. (within two days of this, the GRID SYSTEM OPERATOR will prepare a weekly operations plan that takes into account the generating units unavailability)

c. (each week, the GRID SYSTEM OPERATOR determines the allocation of reserve margin to each generator with due consideration to start-up prices, response characteristics of the generating units on the grid system, system constraints, availability of generating units, hydro dam levels and the lake inflow rates in its weekly operations plan)

d. (the weekly operations plan shall include amount of operating reserve to be utilized by the GRID SYSTEM OPERATOR in scheduling and despatching process)

e. (may include possible shared spinning reserve with the neighboring utilities)

4.6 TRANSMISSION OPERATIONS PLANNING

5.0 SCHEDULING AND DESPATCH CODE

5.1.2 Generation Scheduling procedures include the following:

a. the submission of an Availability Declaration by each Generator;

b. the submission of any revised generating scheduling and despatch parameters in respect of the following Availability Declaration Period by each Generator;

c. the submission of certain system data by each Generator;

d. the issue of a Generation Schedule the day before the schedule day for the Grid System Operator operational requirement;

e. Where an Externally Interconnected Party outside the country is connected with the Grid system for the purpose of system security enhancement and economic operation (e.g. sharing of spinning reserve) the generation scheduling and hence power transaction will be governed by agreed Inter-Utility Joint Operation manual and any other Inter-Utility agreements; and

f. Generation scheduling requires generator data to enable the Grid System Operator to prepare a Merit Order to be used in the scheduling (Unit Commitment) and despatch (Economic Despatch) process and the preparation and issue of a Generation schedule. Based on this data, the GRID SYSTEM OPERATOR is required to ensure that there is sufficient generation to meet system demand at all times in the most economic manner together with an appropriate margin of reserve, whilst maintaining the integrity of the Grid System and security and quality of supply.

5.1.3 PROCEDURE

5.1.3.2. By 1000 hours each day each Generator, shall submit to the Grid System Operator in writing the above information (availability declaration, generating scheduling and generation despatch parameters and other relevant generation data) which shall be applicable for generation in respect of the next period (following data) from 0000 hrs to 2400 hrs.

5.1.3.4 The generation schedule will be submitted to the relevant generators by 1530 hours.

5.1.4 AVAILABILITY DECLARATION

(whole number of MW in respect of any time period)

5.1.5 GENERATION SCHEDULING AND DESPATCH PARAMETERS

(shall reasonably reflect true operating characteristics of the generating units)
(generation schedule will be compiled daily by the GRID SYSTEM OPERATOR as a statement of which units may be required for the next following schedule day ... in compiling this schedule, factors that will be taken into consideration: grid system constraints, parameters of generation units including indications of the gen. units inflexibility, requirements for voltage control and MVAr reserves, the need to provide an operating margins, and requirements for maintaining frequency control)

(additionally, schedule will be in accordance with the merit order table and taking into account the startup price element of the generation offer price, as will be sufficient to match at all times the forecast system demand together with an appropriate margin of reserve as identified in the weekly operational policy, and as will in aggregate be sufficient to maintain frequency control).

5.1.7. DISTRIBUTOR SYSTEM DATA

(each day, distributor will submit constraints on its distribution system and the requirements of voltage control and MVAr reserves)

5.2 MERIT ORDER OPERATION

5.2.1 To meet the continuously changing demand on the Grid System in the most economical manner, Generating Units should be, as far a practicable, put on load and loaded up in accordance with the least variable "operation and maintenance costs inclusive of cost of fuel and consumables" (hereinafter "O&M costs") of producing electricity from each Generating Unit. Fixed costs are not taken into considerations. At any time a minimum total amount of plant, with the least variable O&M costs, is used to meet the demand with a satisfactory margin.

5.2.3 The Order-Of-Merit schedule (listing generating units according to the least variable O&M costs of producing electricity) is divided into 3 section:
a. Merit order for scheduling plant on and off the system; cost for each generating unit is derived from the average heat rate.
b. Merit Order for determining the generated output of Generating Units which are on load; cost for each set is derived from incremental heat rates.

c. Minimum economic shut down period for each Generating unit; this is derived from the no load heat rate and allowances derived from the heat consumed in a hot and cold start of the boiler and the heat consumed per hour in banking the boiler.

5.2.5 (various heat rates required for thermal plants)

5.2.6 ECONOMIC DESPATCH

a. The normal method adopted is to divide each day into a number of operating periods, depending upon the number of peaks, troughs and constant levels in the estimated demand curve.

b. For each operating period, unit commitment requirement on the bars is determined by computer simulations. This value is the sum of the estimated maximum demand for the period and the specified spinning reserve plant.

c. Plant which is required to run for security or inflexibility purposes is allocated first. This is followed by Hydro Plant allocation in accordance with the required Hydro Operation regime. Selection of plant to meet the remainder of the total required capacity is then made from the Thermal Merit Order Tables starting with the highest merit plant (least variable operation and maintenance costs) available until the required total is accumulated.

d. In cases where only partial loading of a set is required for security or inflexibility reasons, the assessment of whether or not to use the remainder of the set capacity is determined, in the case of thermal plant, from the incremental heat rate of the lowest merit plant selected to run.

5.3 SYSTEM OPERATIONS

5.4 CONTROL SCHEDULING AND DESPATCH

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