ASIA PACIFIC ENERGY RESEARCH CENTRE

APEC ENERGY PRICING PRACTICES

IMPLICATIONS FOR ENERGY EFFICIENCY, THE ENVIRONMENT AND SUPPLY INFRASTRUCTURE

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FOREWORD

Energy pricing is an essential component of policies that address the triple objectives of improving energy efficiency, protecting the environment and facilitating energy infrastructure investment. The analysis of energy prices and pricing practices adopted by APEC economies can provide constructive insights about the operation of energy markets.

Recognising the importance of energy pricing, the APEC Energy Working Group (EWG) endorsed the APERC's research in to energy pricing at their 14th meeting in Santiago, Chile during May, 1997. APERC began its work on energy pricing practices, along with five other research projects, following the completion of the updated APEC Energy Supply and Demand Outlook in September 1998.

The objective of the energy pricing research was to establish the implications of different energy pricing practices in the APEC region on energy efficiency, the environment and supply infrastructure. In addition, the project also aimed to establish an APEC Energy Pricing Database to be utilised for the analysis of pricing practices throughout the APEC region.

Energy pricing is an essential component of policies that address the triple objectives of improving energy efficiency, protecting the environment and facilitating energy infrastructure investment. The analysis of energy prices and pricing practices adopted by APEC economies can provide constructive insights about the operation of energy markets.

I would like to express my sincere gratitude to my fellow APERC researchers who have been involved in this research, and also to the many experts who have contributed valuable comments as APERC's research progressed.

Keiichi Yokobori

President.
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BACKGROUND

The rapid economic growth that has taken place in the APEC region over the past two decades has transformed the dynamics of the regional energy market. Strong economic growth, particularly in the economies in Southeast and Northeast Asia, has markedly increased regional energy demand, and required huge investments on the supply side, in both APEC and non-APEC economies. Between 1980 and 1995, APEC regional energy consumption grew by 35 per cent, and is expected to grow by a further 41 per cent over the period from 1995 to 2010 (APERC, 1998b).

At the same time, energy policies have continued to develop and the focus has broadened from energy security issues to other issues, such as energy efficiency and environmental conservation. The mechanism for achieving these policy goals has moved towards market liberalisation, with governments moving away from direct intervention and towards the creation of re-regulated competitive markets. As markets have been gradually liberalised, many governments have privatised their energy assets.

As energy markets gradually transformed, energy pricing practices have also changed – ultimately facilitating the balance between demand and supply. This report examines and appraises alternative energy pricing practices in APEC economies, and the implications for energy efficiency, supply infrastructure and the environment.

APERC RESEARCH

At the Inaugural Meeting of APEC Energy Ministers, held in Sydney during August 1996, Australia, APEC Energy Ministers adopted 14 Non Binding Energy Policy Principles to be considered by APEC economies in the formulation of energy policies. Principle 5 specifically addresses the importance of energy pricing for APEC member economies:

> Principle 5: *Consider reducing energy subsidies progressively and promote implementation of pricing practices which reflect the economic cost of supplying and using energy across the full energy cycle, having regard to environmental costs.*

Recognising the importance of energy pricing, the APEC Energy Working Group (EWG) endorsed APERC's research in to energy pricing, and the implications for energy efficiency, the environment and supply infrastructure at their 14th meeting in Santiago, Chile during May, 1997. The research programme at APERC commenced following the completion of the Updated Outlook for APEC Energy Ministers in October 1998.

APERC's pricing practices research programme was developed to address the following three fundamental objectives:

- develop information and data bases adequate for analysis of energy prices and pricing practices in the APEC member economies;
- analyse the energy pricing practices in the APEC member economies on both empirical and theoretical bases; and,
- derive policy implications for energy pricing policies for energy efficiency, the environment, and supply infrastructures for the APEC member economies.

In the course of the research, APERC committed itself to developing an APEC Energy Pricing Database, as well as conducting a policy survey of energy pricing practices among APEC economies. A preliminary draft of the policy survey is provided in Chapter 4 of this report. The APEC Energy Pricing Database has yet to reach completion.

ENERGY PRICING PRACTICIES IN THE APEC REGION

Energy pricing is important not only at the level of individual economies, but also at the regional and global level. Many economies in the APEC region have undertaken; or are in the process of undertaking; reforms that aim to restructure the energy sector and provide competitive energy markets. Within the context of these reforms, energy pricing has become a fundamental component of the restructuring program. At the same time, governments are also studying and reviewing the effectiveness of energy pricing policies as an instrument to achieve environmental objectives, such as greenhouse gas emission abatement.

Energy pricing is influenced by many factors, including government and private sector objectives, as well as external influences. Private sector objectives include the desire to increase market share, ensure financial viability and deliver profits to shareholders. Pricing may also differ as a result of the different cost structures of energy utilities. Government objectives reflect a wide range of economic, social and political goals, which can be achieved through energy pricing policies. External influences, such as exchange rate variations, may also impact heavily in the energy pricing process.

In the APEC region, energy policies commonly subsidise, cross-subsidise, impose import tariffs, taxes, levies as well as setting required standards and regulations – all of which affect the final end-use energy price. Although in most cases the subsidies and tariffs on energy products are not high, the overall effect is significant and results in lower economic efficiency and welfare.

As the circumstances of each economy and individual energy market vary, the appropriate energy policy objectives, and the mechanisms for achieving the objectives will differ. Therefore it is not possible to apply a uniform energy pricing approach to each economy in the APEC region. The energy sector remains an area of particular interest to governments throughout the world due to the strong linkage between the sector and the economic and social well-being of an economy. Schramm (1995) highlights three basic objectives of energy pricing policies with respect to energy pricing:

- economic efficiency;
- social equity, and;

- financial viability.

Under Schramm's model, efficiency principle seeks to ensure the regulation of prices in such a manner that the allocation of the society's resources to the energy sector fully reflects their values in alternative uses. The equity principle relates to welfare and income distribution considerations. This may result in implementing differential pricing schemes on grounds of basic and essential needs, or the establishment of uniform prices to specific user groups regardless of the different costs of supply, justified on the basis of regional equity or similar concerns. The financial principle suggests that energy supply systems should be able to raise sufficient revenues to remain financially viable, so that continuity and quality of service is ensured, and future investment requirements are achieved.

For the environment, currently, there is no specific energy-related environment tax (carbon tax) in any APEC member economy. In many empirical studies, it is observed that not all the efficiency gains can be attributed to prices effects, much less to tax-induced price effects. In many cases, price variables were shown to be less significant than income in energy demand modelling, particularly for developing economies. GDP per capita was a better explanatory variable for increased CO_2 emissions than energy prices, and further indicated that as a result of the inelasticity of energy prices it was difficult to foresee how increasing prices, within acceptable limitations, could be used as a policy instrument for reducing greenhouse gas emissions. This result supported Canadian government indications that a carbon tax (resulting in increased final energy prices to energy consumers) is ineffective and should not be used.

STRUCTURE OF THIS REPORT

This report has been written as a preliminary draft and discussion document for APERC's Annual Conference. The report is structured as follows: Chapter 1 reviews the Pricing Project Research taking place at APERC, including the relationship between the pricing study and the goals of the APEC EWG process. Chapter 2 considers, from a theoretical viewpoint, some of the energy pricing objectives and energy pricing approaches common in energy markets. Chapter 3 examines current energy pricing practices in the APEC region in the coal, petroleum products, natural gas and electricity markets, while Chapter 4 provides a more detailed review of energy pricing mechanisms in individual APEC economies. Finally, Chapter 5 summarises the major findings to date and briefly discusses a few issues for future work.

CHAPTER 1

APERC's Energy Pricing Research

OVERVIEW

Energy pricing is an important aspect for promoting the triple objectives of improving energy efficiency, protecting the environment and ensuring investment for infrastructure of energy supply. Energy prices need to cover the costs of production and investments to satisfy the internal cost of energy suppliers. More recently, a growing awareness of environmental degradation has required that, in some instances, these external costs be factored into the energy prices – bringing new challenges to energy policy makers.

Recognising the importance of energy pricing, the APEC Energy Working Group (EWG) endorsed APERC's research in to energy pricing, and the implications for energy efficiency, the environment and supply infrastructure at their 14th meeting in Santiago, Chile during May, 1997.

This chapter reviews the general terms of reference and project objectives that has guided APERC's energy pricing research. The scope of research and methodology adopted by APERC is also explained with regard to the development of the APEC Pricing Database and particular aspects of the energy pricing research and analysis. Also included are summaries of APERC's Energy Pricing Workshops that aimed to provide a forum for experts to discuss energy pricing issues, and for APERC to further develop expertise in the field of energy pricing.

BACKGROUND

Energy pricing mechanisms are typically complex and vary widely across the APEC region. Different economies have different regulatory systems, different policy frameworks, and different energy policy goals and objectives. In the APEC region, energy policies commonly subsidise, cross-subsidise, impose import tariffs, taxes, levies as well as setting required standards and other regulations. Although in most cases the subsidies and tariffs on energy products are not high, market distortions still occur, resulting in lower economic efficiency and wealth.

To ensure that energy markets facilitate improvements in energy efficiency, protect the environment and provide ample opportunities for investment in supply infrastructure, it is imperative that distortions are minimised and that the principles of consistency, transparency, clarity and cost-effectiveness are promoted.

At the Inaugural Meeting of APEC Energy Ministers, held in Sydney during August 1996, Australia, APEC Energy Minister adopted 14 Non-Binding Energy Policy Principles to be considered by APEC economies in the formulation of energy policies. Principle 5 specifically addresses the importance of energy pricing for APEC member economies:

> Principle 5: *Consider reducing energy subsidies progressively and promote implementation of pricing practices which reflect the economic cost of supplying and using energy across the full energy cycle, having regard to environmental costs.*

Ministers also agreed that the research projects assigned to the Asia Pacific Energy Research Centre (APERC) would include investigating environmental impacts from energy developments and impediments to trade and investment in primary energy. APERC was also requested to conduct research aimed at indicating pathways that economies could follow to eliminate these impediments.

In developing the APEC Energy Demand and Supply Outlook for the APEC region in 1997, APERC determined two major difficulties in conducting analysis in the area of energy pricing. In the first instance, lack of reporting and transparency meant that published energy pricing data was often inadequate. Secondly, a thorough examination of energy pricing practices is required before any comprehensive research could be undertaken to analyse the implications for the energy demand and supply sectors as well as for the environment.

During their 14th meeting held in Santiago, Chile, the APEC Energy Working Group approved APERC's energy pricing research proposal. The project commenced at the conclusion of research associated with the APEC Energy Demand and Supply Outlook in 1998.

RESEARCH OBJECTIVES

The objectives of this study are:

a) develop information and data bases adequate for analysis of energy prices and pricing practices in the APEC member economies;

b) analyse the energy pricing practices in the APEC member economies on both empirical and theoretical bases; and,

c) derive policy implications for energy pricing policies for energy efficiency, the environment, and supply infrastructures for the APEC member economies.

THE SCOPE OF RESEARCH

COVERAGE OF ECONOMIES

This study covers all twenty-one APEC member economies, including new members joining APEC in 1998, namely the Russian Federation, Viet Nam and Peru. However, limitations in the availability of data and relevant pricing information are a significant constraint in the study and therefore although all economies have been covered, the level of detail varies. In cases where pricing information and data are extremely limiting, APERC has endeavoured to provide as much information as possible believing that it may be useful in future studies of energy pricing where the availability of pricing data and information is less constrictive.

Table 1 APEC Regional Classifications

APEC SUB-REGIONS	APEC MEMBER ECONOMIES
Americas	Canada, Chile, Mexico, Peru, United States
East Asia	China; Hong Kong, China; Japan; Korea; Russia; Chinese Taipei
Southeast Asia	Brunei Darussalam, Indonesia, Malaysia, Philippines, Singapore, Thailand, Viet Nam
Oceania	Australia; New Zealand; Papua New Guinea

ENERGY PRICING DATABASE

The databases and analyses in this study cover the prices, wholesale as well as retail, and taxes of energy and fuels in the commercial energy market, such as oil products, electricity, natural gas, and coal products. Time series data in each economy, from 1980 to 1998, will be compiled with annual data in the database.

APERC's strategy is to collate energy pricing data and information from established sources, rather than collecting data in the first instance. This is necessary due to the limited resources available to APERC, and the ability of APERC to draw on established resources in individual economies and international organisations.

Keeping with established APEC protocol, determined by the APEC Expert Group on Energy Data and Analysis (EGEDA), the database will be denominated in TOE (tonne of oil equivalent), which permits analysis to compare between alternative energy commodities. However, recognising that many users will be familiar with examining prices in the base unit, energy prices are readily convertible to their original unit.

POLICY SURVEY AND ANALYSIS

The analyses will cover current energy pricing policies in APEC economies, including description of the energy pricing mechanism, subsidies and cross-subsidies, taxation and levy systems, and regulatory structures in each economy with the capacity to influence energy prices.

The survey of energy pricing policies is derived from various sources of information including specific APEC economy energy contacts, information gathered from relevant energy workshops and conferences, international organisations, relevant reports and other general information. In conducting the survey of energy pricing policies, APERC worked closely with EGEDA representatives.

ENERGY PRICING ANALYSIS

The pricing analysis is aimed at determining what the likely implications of alternative energy pricing practices have on energy efficiency, the environment and supply infrastructure. Three analytical methodologies are used.

Firstly, graphical analysis of energy prices on an inter- and intra-economy basis are used to determine trends between energy prices in different economies and between energy commodities.

Secondly, simple statistical analysis is applied to determine the variability of energy prices that occurs under alternative energy pricing mechanisms, and also examine the characteristics apparent in price determination, and levels of correlation in energy pricing trends between commodities and economies.

Thirdly, in economies where sufficient energy pricing data has been obtained, detailed econometric analysis is undertaken to establish longer-term characteristics of the pricing data, and its relationship to economic and environmental indicators. Particularly, by examining the way energy demand responds to price changes, through price elasticities, it is possible to determine the likely implications associated with alternative energy pricing frameworks.

METHODOLOGY AND DATA FOR ANALYSIS

DEVELOPMENT OF THE APEC ENERGY PRICES DATABASE AND INFORMATION SET

In analysing the energy pricing mechanisms in each member economy, a standardised database for energy prices for the APEC member economies will have to be developed. However, this will be subject to the availability of the required data and their quality, and will be achieved advantageously in collaboration with the APEC Energy Working Group (EWG), Expert Group on Energy Data and Analysis (EGEDA) and the International Energy Agency (IEA). This database will eventually be linked with the existing APEC Energy Database, which is managed by the Energy Data and Modelling Centre, the Institute of Energy Economics of Japan (IEEJ), the coordinating agency of the EGEDA. Otherwise, price data necessary for the analyses will be gathered through ad hoc manners including the survey of the published information and questionnaire methods to the extent possible, and then will be compiled in a less comprehensive database.

POLICY SURVEY AND ANALYSIS

Data and other energy related information was collected from various sources to provide a brief overview of energy pricing policies. The sources for this information included energy and economic publications of each APEC member economy, existing literature sources, as well as domestic and international energy research organisations. Workshops and seminars organised by APERC provided a forum for the discussion of energy pricing policies among APEC economies.

ECONOMIC ANALYSIS AND POLICY IMPLICATIONS

Economic and empirical analysis of the effects of energy pricing on energy demand and supply structure, as well as capital requirements, and the environment will be conducted at the macro-economic level using the APERC Energy Outlook Model framework. Also, policy implications for energy and environment will be derived from findings of the empirical analyses. However, given the limited time constraints, case studies will be undertaken on a fuel basis (coal, petroleum products, natural gas, electricity), sectoral basis (residential, commercial, transport, industry, utility, independent power producers, etc.) and theme basis (energy efficiency, environment, infrastructure).

CHAPTER 2

THEORETICAL OVERVIEW OF ENERGY PRICING

OVERVIEW

Energy pricing is fundamental for the operation of efficient energy markets. Energy prices perform the important role of balancing consumer energy demand with producer supply. However, energy prices can have many other provide the revenue basis for the owners of energy generating, transmission and distribution assets. Pricing trends, reflecting the interaction of demand and supply, can be used to evaluate the need for further investment and changes in the level of production.

Governments also have taken advantage of energy pricing as a tool to achieve policy objectives. Energy taxation has been used not only as a source of government revenue, but also to promote energy and environmental conservation, influence consumer choice, improve efficiency and improve energy security. In some instances, government revenues have been specifically tied to public energy infrastructure projects, such as the provision of rail or port facilities. Governments have also used subsidisation and tax relief measures as a means of encouraging infant energy industries, particularly for new energy sources such as renewables.

A thorough understanding of the pricing mechanism could be considered more critical in energy markets due to the high capital intensity and long lead times associated with energy investments. Further, the essential nature of the service energy provides to all sectors of the economy requires that energy prices are set prudently and efficiently. If energy prices are held below the cost of production for social or industrial reasons, it can result in negative results in terms of over-consumption, environmental degradation and wasted national resources. Conversely, if prices are held artificially high, industrial competitiveness will suffer and some consumers would be deprived of an essential service.

As a result of the importance of energy, governments have traditionally maintained a close association with energy industries and, in some instances, these industries have been compulsorily nationalised – such as the nationalisation of the Mexican oil industry. More recently, although deregulation and privatisation initiatives have opened up energy markets, the industries have not been entirely emancipated as requirements for competition and free trade have often been legislated or referred to government monitoring agencies.

This chapter reviews some of the energy pricing objectives and energy pricing approaches common in energy markets.

APPROACHES TO ENERGY PRICING

The energy pricing process is influenced by many factors, including government and private sector objectives, as well as external influences. Private sector objectives include the desire to increase market share, ensure financial viability and deliver profits to shareholders. Pricing may also differ as a result of the different cost structures of energy industries. Government objectives reflect a wide range of economic, social and political goals, which can be achieved through energy pricing policies. External influences, such as exchange rate variations, may also impact heavily in the energy pricing process.

The basic objectives of energy pricing are economic efficiency, social equity, and financial viability. The efficiency principle seeks to ensure the regulation of prices in such a manner that the allocation of the society's resources to the energy sector fully reflects their values in alternative uses. The equity principle relates to welfare and income distribution considerations. This may result in implementing differential pricing schemes on grounds of basic and essential needs, or the establishment of uniform prices to specific user groups regardless of the different costs of supply, justified on the basis of regional equity or similar concerns. The financial principle suggests that energy supply systems should be able to raise sufficient revenues to remain financially viable, so that continuity and quality of service is ensured, and future investment requirements are achieved.

There are many different alternatives for pricing energy, often reflecting the energy policy framework determined by policy makers. The remainder of this section reviews some of the pricing alternatives available to energy industries.

MARGINAL COST PRICING

The concept of marginal cost pricing aims to maximise social welfare by pricing energy commodities at a level where, theoretically, the additional benefit of additional units of energy is compensated by the additional cost (short run marginal cost) of providing the extra unit of energy. If more energy was provided beyond this point, net welfare would decline as the additional benefits associated with consuming more energy, would be outweighed by the higher costs of providing that energy.

Marginal cost pricing is most commonly provided in countries where the energy utilities are publicly owned, and the enterprise is run so that the revenue generated is sufficient to cover the operating costs of the utility. Alternatively, where enough private utilities exist to create a highly competitive market, prices tend to converge towards the marginal cost as competition ensures cost minimisation in the production and optimal investment decisions.

Determining the level of the short run marginal cost is problematic in practice. The short run marginal costs will include factors such as the cost of raw fuels and other materials, labour costs and maintenance. Capital costs are assumed to be fixed in the short-run, and therefore are not included in the short run calculation. In the long run, capital can also be varied so that the long run marginal cost includes the cost of increasing output by expanding capacity. Generally, it is agreed that when price is set equal to the long-run cost, it leads to efficient decisions in relation to the level of investment in productive capacity.

Since the lifecycle of most energy projects are long, most economists agree that it is preferable to price energy according to the long run marginal cost. The Asian Development Bank strongly encourages this practice and it has successfully been used in France and, prior to privatisation of the electricity sector, the United Kingdom.

Marginal cost pricing has a number of attractive features in terms of allocative efficiency. By focusing on the future costs rather than previous sunk costs, consumers are provided with a more accurate reflection of the cost of their current decisions to consume an extra unit of electricity. Further, long-run marginal cost pricing reduces pricing volatility by spreading the “one off” costs, such as a replacement power plant, over a longer period of time.

In practice the use of a long-run marginal-cost pricing scheme is problematic due to the difficulty of accurately estimating the marginal cost. Long-run marginal costing attempts to estimate the cost of increasing production capacity in the future, rather than looking at costs already incurred. Long-run marginal cost pricing also does not provide for periods of short term market imbalances. For example, marginal cost pricing cannot incorporate short term pricing variations so that consumption can be rationed in periods of high demand.

Pricing according to the short-run marginal cost solves some of these problems, and does lead to an efficient use of existing capacity, as well as providing efficient signals relating to the need for any additional production capacity in the future. Allocative efficiency is also assured when the available production capacity is distributed according to the short run marginal cost. Despite the advantages, problems arise because of the short-term market volatility which makes it extremely difficult for regulators to adjust the price to match the short run marginal cost. Further, the constantly changing price is unpredictable for consumers, and makes long term investment decisions difficult for the energy supplier.

Pure marginal cost pricing may also involve generic energy commodities being priced differently. This result is common in the electricity industry where are variety of different generators may rely on different methods to generate electricity at different costs. For example, nuclear and hydro electricity generation is characterised by low running costs and high capital costs, while fossil fuel fired generators tend to have higher running costs and lower capital costs. Therefore marginal cost pricing will tend to create bias towards particular types of electricity generation. This problem is reduced when the long run marginal cost is used as a basis of pricing since the replacement cost (or depreciation) is taken into account as a running cost.

On balance, most economists agree that the most practical system of marginal cost pricing involves some comparison with the long run marginal cost. However, this pricing mechanism may not be appropriate when the private sector is involved. For example, since long run marginal cost pricing takes no account of past sunk costs, it is difficult for suppliers to incorporate an ongoing interest component on borrowing used to finance the sunk costs. Some pricing mechanisms have been devised that overcome these problems, such as the “Ramsey” pricing mechanism that allows costs to be recovered by splitting a tariff into at least two parts and adding a mark-up to cover sunk investment costs.

HISTORICAL COST RECOVERY PRICING

Historical cost recovery pricing involves energy suppliers pricing energy commodities at a level that permit an acceptable market rate of return to be earned and also allows recovery of past expenditures, such as the cost of oil exploration and the construction costs of a drilling rig. Historical cost recovery pricing is widely used around the world, in both highly regulated and loosely regulated economies.

Depending on the level of market regulation, the price may be officially set by government or left to competitive market forces. In some countries, the government not only determines the level of price, but also determines the structure of tariff for different consumer groups.

In the United States a formally developed system operates where the rate of return which can be earned by energy producers must be just and reasonable, and not result in any undue preference or discrimination. Producers are allowed to recover operational costs, plus a reasonable rate of return on capital investments. The rate of return is regulated on a state by state basis by various state utility commissions.

The historic cost recovery method of pricing has a number of positive attributes. The historical cost of production capacity is easily determined, allowing the rates of return to be accurately calculated. The system is relatively simple for consumers and producers, and also lowers the investment risk to energy suppliers.

However, a historical cost recovery pricing mechanism can result in incorrect economic signals being sent, particularly when the price set does not equal the marginal cost. Also, it can lead to large fluctuations in energy charges if the flow of investment is not constant. Further there is less incentive for producers to pursue efficiency measures since the rate of return in fixed, and there may be no facility to match risk with the return. Further, it is not clear how over capacity should be priced since it is of no immediate benefit to consumers. In the United States, regulators in some states prohibit so-called ‘non useful’ cost components, such as excess capacity, to be incorporated into the rate of return.

There are a variety of measures that can be used to overcome the disadvantages associated with historic cost recovery pricing. For example market oriented pricing initiatives could be introduced or efficiency enhancement initiatives promoted to increase the rate of return. Under incentive rate making, the tariff is indexed to inflation so that it doesn’t vary in real terms (often minus a percentage to allow for productivity increases). This gives an incentive to the energy producers to increase efficiency and therefore decrease their costs without impacting on the tariff they receive, thus increasing their rate of return. The system can be structured to allow for the benefit of increased production efficiency to be split between the producer and consumer.

MARKET PRICING

Market pricing involves the creation of a central market where bundles of energy can be traded between suppliers and consumers of energy at the nominated market price. Bids are accepted in the market from generators, and, in some markets, purchasers to produce or purchase electricity at a given price. Generally a merit order system is used to dispatch generation capacity. This leads to competition between producers and encourages efficiency in production since low cost producers are more likely to sell all of their production capacity.

In some electricity markets, producers receive the “system marginal price” for the electricity they supply to the system. The “system marginal price” is the price of the most expensive generating offer accepted. This systems provides an incentive for the producer to increase efficiency since cheaper production methods translate to greater producer profits. However, the consumer surplus is lower since consumers are forced to pay an inefficiency tariff’ on electricity production.

In theory, competitive free market prices will approximate the marginal cost of supply, promote the efficient use of capacity in the short-term and provide the correct market signals in relation to future investment capacity requirements. However, in practice other problems exist such as market dominance by large players who can remove competition and lower the economic efficiency of the system. Further, free market mechanisms are prone to periods of instability, and high levels of natural variability that can increase the uncertainty of investments in the long term. Supporters of market pricing argue that the problems of market pricing are solvable if the efficiency impediment can be removed.

Oligopolistic pricing:

A market is said to be oligopolistic if there are only a few sellers in the market with one or two major sellers controlling over a large share of the market. The remaining sellers may have the remaining of the market, but on an individual basis each controls a relatively small market share. In such a situation, the smaller sellers individually do not have enough power to have a significant impact on market behaviour affecting critical parameters like pricing, production or sales levels.

An oligopolistic market becomes a cartel if there exist arrangements amongst at least a few larger sellers, on key decisions in such areas as pricing, level of production and market shares.

Other features which tend to sustain an oligopolistic market appear to be associated with the oil sector. These interrelated features include vertical integration and the existence of both fiscal and non-fiscal barriers to entry. Most of the oil firms operating in developing economies are vertically integrated both internally and internationally.

Economic theory associating oligopolistic markets with a number of pricing behaviours, one of which – price leadership – has been adopted by the oil sector in developing economies since the deregulation. Price leadership is a practice in which one of the leading sellers ('price leader') takes a lead in determining and announcing price changes, with the immediately, with the remaining 'wait and see' sellers following immediately, or almost immediately, and announcing prices in line with the price leader's adjustment. Price leadership is said to be the most commonly practised pricing behaviour in an oligopolistic market.

The oil sector in many developing economies is characterised by a number of barriers which tend to restrain free entry into the market, thereby sustaining the oligopolistic structure of the sector.

DISCRIMINATORY ENERGY PRICING

Price discrimination can be used by suppliers as a means of extracting higher revenues by differentiating prices according to the consumer groups preferences (Schramm, 1985). Discriminatory pricing only refers to instances where different prices are charged relative to a single marginal cost of supply. It should be noted that differential pricing structures do not necessarily mean discriminatory pricing since differences in the quantity, timing, and location of deliveries will result in variations in the marginal cost of supply.

Price discrimination is often practised whenever it is possible to differentiate between user groups – such as residential, commercial and industrial customers. It is common in pricing schedules for electricity and natural gas systems, which can easily discriminate between customers through individually metered connections. Discrimination is less common for other types of energy supplies because of the difficulties of preventing resales and arbitrage, such as in petroleum products.

Price discrimination permits income redistribution, attempts to foster economic developments through low energy pricing to specific sectors, and can also be used as a tool for encouraging economically efficient development. It may also facilitate the operation of a plant with excess capacity since discriminatory pricing schedules may raise enough total revenue to cover the long-run marginal costs. This situation is common in developing economies where, for example, the construction of a new power plant is unlikely to reach full capacity until further economic development has taken place. To avoid the higher average cost of operating at lower capacity, the utility may use discriminatory pricing as a means of increasing revenue. Alternatively, the utility may search for additional markets and off load the surplus capacity at lower prices – implying that the primary market subsidises the secondary market.

PROMOTIONAL PRICING

Promotional pricing refers to the temporary under-pricing of energy supplies to selected customer groups at levels below the long-run marginal cost. The aim of promotional pricing is to increase market share, and thereby expand project utilisation at a faster rate. Promotional pricing, sometimes referred to as 'predatory pricing' is sometimes also used as a means of reducing the consumption of alternative energy sources.

In some instances, it may be reasonable and economically more efficient to price energy supplies not at the present low volume, high value, long run marginal costs, but at the expected average lifetime long run marginal cost that is based on a more rapid, immediate load build-up.

An important consideration in adopting such a pricing scheme is that the financial resources of the supplier need to be sufficiently large to cover the initial financial losses incurred. It is also imperative that demand forecasts are realistic, since massive losses can be accrued if consumers do not switch products.

GOVERNMENT PRICE INTERVENTION

The principal reason for government intervention in energy markets is to fulfil community service responsibilities and obligations. In relation to energy markets, these responsibilities and obligations range from improving social equity by providing low income concessions on energy commodities, to encouraging industry development and the creation of competitive markets. Governments may also have an interest in enforcing uniform tariffs so that all consumers have access to reasonably priced energy regardless of the cost of supply and ensuring that domestic energy users are not exploited by overseas energy utilities. The framework for accomplishing government responsibilities and obligations to the community is reflected in the energy policies that are adopted.

In terms of energy pricing, government objectives can generally be classified according to one of three groups; improving resource allocation efficiency, improving social equity and ensuring the financial viability of the energy sector (Pacudan, 1998). In some circumstances, conflicts may arise between these objectives and compromises will be required.

Traditionally most public and private enterprises in the energy industry have been required to undertake non-commercial activities to satisfy a range of government policies and social goals of an essentially non-commercial nature. Implementing price adjustment mechanisms is widely considered by governments as an effective policy tool. Policy makers argue that the benefits of applying these mechanisms, in terms of distributional welfare adjustments, outweighs the efficiency loss from the free market environment.

There are a range of policy available to governments to influence energy prices. Most of the mechanisms introduce economic and welfare costs on the community which are often hidden. From an economic perspective, approaches that promote transparency and minimise inefficient distortions are preferred. These measures include direct subsidies paid by governments or industry levies. Some of the policy tools available to governments, and the implications are discussed in the remainder of this section.

ENERGY TAXATION

Taxation of energy has been used by governments as a cost-effective method of raising revenues in situations where the demand for energy resources is relatively inelastic, that is, the higher energy price does not lead to a significant decrease in consumption. Taxing relatively inelastic goods, such as energy, also has the benefit that the distortionary effects of taxation, in terms of economic efficiency losses, are minimised.

Taxation is also used by governments to cover specific government energy related expenditure, such as facilitating transport networks and funding environmental programmes (effectively internalising the externality cost into the energy price) (Schramm, 1985), influence consumer behaviour, for example discouraging energy imports by implementing an import tariff (and thereby promote domestic energy sources) (Wirl, 1994).

CROSS-SUBSIDIES

Cross subsidies involve excess charges (prices greater than the cost of supply) being paid by some users in order to subsidise other users of the same product (who face prices that are less than the cost of supply). In effect cross subsidies represent a consumption tax and consumption subsidy for different energy consumers. Cross-subsidies can arise either as a result of different prices being paid for the same product by different users, or from the application of uniform prices paid for a product regardless of differences in the cost of supply.

Cross subsidies result in allocative inefficiency. Consumers whose consumption is taxed restrict their energy usage, even though they may value the consumption of additional units above the cost of supply. Conversely, subsidised consumers are encouraged to expand their energy use to the extent that the benefit they derived from increased usage is offset by higher costs of supply. The result is a decrease in allocative efficiency and a loss in welfare.

Industrial resource use is also altered by cross subsidies. Firms utilising subsidised energy more intensively gain an increase in competitiveness at the expense of other firms that are funding the subsidy through higher energy prices. Other inefficiencies may also result as the subsidised firms are subject to less competitive pressure. Nevertheless, governments have used cross subsidies as a means of encouraging economic development in specific sectors of the economy.

CONCESSIONAL DOMESTIC TARIFFS

Concessional domestic tariffs transfer income from a small number of high volume, low cost, industrial and commercial energy users to numerous small volume, high cost, domestic users. The aim of concessional domestic tariffs is to transfer income between tariff classes, such that higher income business owners and shareholders income is transferred to lower income domestic energy users.

Concessional tariffs can also be used by governments to encourage industry development in certain sectors of the economy. The funding of concessional tariffs can also be accomplished through cross-subsidisation, resulting in similar decreases in allocative efficiency levels.

UNIFORM TARIFFS AND CONNECTION SUBSIDIES

In many economies legislation has been passed requiring that all consumers are able to access energy at a 'reasonable' price. In the electricity industry for example, utilities may be prohibited from charging rural electricity users a higher tariff than consumers in urban areas. This requirement is despite the higher cost of providing electricity to few users in less populated areas, and reflects the equity concerns that all consumers should have equal access to essential goods.

There are a number of advantages and disadvantages associated with uniform pricing initiatives. Particularly, when implementing uniform tariffs, no account is taken of the income levels of the consumers and producers. Unless careful analysis is conducted on the welfare implications of the scheme, unexpected adverse impacts may arise and create vertical and horizontal inequity.

Similarly connection subsidies, where all consumers have equal access to supply regardless of location and cost, can result in economically inefficiency if more cost effective supply alternatives exist. For example, a requirement that all consumers are able to access a national electricity grid ignores a situation in rural areas where individual generation alternative, such as solar power generators, prove more cost effective.

SETTING LOWER RATES-OF-RETURN

Publicly owned energy utilities, particularly in the electricity sector, are sometime required to maintain lower rates of return and not exploit their producer surplus. Lowering the rate of return of public utilities is analogous to the public subsidising the consumers who benefit from the lower energy prices. This approach shares the problems of funding a cross subsidy in terms of cost transparency and accountability. For example, confusion may arise over the degree to which the rate of return has been lowered to directly benefit consumer, and to what extent it may indirectly benefit or disadvantage other parties.

DIRECT SUBSIDIES

Direct budget subsidisation involves government funding for selected beneficiaries directly from taxation revenue. In contrast to cross-subsidies, direct budget funding avoids the distortionary effects associated with incorrect pricing of services. Prices can be maintained at levels that reflect costs, so that efficient resource allocation results.

Additionally, direct budget funding improves transparency and removes the multiple objective problems characteristic of cross subsidies.

Direct budget funding can be implemented through two approaches: a producer subsidy paid to the energy enterprise for providing low cost energy services to the intended recipient, or alternatively a consumer subsidy paid directly to the energy consumer.

LEVIES ON USERS

Energy consumption levies can be imposed by governments to generate revenue for specific purposes. The explicit nature of levies increases transparency, and funds received can be explicitly directed to the purpose or reimbursed to selected recipients rather than hidden by a system of indirect cross subsidies.

ENVIRONMENTAL ENERGY PRICING

Incorporating an environmental component in to the final energy price charged to energy consumers has increasingly become common practice among developed economies. Adding an environmental component to energy prices recognises the significant costs associated with the production of energy, such as air pollution, land degradation and water contamination, and that these costs are not subject to the internal cost structure of the polluter. The additional environmental component to energy prices, can be applied directly or indirectly through taxes, price controls and the use of direct or indirect subsidies. By enforcing an environmental componen in their energy prices, such as an environment levy, policy makers aim to compensate society for the environmental degradation by charging an energy cost reflective of the 'real' cost of energy.

These external costs, known as 'externalities', are incorporated into a polluting utility's operational management structure – effectively 'internalising' the external cost. This approach is also referred to as the 'polluter pays' principle.

Generally speaking, environmental costs associated with energy production can be of three forms.

1. Costs that are economically significant, but not to the decision-makers. For example, water purification costs are more likely to be met by the water user rather than the polluter.

2. Costs that, although quantifiable, cannot be easily priced. For example, pricing for greenhouse gas emissions where no market for the emissions currently exists.

3. Costs that cannot be measured or quantified. Examples include prices for aesthetic goods, such as a view obscured by a power station.

By introducing environmental pricing practices, policy makers are effectively internalising these external costs so that they form part of the polluters decision making process.

There are a number of different ways that externalities can be internalised. These include:

- legislative control
- tradable permits
- offset programmes
- taxes

LEGISLATIVE CONTROL

Legislative control involves governments implementing unit specific limits through regulatory actions. In addition to setting minimum standards for pollution control, governments may also introduce requirements for particular actions to be undertaken to minimise the costs of environmental damage. Examples include completing environmental assessment and contractual clauses to return the land into its former condition at the conclusion of the project.

TRADABLE PERMITS

Tradable permit schemes have recently increased in prominence with the successful operation of the Sulfur-dioxide allowance trading program in the United States and Canada which aims to curb acid rain. Success in other applications, and the schemes apparent applicability to the control of anthropogenic greenhouse gas emissions under the Kyoto Protocol, have increased enthusiasm for tradable permits as a way of dealing with environmental externalities.

Under a tradable permit scheme, limitations are set to reduce the level of pollution. The level of allowable pollution effectively becomes a polluting right that can be traded among polluters. The traded nature of the ‘pollution permit’ requires that firms purchase permits while it is economic, which in aggregate results in a scheme that is economically and environmentally effective.

OFFSET PROGRAMMES

Offset programmes involve pollution reduction obligations in one area being ‘offset’, or cancelled, by abatement actions taking place in another area. The scheme has been recently popularised with the ‘activities implemented jointly’ climate change proposals where developed countries receive emission ‘credits’ by undertaking cross border emission abatement projects.

The advantage of offset programmes are mainly that it allows the pollution limitation objectives to be achieved at sites that provide the flexibility to the owner to determine the most cost-effective means to reduce overall pollution.

TAXATION

Taxation, or fees, levies and other charges, when applied to elastic commodities have the effect of reducing levels of demand through increasing the cost (price) faced by consumers. By taxing the quantity of pollution, governments encourage lower pollution and also accumulate revenue that can be used on anti-pollution schemes – such as reforestation.

Taxation policies can also be implemented across a broad base of polluting sources and, therefore, overcomes the ‘piecemeal’ flaws of other approaches.

There are two inherent problems with the use of taxation measures as a means of managing environmental problems. Firstly, there is no feed back mechanism that permits the policymaker to determine what the optimum level of taxation is. This requires that to achieve the optimum level of taxation, the policy maker must make continual refinements over time. Secondly, the suitability of taxation measures are restricted in markets where the price elasticity of the commodity is highly inelastic, since this would imply that regardless of the price changes (attributable to changes in the level of taxation) there would be a relatively small change in the quantity of pollution.

In energy markets there are many examples where externalities arise through the extraction, transportation and consumption of energy. These externalities can generally be divided into two groups according to the likelihood of the externality occurring. Externalities occurring in the usual operation of a business, such as environmental pollution from an open-cut coal mine and thermal pollution of a river adjacent to a power station, can generally be internalised by the polluting industry. However, some external costs may arise infrequently, such as an oil spill, meltdown of a nuclear reactor and explosion of a gas storage tank. The costs of these externalities are also often internalised as the polluting entity seeks insurance cover against these situations, and therefore may be reflected in the cost of energy.

Measurement of the externalities, and attributing the externality to a single source is often problematic. Measurement problems exist in terms of quantifying the pollution and determining the social, environmental and economic costs of the pollution. Several economic valuation methodologies have been developed to proxy some of these costs. However the costs of undertaking these valuations are no insignificant. Further, in some instances it is not always possible to directly link the pollution to the source, such as in climate change. Consequently, moral hazard and free-riding opportunities are exposed which may also need to be addressed.

REGULATORY ASPECTS TO PRICING

Energy prices are an integral part of energy policies throughout the APEC region. Energy prices are often used as an indicator of market performance, and also as a tool for modifying market behaviour, through controls, taxes and subsidies. It is commonly agreed that government regulation is required in some instances to control the operation of imperfect markets. The IEA (1998) provide examples of instances where some form of government regulatory intervention is justified. These include:

- NATURAL MONOPOLY – In energy market containing natural monopolies, such as in the case of local electricity distribution for many economies, prices charged for services often need to be closely monitored to prevent the monopoly service provider exploiting the excessive profits potential. In many instances, governments directly regulate, or impose operating controls, over energy prices imposed by non-government monopoly energy suppliers.

- SUPPLY SECURITY – Energy supply security can generally be divided into three risk categories; the risk associated with short term supply disruptions from supply and demand imbalances, the long term risk that market failure will result in inadequate investment to secure future supplies, and the risk of inadequate supply diversity in the event of major disruption. Energy prices offer one policy option to manage these risks, such as through regulatory provisions guaranteeing prices and eliminating market driven price variability.

- ANTI-COMPETITIVE BEHAVIOUR – Regulatory control of energy prices also limits the opportunity for dominant market participants to engage in anti-competitive market strategies, such as through predatory pricing initiatives to discourage new market participants.

- CONSUMER WELFARE PROTECTION – Most governments in the APEC region seek to provide consumer welfare protection to household customers, particularly the disadvantaged and charity organisations. In some instances, governments regulate prices to these consumer groups to negligible levels.

The degree of regulation, light-handed or heavy-handed, varies between economies depending on the objectives of the regulation. Relatively light-handed approaches exist in Australia and New Zealand, where the existence of anti-competitive institutions arguably acts as a deterrent to competitive market behaviour. Conversely, more detailed heavy-handed regulation in the United States natural gas sector aims to reinforce the fundamentals of competition law through explicit mechanisms designed to control the behaviour of natural monopoly transporters – including controls on pricing, handling of network access, and financial and operational performance regulations.

The regulatory approach adopted by different governments varies considerably with respect to:

- REGULATORY RESPONSIBILITY – A number of successful, and very different, regulatory supervision practices have been implemented in different APEC economies. At one end of the spectrum, specialised regulatory authorities have been created through legislation along with the clearly specified objectives. At the other end, these is no specific sectoral regulatory body however a broader competition commission assumes responsibility for the proper operation of the market. In the APEC region, there are no economies where the operation of the energy market is without some form of supervision.

- UNBUNDLING REQUIREMENTS – The unbundling requirement generally applies to vertically integrated energy companies, and aims to ensure that energy prices for each component reflect the cost of the service. By increasing the internal transparency, the existence of cross subsidies within a company can be examined. Unbundling ranges from requirements for separate accounting and managerial responsibilities for each business, through to the actual separation of the business from the corporate entity.

- CONTROLS ON PRICE AND RATE OF RETURN – Explicit price controls or guaranteed rates of return are often implemented by governments to accomplish a range of policy objectives. These controls are generally justified on the basis that they decrease risk during market establishment (before the market becomes fully competitive), increase market transparency for new market entrants, control the potential for a natural monopoly to extract excessive economic rent, and also to facilitate investment. The extent that governments regulate prices and rates of return also varies from direct intervention, through to conditions for pricing approval, and general oversight and monitoring.

- THIRD PARTY ACCESS REGIME – Market access tends to be based on either a regulatory approach and negotiated/unregulated approach. The regulatory approach generally specifies controls over market access, operations and financial stipulations. An unregulated approach generally allows the market to regulate itself, and is generally accomplished through a representative industry body which assumes responsibility for a formal code which proxies the objectives existent under formal regulation but also includes allowances for dispute resolution. Even in instances where the industry is self governing, it is common for the government to be in a position of ensuring that the industry self regulation is effective.

Case Study: Deregulation and Energy pricing, Experiences in Korea[1]

Price deregulation has been initiated in a number of industries in Korea, including the oil industry and power industry. In the oil industry, price deregulation has been in place since February 1998, and refinery business opened up from August 1998. In the power industry, there is easier entry into generation with the introduction of independent power producers (IPPs). By 2005, it is expected that more than 50 per cent of new power plants will be IPPs.

- Further, under the IMF conditions, the following tasks were also to be completed:
- Creating a deregulation agenda;
- Rationalisation of the oil and gas sectors;
- Revision of long term plans to reflect current circumstances.

Comparing energy prices in Korea with other economies in the region would indicate the relatively low final energy price. There are four types of taxes on energy in Korea – VAT (value-added tax), consumption tax, transport tax and education tax. The transportation tax is a specific amount added on to each unit of energy. Revenue generated from energy taxes makes up about 14% of total taxation revenue. This is much higher than most economies. Tax on oil products is current around about 89% and for gas around 54%. Transport tax revenue is specifically for road construction and similar projects.

There are a number of problems in the current energy tax system. These include complexities and inequalities, non-transportation tax system bias and the distortion of relative prices. Consequently, reforms have been advocated. Korean companies suggested reforms that simplify the current tax structure by combining all four taxes into a single tax, and also neutralising the revenue with expenditure to prevent distortions and inefficiency. Other reforms, such as the introduction of a carbon tax, have also being discussed.

It is expected that under the Taxation Reform Agenda Plan, oil prices would decline and equalise with other forms of energy. This is also likely to involve an increase in the price of electricity.

[1] This case study was prepared with a presentation made by Dr. Young-Seok Moon, Korea Energy Economics Institute, Korea, at the APERC Workshop on Energy Pricing Practices in APEC Economies held in July 1998, Tokyo Japan.

Case Study: Reforming Pricing of Oil Products in China[2]

TARGET AND PRINCIPLE OF REFORMING PRICING SYSTEM

The target of reforming the oil pricing system is to create a domestic market pricing system in line with international oil market price mechanism, while still subject to government regulatory supervision.

There are some main principles of the reform oil pricing system.

- To be beneficial to the preservation of the domestic oil resource and the development of the oil industry.
- To be beneficial to the technology progress, the management improvement and the cost reduction and lead to integrated development in the oil industry.
- To be beneficial to the creation of a unified, opened, competitive and in good order oil circulation system.
- To be beneficial to maintain relatively steady oil price bearing ability in the society.

PRICE OF CRUDE OIL PRODUCED FROM DOMESTIC ONSHORE

- The oil price will be negotiated by both of national onshore oil companies, the CNPC (China National Petroleum Corporation) and the SINOPEC (China Petrochemical Corporation), if the oil trade happens between both sides. If the negotiation cannot be settled, SDPC (State Development Planning Commission) will be asked to intervene and rule. The internal oil price will be set by itself if the oil trade happens between oil fields and refineries within a same group.
- The basic guideline of price negotiation is that the cost of domestic crude oil reached to refinery should be about equal to that at imported oil reached to the same refinery. In order to encourage refineries to use domestic produced crude oil, in regular condition, the price of domestic crude oil reached to refineries should be expected to a little bit lower than the total cost of imported crude oil.
- The settlement price (excluding tax) between purchaser and seller consists of the basic price and an agio (or a premium). The basic price will be set by the SDPC monthly in line with the FOB price and import tariff to similar reference crude oil price in the international oil market.

[2] This case study was presented by Mr. Ruichang Wu in the Japan-China Energy Seminar held in November, 1998, Tokyo, Japan. Original text was translated by Quan Tao and Zong-an Wang, Team Leaders of the Asia Pacific Energy Research Centre (APERC).

GASOLINE AND DIESEL RETAIL PRICES

- Instead of directly setting prices as done in the past, the Central Government will issue a reference (or indicative) retail price for gasoline and diesel. The SDPC will issue reference price for each province, autonomous region and the four municipalities. The retail prices will be carried out by the two retail monopolies, the CNPC and the SINOPEC, with a fluctuation range of 5% around the SDPC's reference prices.

- The principles to set the reference retail prices of gasoline and diesel are taking account of the cost of imported gasoline and diesel after tax, plus transportation cost from refinery to gas stations and surcharge of wholesale to retail. When the price change of gasoline and diesel is more than 5% in Singapore Market, the SDPC will adjust the reference retail prices.

- The interval of retail price adjustment by the SNPC and the SINOPEC within allowed 5% range on the basis of SDPC's reference prices should not be less than two months. The companies are required to report their adjustment to the SDPC before 10 days. If necessary, caused by market evolution, adjustment of retail prices within two months can be made on condition of SDPC's approval applied by the two retail groups.

- In principle, one province (region, municipality) has a uniform retail price for both gasoline and diesel. The two groups can set different prices in the marketing region, but each group should have the same retail price in a same marketing region. The gas stations, which do not belong to the two groups including those operated by foreign investors, should sell products on commission of the two and follow the stipulations of the group(s). The groups must take a joint reliability for the illegal activities of their commissioned gas stations.

CHAPTER 3

OVERVIEW OF ENERGY PRICING PRACTICES IN THE APEC REGION

OVERVIEW

A feature of the economies in the APEC region is the immense diversity measured in terms of the level of economic development, social and political systems, culture, climate and resource endowments. Similarly, there is a much variation between the energy pricing policies of individual APEC member economies, ranging from market pricing, to controlled pricing mechanisms. Different economies have different regulatory systems different policies and fiscal means, as well as different policy goals and energy pricing objectives.

This chapter presents a summary of survey results on energy pricing policies and practices for the APEC member economies, as well as three case studies. In conducting the survey APERC has endeavoured to cover all twenty-one APEC member economies, including the three new entrants, Russia, Peru and Viet Nam. However, due to the lack of information and data related to energy pricing, four economies, Hong Kong, China; Papua New Guinea; Peru and Singapore have not been included in the survey for this report.

This chapter is divided into four sections for energy pricing by energy source:

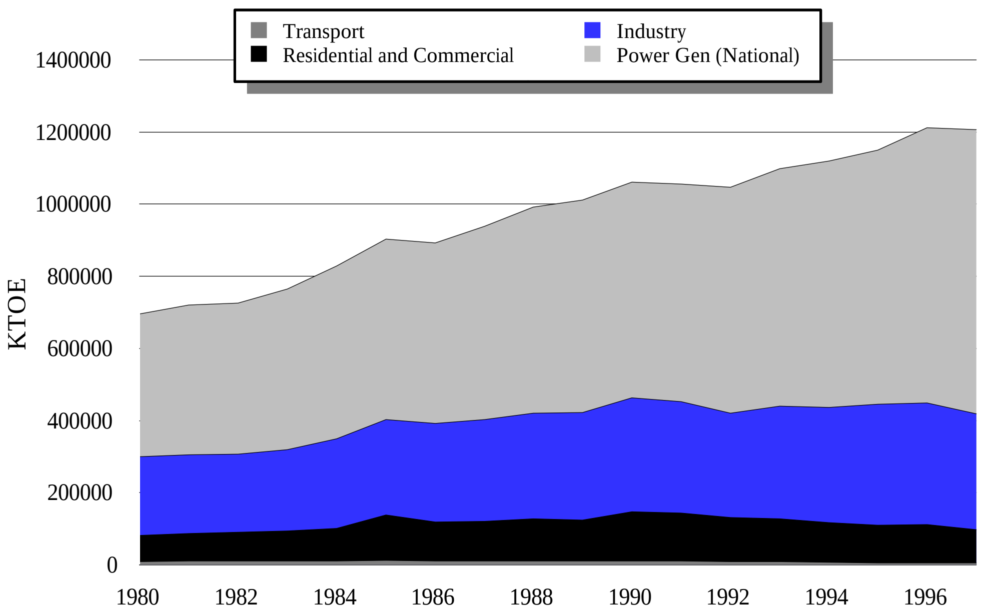
- Coal;
- Petroleum products;
- Natural gas; and,
- Electricity.

COAL PRICING PRACTICES

REGIONAL OVERVIEW

In APEC member economies, coal demand shows steady increase up to now. As Figure 1 shows, from 1980 to 1996, it increased at 2.5 per cent a year, mainly driven by power sector demand with annual increase of 4.9 per cent (1980-1996). Power sector coal demand accounted for 61 per cent of total demand in 1996. Also, industry sector, largely steel industry, contributes to the coal consumption growth too, showing 2.8 per cent growth (1980-1996) with 30 per cent share in total demand in 1996. By economy, China remained the largest coal consuming economy from 1980 to 1996, accounting for as large as 77.7 per cent of the total APEC region's coal consumption in 1996. China was followed by Japan (7.5 per cent) and the United States (4.7 per cent).

Figure 1 APEC Coal Demand by Sector
1980-1996

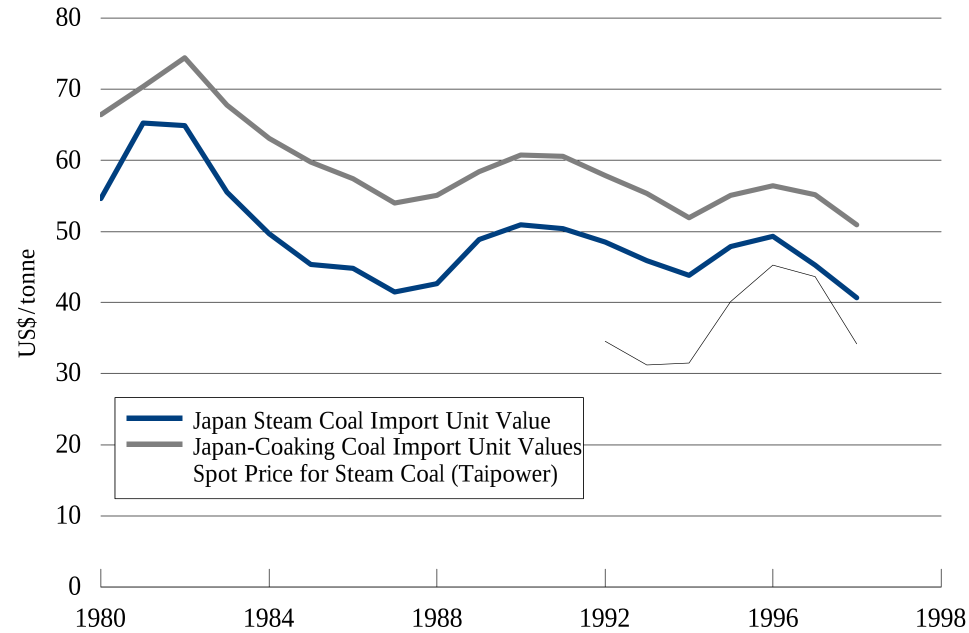


Source: IEA, *Energy Statistics of OECD and Non-OECD Countries*

Regarding coal pricing, a separate analysis is suggested on two types of price setting market in APEC member economies, namely international market and domestic market. With respect to international market, a "benchmark pricing", typically a negotiated price between Japanese steel mills and Australian producer for coking coal or between Japanese electric utilities and Australian producers for steam coal, prevails as a reference price in international market. However with the development of spot market, where coal price tends to be much lower recently, a benchmark pricing system is beginning to be influenced by spot market pricing, because buyers need to procure coal at lower price in the face of deregulation of electricity market or international competition. As for domestic coal pricing, in most of APEC member economies, coal price is left to the relevant negotiation. However, in some economies such as Indonesia and Viet Nam, ceiling price is placed for power generation because of social consideration.

Figure 2 shows the coal price trend in international market of long-term contract and spot market. From 1980 to 1998, there is an overall downward price trend in benchmark price as well as spot market. Up to 1995 and 1996, coal price showed some upward movement after the price bottom in 1993. Since then, it has been declining, particularly in spot market price. The changing pattern of transaction, mainly driven by Japanese electricity market deregulation and cost saving effort from Korean and Chinese Taipei's electric utilities, is considered to lower the coal price.

Figure 2 Coal Price Trend in Selected Member Economies
1980-1998



Source: IEA, *Coal Information 1998*

PRICE SETTING MECHANISMS: DOMESTIC COAL PRICING

Prices of coal products consist of various elements, such as:

- Mine mouth costs: labour cost, production cost, royalty and capital cost;
- Transportation costs: rail cost;
- Port costs;
- Retail profit margins;
- Taxes and levies.

As Table 2 shows, in most APEC member economies, domestic coal price is determined without government intervention, except for some member economies such as Viet Nam and Indonesia where they place a ceiling price for the coal used in electricity generation. The reason for setting a ceiling price is because of social consideration as to provide electricity at a low price to help lower income groups, while governments heavily subsidize coal producers to meet the difference between producer profit margin and ceiling price.

In economies such as Japan and Korea, where there is only limited volume of domestic coal resource, a ceiling price is placed for domestic coal, while government heavily subsidise coal mining industry because of security grounds as well as labour protection. In 1997, Japanese domestic steam coal price was 19,273 yen/tonne, on the other hand, Japanese imported steam coal price was 5,448yen/tonne. However, in both economies, the introduction of electricity sector deregulation that pressures electric utilities to lower fuel cost, seems to result in reducing the level of domestic production.

Table 2 Domestic Coal Pricing in APEC Member Economies

	Coal Pricing Mechanism	Coal Final Consumption (toe, 1997)	Comment
Australia	Market	6.58	Determined in a free market and negotiations between buyers and sellers
Brunei Darussalam			Coal products are not traded commercially.
Canada	Market	4.02	Determined in a free market based on quality of coal, calorific value, and sulphur content.
Chile	Market	1.38	With the removal of subsidies in early '90s, determined in the market
China	Market	358.5	Determined in a free market which establishes reference prices in Qinghuan Dao and Shanghai ports
Indonesia	Market	2.50	Determined either in a spot market or negotiation between buyers and
Japan	Regulated/ Market	38.66	Domestic price is regulated by government
Korea	Regulated/ Market	17.97	For domestic anthracite, a ceiling price is placed on because of social reasons
Malaysia	Market	0.74	
New Zealand	Market	0.88	No subsidies are placed on coal. All coal is sold by competitive contract.
Philippines	Market	0.64	Determined in free market. For instance, National Power Corporation solicits for bids for fuel requirement in coal fired power plants.
Russia	Market	73.15	Liberalised in July 1993
Chinese Taipei	Regulated/ Market	9.58	For domestically produced coal, government maintains a ceiling price for social reasons.
Thailand	Market	3.97	Domestic price reflects the prevailing world price.
USA	Market	36.06	Determined in the free market based on the quality of coal, calorific value, and sulphur and ash contents
Viet Nam	Market	2.22	Basically determined in market. However, as for power generation, price ceiling is placed because of social consideration.

Source: APERC Survey, APEC Energy Database

Case Study: Reforming Pricing of Coal Products in China

Up to January 1994, a dual pricing system for coal operated in China comprising of the 'Allocated coal price' and 'Free market coal price'. 'Allocated coal' means the coal production volume is allocated through the annual negotiation of producers, large customers, and central and provincial government agencies. Allocated coal receives significantly low prices, while the volume of production exceeding production quotas, set by a plan, receives higher prices. "Free market coal" was produced primarily by small township mines and sold at negotiated price if there is available transportation such as rail, road and river shipping (IEA, 1997). If there is not, production was sold to the state mining bureaus.

The dual pricing system led to the inefficient resource allocation of coal partly due to the size of country and logistical bottlenecks. Prices varies widely among the region, hence it distorted the market, affecting the investment in transport and coal utilisation technology.

Under these circumstances, in January 1994, the dual pricing system was abolished and measures to reduce inefficiency were implemented. For instance, subsidies to the coal industry were reduced significantly from USD 0.7 billion in 1993 to USD 0.5 billion in 1994 in an attempt to eliminate subsidies by 1996.

With the abolishment of dual pricing system, it was expected that more efficient resource allocation would be made possible. However, during the time when dual pricing system was implemented, there were shortages of, for instance, rail transport capacity, that takes time to be developed largely in an attempt to enjoy the benefit from free market. Therefore, transport will remain to be a major impediment to the ability of supply to match demand in the market.

PRICE SETTING MECHANISMS: INTERNATIONAL COAL PRICING

There are two broad ways of setting international coal prices in the APEC region: long-term contract pricing and spot pricing. There are, however, many variances.

CONTRACTUAL ARRANGEMENTS

Long-term contracts: "benchmark pricing"

In the Asia-Pacific energy market, long-term contracts with annual price reviews were commonly used by suppliers and customers who trade large quantity over the long period. However, the price reviews and revisions became more frequent than annually. Price negotiations by large customers and suppliers provided a 'benchmark', or reference, for regional prices negotiations. For example, annual prices negotiated between Japanese steel mills and Australian and Canadian coking coal suppliers were influential, as benchmarks, in the negotiation of other regional coal contracts.

Until 1996, Japan steel mills took annual negotiations with suppliers. Then the settled price was taken to be as the "benchmark price" for the export to other economies such as Korea and

Chinese Taipei. For instance, a Korean steel maker POSCO and a Chinese Taipei steel maker, China steel have normally followed the price set with the Japanese steel mills.

In the Asia Pacific market, benchmark steam coal prices were kept in close relationship with the semi-soft coking price.

Spot-contracts

Spot contracts can be the purchases ranging from single cargo to several cargoes. However, they do not necessarily involve a long-term relationship. Major buyers on spot market are located in south and south-east Asia, such as China Light and Power in Hong Kong and Taipower, with utilisation of coal for mid-load basis. Recently, an increasing number of transactions are conducted among the major utilities under spot contracts.

SHIFT AWAY FROM BENCHMARK PRICING

The benchmark pricing was not necessarily operated efficiently. It tended to be settled at the average price that covers all producers' production cost[3]. This leads to maintaining less efficient producers where they pay high labour cost that could be replaced by producers with much lower cost[4].

Recently, in recognition of this, a greater degree of competition is encouraged between Australian producers, for instance. In the long run, competition will help reduce the production cost.

Also, recognition of inefficiency through benchmark pricing leads to encouraging spot market transactions. Japan pays high price through benchmark pricing for the supply security consideration. However, instead of buying high priced coal under benchmark pricing, providing security premium to spot market price may ensure security of supply. For the purpose of procuring from relatively cheaper supply source, from 1996, the Japanese steel mills abandoned benchmark pricing.

Also, from 1998 the Japanese electric utilities abandoned benchmark pricing. Since Japanese deregulation of electricity sector took place in 1996, allowing the entries of IPPs, Japanese electric utilities had to lower the resource cost. As Table 3 shows, the share of tenders increased considerably, while the share of transactions with benchmark pricing decreased.

The shift away from benchmark pricing continues to provide a range of ways of price settlements between Australian sellers and Japanese power companies for all grades of coal. Different prices continue to prevail, even between the same buyers and sellers for different volumes of coal[5].

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[3] It is also pointed out that Australia sells coal products to Japan at relatively low price in considering its quality and supply security, because of the buyer power exercised by Japanese side.

[4] IEA 1997, *International Coal Trade – The Evolution of a Global Market*

[5] IEA 1999, *Coal Information 1998*

Table 3 Type of Contract in Japanese Electric Utilities

	FY 1995	FY 1996	FY 1997	FY1998 (estimate)
Long-term with benchmark	73%	72%	72%	22-58%
Long-term and option	0%	0%	0%	50-14%
Tender (short- and long-term)	6%	8%	12%	12%
Spot	21%	20%	16%	16%

Source: MITI, Coal Note (1999)

Along with the Japanese shift away from benchmark pricing system, a shift away from contract purchases to the spot market also seems to be happening in Asian coal market. It implies that coal producers in Australia and other exporting countries will be under increased pressure to reduce mining costs in order to maintain current rates of return. It also means that less competitive suppliers, such as the United State, will find it difficult to increase or maintain coal sales to the region[6].

PETROLEUM PRODUCTS PRICING PRACTICES

REGIONAL OVERVIEW

Pricing mechanisms for petroleum products in the APEC member economies range from market pricing to controlled pricing ones, depending on the industrial structure of the domestic oil sector, market environment and the government policy.

In the developed APEC economies the oil industry is privately owned and fully deregulated to facilitate the operation of a competitive and free market. Hence, prices for oil products in those economies are determined by market mechanism with minimal government interference. Among developing economies, the Philippines liberalised prices for petroleum products in February 1997. Recently, Korea also removed the government intervention in the oil sector, and the price for petroleum products, except for LPG, were fully liberalised since February 1998.

Some economies are under a gradual transition process from the regulated pricing to market pricing mechanism with specific schedule. For example, Chinese Taipei and Thailand have both commenced liberalisation programmes and market forces are increasingly determining energy prices. Chinese Taipei partially liberalised petroleum product prices, such as LPG, jet fuel and fuel oil, from the beginning of 1999, aiming to complete the liberalisation of the oil sector by 2000. Recently, in Thailand, a floated energy price system has been introduced to create a mechanism where gasoline, diesel and LPG can be sold at the same price nationwide. The energy price is easily adjusted to reflect market forces: competition and international trading.[7]

Oil product prices remain tightly controlled by the government in some developing economies in the APEC region, such as Brunei Darussalam, China, Indonesia, Malaysia and Viet Nam, where the domestic oil industry is characterised by the government monopoly structure.

[6] IEA, *Coal Information 1998*, 1999.

[7] In Chinese Taipei, in order to systemise oil price adjustments, the government launched a floating oil prices policy and has reviewed prices weekly since March 1998.

For example, in Brunei Darussalam and Indonesia, consumer prices for petroleum products are highly subsidised by the government for social policy considerations.

PRICE-SETTING MECHANISMS

Prices of petroleum products are generally determined by various components accounting for costs, taxes and profit margins of oil companies and retailers, which include:

- Cost for crude oil procurements (production and imports);
- Refinery production costs and margin;
- Taxes and other levies;
- Transportation costs; and;
- Retailers' profit margin.

The cost factors and taxation are important in determining the level of petroleum product prices. However, pricing mechanism for the petroleum products are significantly influenced by the industrial structure and market environment of the oil sector in each economy, such as the number of market players (refineries), the market size, and the government regulation and policy.

As shown in Table 4, market pricing mechanism for petroleum products tend to be adopted by developed economies in the APEC region, where demand is relatively stable at a high level and there are a sufficient number of privately owned refineries operate to facilitate market competition. In economies with a growing oil market, such as Korea, Chinese Taipei and Thailand, the pricing mechanism is becoming increasingly market-driven.

In many developing economies in the APEC region, the production and distribution of oil products are still monopolistic or oligoplistic in the sense that there is one (mainly a state enterprise) or only a few oil companies in the market. In such cases, the government regulates prices for petroleum products either directly or indirectly. The main reasons why government controls prices of petroleum products include the strategic importance of oil to the economy and the issues of equity and welfare of consumers, particularly to help lower income groups.

This empirical observation implies that the introduction of market pricing mechanisms is only feasible in a mature oil market and with an established investment environment, and that the benefits of market pricing do not simply result from a government lifting petroleum product price regulation. Since investment to build refinery facility and retail outlet of petroleum products is capital intensive and there exist economies of scale in the oil sector, there can hardly be a new entrant in the sector without having a sufficient amount of demand secured. This factor alone explains why a number of firms have failed to initiate investment in the oil sector in some developing economies despite the government's liberal stance.

Table 4 Oil Industry and Pricing in the APEC Member Economies

	Oil Pricing Mechanism	Oil consumption p. c. (TOE, 1997)	Ownership Structure	No. of Major Oil Companies (refineries)
Australia	Market	1.99	Private	9
Brunei Darussalam	Controlled/Subsidised	1.50	State-owned	1
Canada	Market	3.05	Private	4
Chile		0.74	State-owned	3 under ENAP
China	Controlled	0.15	State-owned	2
Hong Kong, China		0.64		
Indonesia	Controlled/Subsidised	0.21	State-owned	1
Japan	Market	2.14	Private	14
Korea	Market	2.28	Private	4
Malaysia		1.08	State-owned	1
Mexico		0.82	State-owned	1
New Zealand	Market	1.62	Private	1
Peru		0.32		1
Philippines		0.23	State-owned	3
Russia		1.06		38
Singapore		6.55		4
Chinese Taipei	Transition to market	1.54		3
Thailand	Transition to market	0.61		5
USA	Market	3.18	Private	22
Viet Nam	Controlled	0.08	State-owned	1

Source: APERC Survey, APEC Energy Database, USDOE/EIA Website

In addition to the competitive market environment for the oil sector, the liberalisation of export and import of petroleum products is also an important factor in supporting the operation of market pricing mechanism. Depending on the efficiency of the domestic refining sector, domestic petroleum product price may be higher or lower than the import prices of the same products, so that domestically produced petroleum products can be competitive or less competitive internationally. In New Zealand, where there is only one domestic refinery, the liberalisation of oil product imports has resulted in a competitive market economy.

TAXATION ON OIL PRODUCTS

The practices for taxation on petroleum products are different across economies in the APEC region. In general, petroleum products are taxed in several ways, and types of taxes imposed on petroleum products include duties on imported crude oil and associated products, income taxes on producers and refineries, value-added taxes, excise taxes, and other surcharges and levies aimed at achieving particular purposes.

- Import duty: imported crude oil and petroleum products may be subject to a customs duty.
- Excise tax: domestic refineries may be subject to an excise tax.
- Sales tax and value-added tax (VAT): wholesale or retail sales may be subject to a sales tax or a VAT.

There are two basic tax rates that can be imposed. Specific taxes are imposed on the quantity of the product sold, while ad valorem (percentage) taxes on the value of sales. Choosing to impose a specific or ad valorem tax depends on the particular reasons for the tax.

There are a complex variety of reasons for taxation on oil products. The taxation on oil products is a reflection of various reasons, including attempts to internalise some externalities such as emergency stock holdings and to improve the income distribution through the fiscal system;

- To raise revenue with low administrative costs;
- To discourage wasteful consumption of petroleum products and conserve energy;
- To reflect the externality cost into prices to ensure more efficient use of resources; and,
- To improve the distribution of income.

Taxes imposed on the consumption of petroleum products in general have proven to be a reliable source of raising revenue. Targeting the inelastic demand for petroleum products, the government raises revenue without much distortion in resource allocation. In most economies, some petroleum products, especially motor gasoline, are considered suitable for levying high taxes. In developing economies it generally accounts for about 7 to 30 per cent of total revenue and is equal to between 1 and 3.5 per cent of GDP (IMF, 1994)[8]. Particularly, petroleum taxes provide a higher proportion of total revenue in the oil producing and exporting economies.

An economy that is a net importer of petroleum products and is faced with a foreign exchange shortage may resort to petroleum taxation in order to restrain its consumption and conserve foreign exchange. Some economies may seek to achieve enhanced energy security through conservation by raising the cost of petroleum products in relation to other domestic energy sources. To meet this objective, the government can change a premium on petroleum consumption in the form of an excise duty. Major petroleum exporting economies may also raise taxes on petroleum products in an effort to constrain the ability of oil producers to influence international crude oil prices.

Some oil taxation is justified as a method of charging for costs or externalities that flow from petroleum consumption. An externality arises when an activity by one agent imposes costs on others that are not reflected in the prices facing that agent. Thus, there may be an incentive to use roads excessively in relation to their construction and maintenance costs as well as congestion costs and to impact on the natural environmental to a degree that is excessive from social perspective. Taxes reflecting the social cost of resources that go uncharged can serve as prices for the use of resources and thereby eliminate the market failure. The most appropriate form of taxes used to take account of social costs will be specific rate taxes, which are based on the quantity of fuel consumed. Ad valorem taxes are inappropriate because the value of the fuel does not necessarily bear any relationship to the amount of road use or to the environmental cost of emissions from the use of fuel, both of which depend on the quantities of fuel used. The extraordinarily high tax rates on gasoline in a few economies appear to be related to giving an unusually high weight to pollution or revenue considerations.

[8] International Monetary Fund, 1994, "Taxation of Petroleum Products: Theory and Empirical Evidence", IMF Working Paper WP/94/32.

Oil taxes can have considerable implications for the distribution of income particularly in developing economies, where oil products are often used for heating, cooking, lighting, and transportation, and constitute a significant share of the consumption basket of the poor. Unless the consumption by the poor of these products like diesel and kerosene is explicitly considered, petroleum taxes can be regressive and adversely affect this segment of the population. In contrast, the consumption of motor cars, and, thus, motor gasoline, has been found to rise rapidly with household incomes in developing economies, and its taxation can be considered to be a form of excise on luxury consumption which improves the distribution of income. A case for income distribution through oil taxation can be seen by the fact that the government fiscal revenues; which are effectively transfer payments via the government from one group of people to others; are used, among other things, to provide other services such as health and education to the poor people. Another fiscal dimension of income distribution relates to the skewed taxation of various petroleum fuels: taxes on gasoline remaining much higher than those on other products.

There is a wide variation of petroleum tax rate levels and structures across the APEC member economies and over time. In practice, many economies impose different tax rates for different oil products to achieve social, environmental and economic policy objectives. In general, most APEC economies charge a relatively lower tax rate on petroleum products consumed by the majority, such as kerosene, fuel oil, LPG and diesel oils.

SUBSIDISATION AND CROSS-SUBSIDISATION

Petroleum products are often subsidised as a policy instrument in industry and trade, in both developing and developed economies. More fundamentally, it has been emphasised that the provision of energy products and services at below the market price has been one of the economic policy instruments used to address welfare and poverty issues in many developing economies. These practices can be observed, for example, in Indonesia and Brunei Darussalam. However, it is not clear how much of the subsidy on petroleum products goes to lower income groups. A large part of the subsidy, apparently, is leaking out to relatively well-off urban households. In many petroleum producing economies, the marginal production cost is significantly below world market prices, at the same time the domestic prices of oil products are set well below world market levels, thereby providing an implicit subsidy to domestic oil consumers.

In order to avoid the under-pricing problem caused by subsidies, a tax should be set so that the ex-refinery price is at least equal to the opportunity cost, the price that could be obtained if the product was exported on the world market. Such a policy is deemed appropriate to maximize gains in economic efficiency and to assist in mobilising revenue resources. The rent extracted by the government through such taxation can then be redistributed and targeted to promote socially desirable objective. This is far more efficient than distributing the rent to the domestic oil consumers by under-pricing petroleum.

However, a lower level of prices does not necessarily imply subsidised prices. An economy having relatively lower social overhead costs for land, labour, and the use of infrastructures, for example, can set the lower level of petroleum product prices, compared with the other economies.

As discussed in Chapter 2, cross-subsidisation emerges from a market situation in which there exist price differentials, for a product or similar products, which are not associated with differences in either product quality or costs. Necessarily, certain products are sold at prices above their economic values, while others are sold at prices lower than their values. Thus, for the business to break even, the resources generated from the higher prices compensate for those gains foregone owing to the lower prices. Price differentials can have two major causes. The first is a deliberate government discriminatory taxation/pricing policy designed to achieve an equitable income distribution objective. The second is discriminatory pricing behaviour practised by powerful market participants.

It is clear that this policy depended on a market situation where the overall profit margin of a company supply variable products is regulated, so that a depressed margin on one product could be picked up through a high margin on another product – a single vertically integrated industry. Under this situation, the governments desire to ensure adequate supply of some oil products, kerosene for example, to the rural areas and to the relatively poor household sector at relatively low costs. Also, some non-household markets for petroleum products, such as electric power generation sector, are taking advantage of this discriminatory pricing policy in many economies.

Table 5 Comparison of Prices of Oil Products among APEC Economies
$US/litre; 1997

Economies	Regular Unleaded Gasoline (US$/litre)			Automotive Diesel (US$/litre)			Kerosene (US$/litre)		
	Price	Tax	%	Price	Tax	%	Price	Tax	%
Australia	0.54	0.31	58	0.54	0.31	58			
Brunei Darussalam				0.21			0.13		
Canada	0.43	0.20	47	0.40					
Chile	0.56			0.35					
China	0.28			0.26					
Hong Kong, China									
Indonesia	0.29			0.12			0.10		
Japan	0.86	0.48	56	0.66	0.28	43	0.41	16.46	4
Korea	0.88			0.40			0.39		
Malaysia	0.39			0.24			0.20		
Mexico	0.39	0.05	13	0.30	0.04	13			
New Zealand	0.60	0.28	47	0.32	0.04	12			
Papua New Guinea									
Peru	0.51			0.45					
Philippines	0.34			0.26			0.24		
Russian Federation									
Singapore	0.15			0.15			0.16		
Chinese Taipei	0.59	0.25	43	0.41	0.15	37	0.43		
Thailand	0.32			0.30		3	0.36		
United States	0.33	0.10	30	0.31	0.12	39	0.28		
Viet Nam									

COMPARISON OF PRICE AND TAX LEVELS IN APEC MEMBER ECONOMIES

Table 5 and the following figures show the levels and trends of petroleum product prices for selected APEC economies measured in US dollars per litre. Higher prices of petroleum products are observed in Japan, Korea and Chinese Taipei in the APEC region. This is not surprising since those economies are oil importing economies and higher rates of taxes are imposed on the petroleum products. Considering the order of economies represented, we observe at the other end lie Mexico, Indonesia and Malaysia, the oil exporting economies.

Closer examination also reveals a range of non-energy related influences. These include the depreciation of the yen relative to the US dollar from 1995, the appreciation of the Australian dollar relative to the US dollar during 1996, the effects of the 1997 Asian economic crisis. The transmission of these influences to energy markets has taken place primarily through energy pricing.

Figure 3 APEC - Unleaded Regular Gasoline Price
US dollars/litre

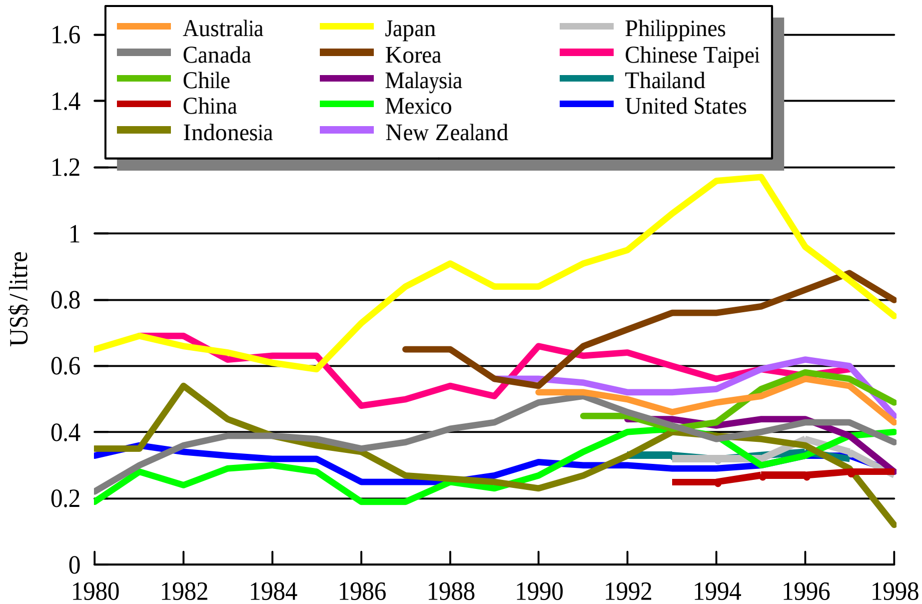


Figure 4 APEC – Automotive Diesel Fuel Price
US dollars/litre

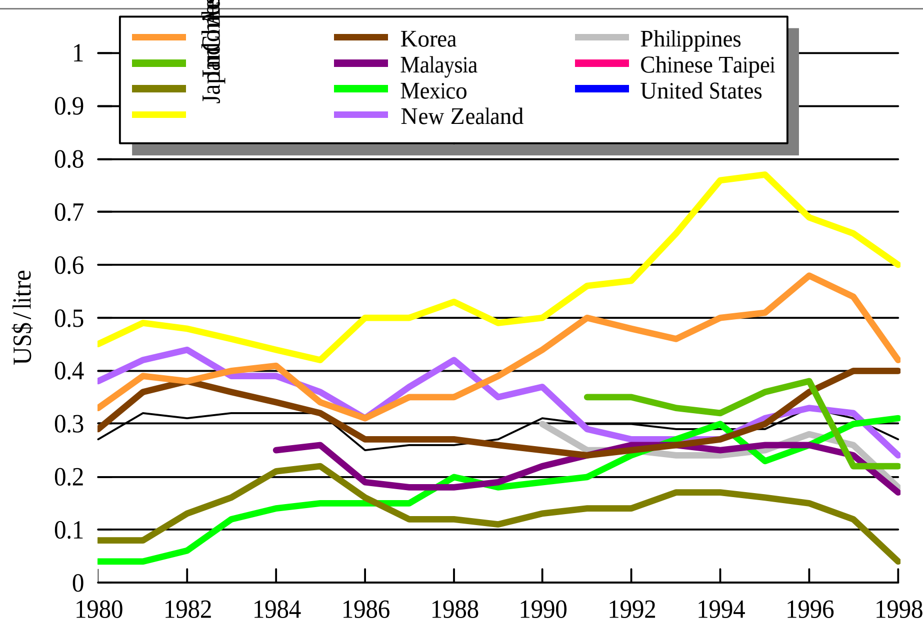
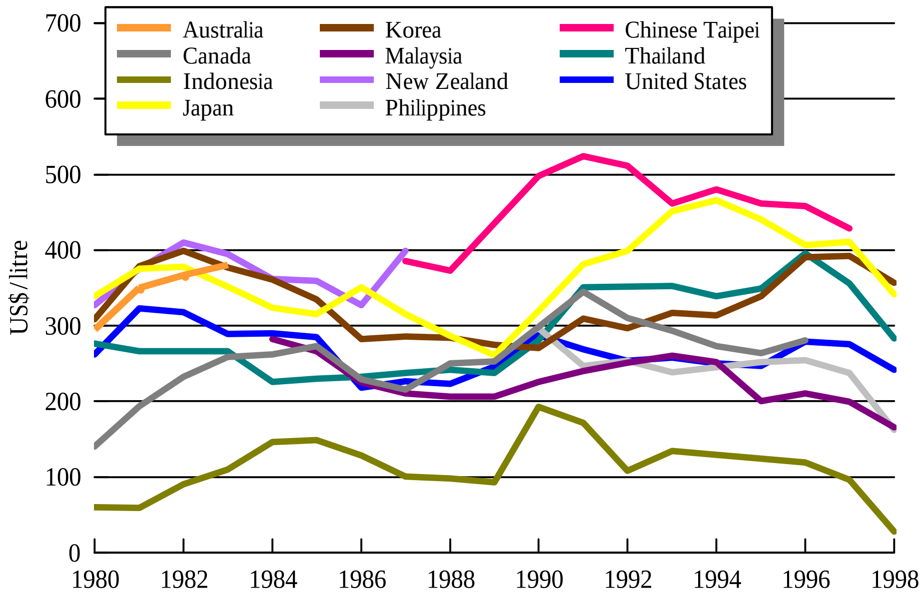


Figure 5 APEC – Light Fuel Oil Price
US dollars/litre



NATURAL GAS PRICING PRACTICES

The determination of domestic natural gas prices differs by economy in the APEC region, reflecting its demand and supply balance, cost of supply (locally and internationally), prices of competing fuels such as oil and coal, and the concerns for social welfare in the particular economy. As demand for natural gas is expected to increase throughout the APEC region, and as the exploration and development of natural gas reserves is expected to be more active, the role of natural gas is becoming important. The wellhead price affects the profitability of the gas development and becomes a factor in determining the producer price. Through the international trade, the demand in an importing economy can influence the exporters gas price. Further, transportation costs, government regulations and interventions, and the structure of the gas industry are among the factors determining the consumer price of gas.

The trading types could influence the natural gas pricing as well. International trades within the APEC region takes form of shipping of liquefied natural gas (LNG), especially trade between Southeast Asian gas exporting economies and Northeast Asian importing economies, and pipelines in most economies in the Americas and some in other parts. 75 per cent of global LNG trade takes place in the Asia-Pacific region.

While natural gas sector reform has been taking place in some economies in the APEC region as alternative to monopoly, the difference exists as to the level of the competitive market among economies, as seen in the next section.

NATURAL GAS REFORMS

Natural gas reforms have been pursued in a number of economies. They are often carried out as part of economic reforms in general and, sometimes, accompanied by reforms in electricity sector. The benefit of more competitive market for natural gas is shown in the increased range of services available to end-users and lower prices. Average gas prices to end-users have held stable or fallen, while volumes delivered have increased. The apparent success of these reforms has incited other economies to pursue similar policies. Canada and the United States were the first economies to initiate them in the late 1970s and early 1980s. Both economies are in the process of restructuring the wholesale gas industry, and are considering extending competition in the retail market to include the smallest consumers. Some other economies that are pursuing extensive natural gas sector reforms include Australia and Thailand.

Although there are similarities with electricity and other network industries, gas market differs from other commodities in the following ways.

- Its transportation is in most cases a natural monopoly; the supply of gas to end users will always involve an element of monopoly even in a competitive market.

- Gas prices in a competitive market may differ significantly in the short and long run; while in the short run, prices will be determined by the marginal value of gas in end-user markets, in the long term, prices will tend to fluctuate around long-run marginal cost.

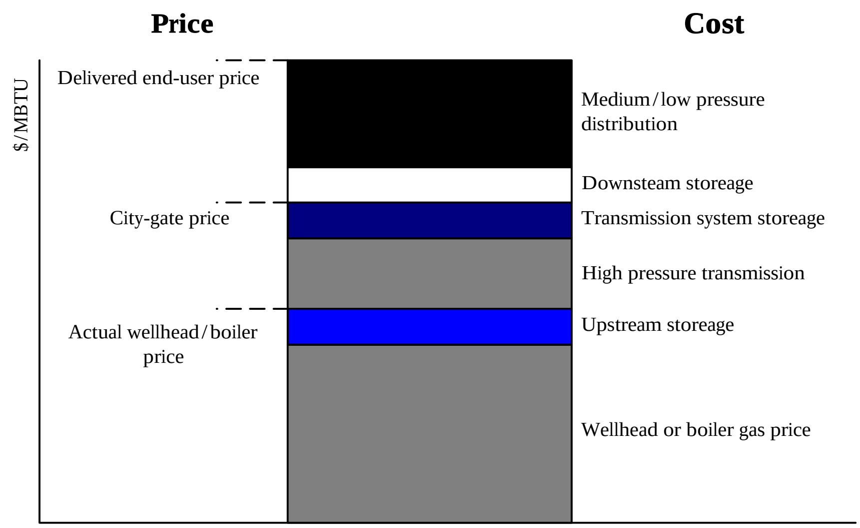
- End-user demand for gas for heating (mostly in the residential and commercial sectors) and to some extent in power generation is strongly correlated to the weather.

- Most of the customers are not contestable (they do not have alternative to using gas), so that overall demand may be price inelastic in the short run.

Transportation cost is important in most gas markets, because it is highly capital-intensive and expensive relative to the cost of the commodity itself. While retail prices have been deregulated in some markets, transportation services remain regulated by the government.

The cost breakdown of end-user gas price can be illustrated in Figure 6.

Figure 6 Cost Component of Average End-User Gas Price



Source: IEA, 1998

Basically, there are two market models practiced as alternatives to the basic monopoly structure in the natural gas market, namely pipeline-to-pipeline competition and mandatory third-party access to the industry network. The last model can further be separated into wholesale or bulk market competition and full retail competition.

Australia, Canada, New Zealand and the United States are the economies in the APEC region that practice wholesale competition, and Mexico is known to have a plan to do the same. Other economies in the APEC region are still in either monopoly or pipeline-pipeline competition.

Models of Natural Gas Markets

MONOPOLY

Transmission and distribution are considered to be a natural monopoly. Therefore, transportation service charge needs to be controlled to prevent excessive profits for the service provider.

PIPELINE-PIPELINE COMPETITION

Two or more high-pressure transmission pipeline companies deliver gas to the same regional market, to compete for sales to bulk industrial customers, power generators, and local distribution companies (LDCs). True competition is limited, since the sales are usually under long-term contract.

WHOLESALE COMPETITION

Non-discriminatory third-party access to the high-pressure transmission system is compulsory; transportation service is separated from the gas sales activities, and marketing companies compete for sales to bulk industrial customers, power generators and LDCs. Here only large customers can choose their supplier (contestable).

FULL RETAIL COMPETITION

Mandatory third-party access is extended to cover distribution networks, so that small customers (end-users) also become contestable. Transportation and sales are unbundled at all levels.

OTHER ISSUES IN NATURAL GAS REFORMS

Transparency is a critical issue in pricing practice. In Australia, although natural gas reforms share a common ultimate objective with electricity reforms, an issue of lack of transparency in the gas pricing relative to the electricity pricing has been raised. The concern was expressed that it would discourage the development of an integrated energy market.

TERM CONTRACT PRICES AND SPOT PRICES

Both medium- or long-term contract prices, which are associated with medium to long term natural gas supply, and spot prices, which are used in the short-term transactions prevail in the market. Medium- or long-term contracts are more used in Canada (and mostly in North America) and Chile. However, in Canada spot market takes place as a response to the risk over the medium- and long-term contract. In North America the spot prices are often influenced by the weather condition, which determines the gas demand, as evident in the winters in 1995, 1996 and 1999, and by the difference of delivery point.

Those factors will have an effect on the producer price as well as on the consumer price on the end-use side.

SOCIAL OBJECTIVES IN THE PRICING POLICY

In some APEC economies, concern over social issues is reflected through government intervention in natural gas pricing. The intervention aims to meet social objectives by subsidising gas prices, such as in Brunei Darussalam, Indonesia, Korea and Chinese Taipei. Cross subsidies differentiate consumer groups in these economies, and the extent of the subsidy is reflected in the variability of prices between customer groups. For example, the wholesale gas price to fertiliser industry in Indonesia is subsidised so as to provide Indonesia's lower income farmers with inexpensive fertilisers, that in turn ensures self-sufficiency in rice production. The application of subsidy illustrates the government intervention on the gas pricing setting.

OTHER FACTORS IN THE DETERMINATION OF GAS PRICES

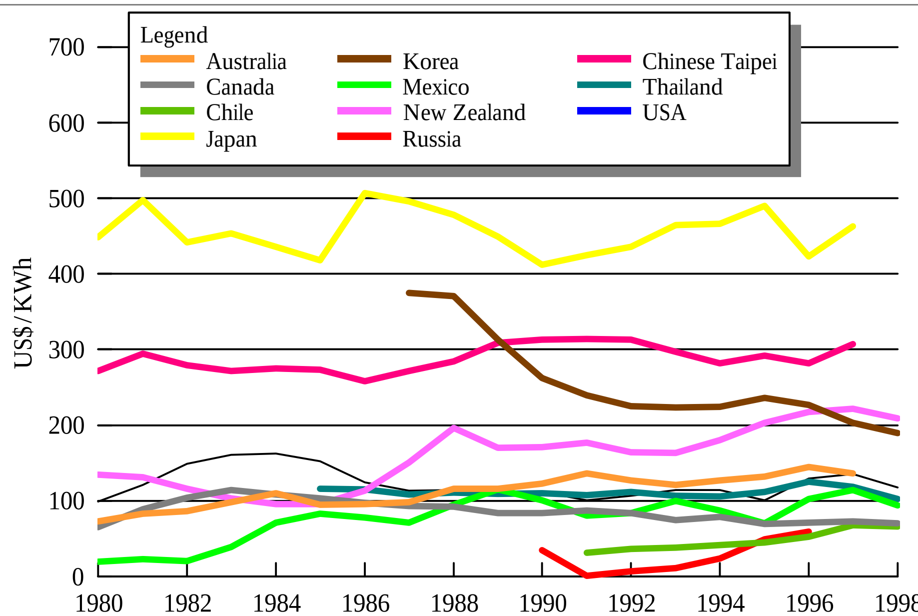
In some cases natural gas base prices are indexed to prices of oil products or simply crude oil, as in a monopoly, where the gas pricing sometimes uses netback value approach. Netback value is used in the natural gas pricing in Indonesia and Malaysia.

Other factors affecting natural gas prices are: the region of supply or use, designated use, purification and transportation cost, negotiation positions between suppliers and buyers (especially for power generation), and foreign exchange rates.

NATURAL GAS PRICES IN SELECTED ECONOMIES

Figure 7 shows trends of natural gas consumer (nominal) price in some APEC economies. At the beginning of the last decade, Japan, Korea and Chinese Taipei, which depend upon LNG, had the highest gas prices. Japan and Chinese Taipei have stayed at the same level while Korea experienced a considerable decline to less than 200 US$/toe.

Figure 7 Natural Gas Prices in Selected APEC Member Economies
US$/KWh; 1978-1998



Source: APEC Energy Database

ELECTRICITY PRICING PRACTICES

OVERVIEW

Electricity has been a major driver for the industrialization of the most APEC economies in the course of the last century. Its role has been increasingly important as major technology development in all sectors of an economy has its basis on electric power. More industrial processes are electrified and motorized, while electric appliances replace household labour and some fossil fuel equipments. As a result, the share of electricity consumption in terms of total final energy has been rising in most economies throughout the APEC region.

As rightly pointed out by Rosenburg (1998), the dynamics of current technological development is likely to extend the present trend of rising electricity share to an indefinite future, which incorporates semiconductors, computers, telecommunications and information technologies. Also in the household sector, income effect and the convenience-to-use factor of electricity would increase its share of consumption among all types of energy. As electricity gains dominant status in energy consumption profile, electricity pricing practices will play significant roles in economic development, technology development and energy consumption behaviour.

Globalisation and the demise of the cold war triggered the onset of infinite competition in the world trade. As a consequence, cost reduction became the name of the game in industry restructuring in most countries. Some developed economies in the APEC region initiated regulatory reform in the electricity sector as a part of national efforts to cope with increased competition in the world, while other developing economies started it in an attempt to attract foreign capital for infrastructure development as well as to lower government expenditure.

Electricity industry in the APEC region is undergoing restructuring including regulatory reforms and changes in ownership structure. Privatisation and shifts toward a competitive market from monopoly have become a general trend in most APEC economies. The speed at which the reforms are evolving is different across economies mainly because of differences in national circumstances such as maturity of the industry, the level of technology development, and the extent of infrastructure development. However, competitive electricity markets are becoming more common among APEC economies, with a number of economies currently in the process of introducing competition at all levels of the industry. The United States has largely led the way in terms of competition at both the wholesale and retail levels. Australia, New Zealand and Canada also have wholesale level competition and are in the process of expanding the electricity market across states, and introducing retail competition. A range of economies, including Singapore, Japan, Korea, Thailand, Chinese Taipei, the Philippines, Mexico and Malaysia, are all in the process of establishing competitive electricity markets with market-based pricing mechanisms. The current state of regulatory reform and privatisation processes among the APEC member economies is summarised in Table 6.

TRANSFORMATION IN PRICING PRACTICES

The electricity pricing structure of APEC economies varies according to the overall market structure. Generally speaking, deregulated markets require more complex pricing structures, relative to the simpler cost-of-service pricing approach that has traditionally been utilised in monopoly markets. For instance, whether the retail sector is deregulated and unbundled from the wholesale sector will be a key element in determining end-user prices as prices themselves would be unbundled if the retail sector is unbundled.

In deregulated markets it is relatively common practice for governments, or an independent authority, to regulate transmission and distribution prices, while generation prices are determined in the market. Regulation of transportation functions is typically justified on the basis that they operate as a natural monopoly. Table 8 highlights options for regulating transmission prices, ranging from traditional ROR-based pricing mechanisms to a performance-based approach.

To illustrate, it is often argued that performance-based approach is better than the ROR-based one as the former would offer more incentives for cost reduction. However, the performance-based approach may fail to reflect true cost in prices because of the lack of information on the part of the regulator. This may create equity concerns between electricity suppliers and end-users.

Table 6 Electricity Price Regulation in APEC Economies

Economy	Price regulation	Competitive Wholesale Market
Australia	No	Yes
Brunei Darussalam	Yes	No
Canada	Yes	No
Chile	Yes[a]	Yes
China	Yes	No
Chinese Taipei	Yes	No
Hong Kong (China)	Yes	No
Indonesia	Yes	No
Japan	Yes	No
Korea	Yes	No
Malaysia	Yes	No
Mexico	Yes	No
New Zealand	No	Yes
Papua New Guinea	Yes	No
Peru	Yes[a]	Yes
Philippines	Yes	No
Russia	Yes	No
Singapore	Yes	No
Thailand	Yes	No
USA	Yes	Yes
Viet Nam	Yes	No

Notes: a) Both regulated and unregulated prices.
Source: Adapted and updated from The Benefits and Deficiencies of Energy Sector Liberalisation, Current Liberalisation Status, Volume II, 1998, World Energy Council.

State-based monopoly electricity markets, with regulated or mechanistically administered electricity prices, still remain particularly in developing economies. Price controls are established in Russia, Japan, Korea, the Philippines and Chinese Taipei, although in some cases these are being phased out. Administered prices are prevalent in China, Indonesia and Viet Nam, and are used to assist with wider energy policy objectives.

Transparency is an important issue in pricing practices especially in the case of natural monopoly. As all costs incurred in the fuel chain from generation to distribution could be passed through to end-use consumers, it is important to maintain transparency in price determination process to the extent possible. Otherwise, consumers have to bear unnecessary costs even from mistakes in economic decision-making regarding, for example, investment in facilities and their operation and maintenance.

As shown in Table 8, in case of opaque systems, electricity prices could be subsidised to fulfil, in part, social policy obligations. Electricity consumers can be either directly or indirectly subsidised by governments. In some cases, these subsidies are offered as preferential fuel prices. A report by the Japanese Overseas Economic Cooperation Fund (OECF, 1995) indicates that electricity prices for certain demand categories are set lower than actual costs as a policy measure. In some cases the rates set for the various customer classes were inversely proportional to actual cost structures. For example, rates were set lowest for residential consumers even though the supply cost is highest for them because they have in general (high cost) peaking loads than other type of consumers, say, industrial consumers.

Table 7 shows tariffs by customer class for six APEC economies. The unit supply cost for agricultural and residential customers is actually higher than that for large-scale customers in many cases. The OCEF report shows how revenue shortfalls are made up through higher commercial and industrial rates.

Table 7 Electricity Sector Tariffs in Five APEC Economies

Utility	TNB Malaysia	MEA Thailand	PLN Indonesia	MERALCO Philippines	China (average)
Enterprise	21.3	1.9	125.8	3.1	0.2
Commercial	22.8	2.2	228.6	3.1	N/A
Industrial	14.5	1.5	112.5	2.9	0.12
Unit	Malaysian cent	Baht	Rupiah	Pesos	RMB

Source: Katsuhiko Suetsugu, EAERF, June 1996, Report on East Asian Electricity Restructuring Forum.

For example, Manila Electric Company (MERALCO), the largest distributor of electricity in the Philippines maintains a residential rate of 3.12 pesos per KWh, while its unit supply cost is calculated at 3.9 pesos. On other hand, the rates for commercial and industrial users are set higher than their service costs. This indicates the degree of cross-subsidisation in the provision of electricity in the Philippines.

Table 8 Pricing Approaches under Different Market Structures
Electric Supply Industry

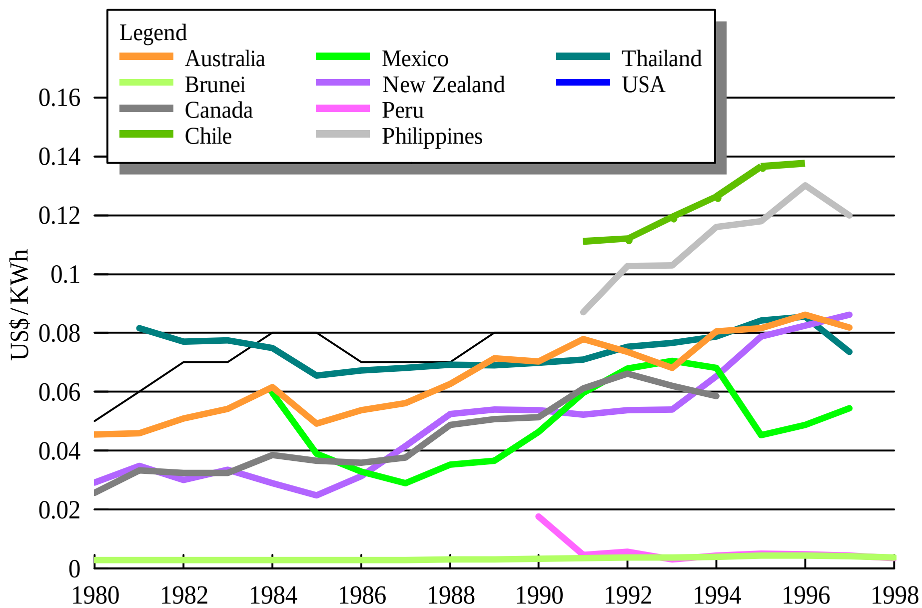
	Monopolistic		Transition	Competitive	
	Administered Prices	***Price Control Regulation***	***Reregulation Process***	***Wholesale Competiti on***	***Retail Competition***
Industry Structure	■ Vertical integration of generation, transmission and distribution ■ Vertical integration of generation and transmission on ly.		■ Unbundling of generation, transmission and distribution segments of the industry. ■ Competition in gene ration.	■ Generation, transmission and distribution are unbundled. ■ Competition in generation ; access to transmission network ; electricity pool.	■ Generation, transmission and distribution are unbundled. ■ Competition in generation ; access to transmission and distribution network ; electricity pool.
Utility Ownership	■ Public sector ownership is dominant.		Increase in private sector participation.	■ Private sector ownership is dominant	
Price Regulation Regimes	■ Generation and retail prices	■ Generation and retail prices are regulated by the government. ■ Rate-of-return (ROR) ■ Price-cap (PC) ■ Revenue-cap (RC) ■ Sliding Scale (SS) ■ Hybrid (H)	Generation, transmission and retail prices are regulated. Adoption of a transparent price regulation regime. In many developing countries undergoing transition or considering transition, price -cap regulatio n appears to be popular.	■ Generation prices are either regulated or not regulated ; transmission prices are regulated ; retail prices are reg ulated ; based on the existing price regulation regime.	■ Generation prices are either regulated or not r egulated ; transmission and distribution prices are regulated ; retail prices are not regulated. ■ Regulation is based on the prevailing price regulation scheme.
Pricing Objectives	■ Seek to balance the following objectives : economic efficiency, finan cial viability and social policy objectives.		In pursuit of economic efficiency and financial viability.	■ Economic efficiency and financial viability	
Price Determination	■ · Price is determined by the government.price determination is either transparent or opaque. ■ In transparent schemes, they are indexed either on LRMC or average costs a nd sometimes adjustments are made to accommodate SRMC changes (TOU or TOD). ■ In opaque systems, prices are sometimes influenced by the social objectives in energy pricing. For instance, prices are subsidized.	■ Rate-of-return – Electricity price corresponds to the operating cost plus the allowed asset rate of return. ■ Price-cap – Costs are based on either average cost or LRMC. Future price is set based on the adjustment factor CPI-X. ■ Revenue cap – Fixed amount of revenue is allowed. ■ Sliding -scale – excessive profit or abnormal loss is shared by regulator and utility. ■ Hybrid – Mixed elements of other regimes.	■ Electricity prices are unbundled. ■ Generation, transmission and retail prices are determined according to the type of price regulation adopted by each country. ■ In the tran sition phase, cross-subsidies are normally removed. ■ TOU or TOD schemes are sometimes introduced.	■ Wholesale prices are market-determined which approaches to SRMC. ■ Peak-period price adjustment is sometimes done to reflect “reliability adjustment”. ■ Other components of electric industry are price regulated – according to the type of price regulation adopted by each country. ■ Stranded costs recovery are also provided.	■ Wholesale and retail prices are market-determined wh ich approaches to SRMC. ■ Peak-period price adjustment is sometimes done to reflect “reliability adjustment”. ■ Other components of electric industry are price regulated – according to the type of price regulation adopted by each economy.
	In developing economies, either prices are administered or regu lated, cross subsidies (either among consuming sectors, geographic regions, or between rural and urban consumers) are prevalent. In several developing countries, a price adjustment mechanism is put in - place to automatically adjust electricity prices due to the fluctuation of input prices.				

TREND IN ELECTRICITY PRICES IN SOME SELECTED ECONOMIES

As shown in Figure 8 and Figure 9, there has been an increasing trend in electricity price over the last two decades. Despite deregulation efforts, electricity prices have not gone down, but gone up instead even in cases of the United States and Australia, that are well advanced in terms of deregulation of the electricity sector compared to other economies in the region. There are many factors to be considered in order to determine whether deregulation in fact improved efficiency of the electricity industry, resulting in the reduction of end-use prices. It would be difficult, however, to single out the impact of the change in one factor on electricity price.

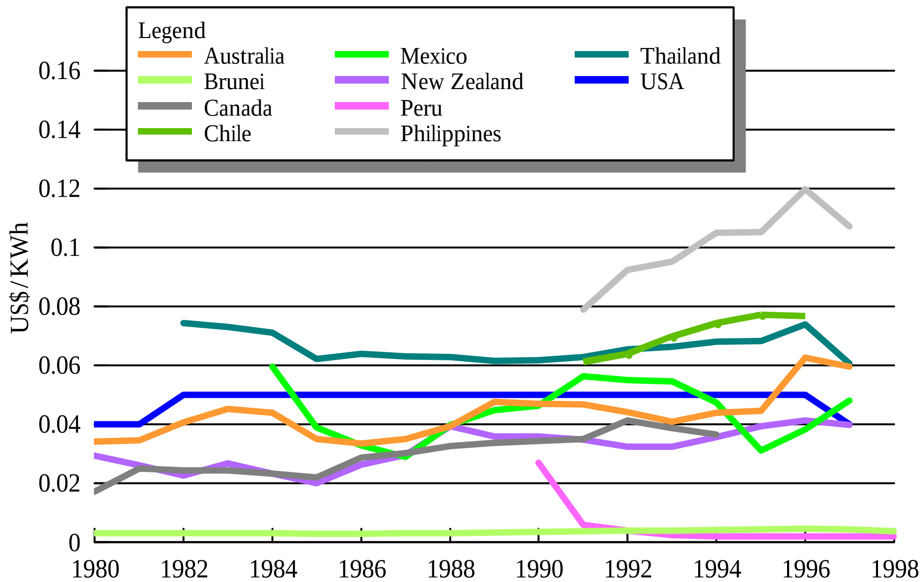
The evidence as shown in Figure 8 and Figure 9 seems to be counter-intuitive. As pointed out by Walker and Lough (1997), deregulation might not provide a guarantee for lower electricity prices. They further argued that rates could fall after deregulation only in countries where low cost, exploitable resources were available or alternatively economic opportunities in privatisation were present at the time of deregulation.

Figure 8 Residential Electricity Prices in Selected APEC Member Economies
US$/KWh



Source: IEA and APEC Energy Database.

Figure 9 Industrial Electricity Prices in Selected APEC Member Economies
US$/KWh



Source: IEA and APEC Energy Database.

CHAPTER 4

EXISTING APEC ECONOMY ENERGY PRICING PRACTICES

OVERVIEW

This chapter briefly discusses the existing energy pricing practices in most APEC economies. The chapter is intended to provide a quick reference to the energy pricing objectives and policies of APEC economies, as well as recent developments in the energy sector with implications for energy pricing. General energy policies for coal, petroleum products, natural gas and electricity are reviewed, and can be used as a general background to the pricing practices pursued in each economy.

CHAPTER CONTENTS

AUSTRALIA

Australian energy policies over the last decade have been designed to improve efficiency in the energy sector, primarily through improving competition, transparency and integrating regional markets. These reforms have tended to lower energy prices in Australia, though it is arguable whether all consumers are advantaged. The reforms have been focused on improving efficiency, and, therefore, environmental initiatives have not been a major component of the reforms.

COAL

Australian coal is the second largest producer in the world and its coal production has increased at average 5.5 per cent per annum over the past 5 years. As shown in Table 9 that coal production is predominantly consumed for export commodity with 70 per cent of the total coal production. Domestically coal is used primarily for electricity generation, which accounts for around 90 per cent of domestic coal supply. The coal requirements for power stations are accessed primarily through competitive open tenders, except in Victoria where (brown) coal is tied directed to the power generators. In the industrial sector, coal is generally sold on a long-term contractual basis (IEA, 1997). The industry sector is the other main consumer, with the iron and steel sector dominating industrial consumption.

With the emergence of the National Electricity Market, which began operation in May 1997, competition in the electricity market has exerted downward pressure on domestic coal, which is expected to continue. Competition from alternative fuels such as gas has also acted to limit coal prices.

Table 9 Past Trend of Coal Production and Supply in Australia
ktoe

Year	**Production**	**Domestic**					**Export**	
		Electricity	Share to domestic	Other	Share to domestic	Total	Export	Share to production
1994	119226	31826	89 %	3890	11(%)	35716	90078	75(%)
1995	128594	29916	76 %	8996	24(%)	38912	89682	70(%)
1996	131636	35922	88 %	4853	12(%)	40775	90862	69(%)
1997	139917	35772	76 %	11252	24(%)	47024	95973	69(%)
1998	147836	38517	88 %	5194	12(%)	43711	105172	71(%)

Source: APEC Energy Statistics 1999.

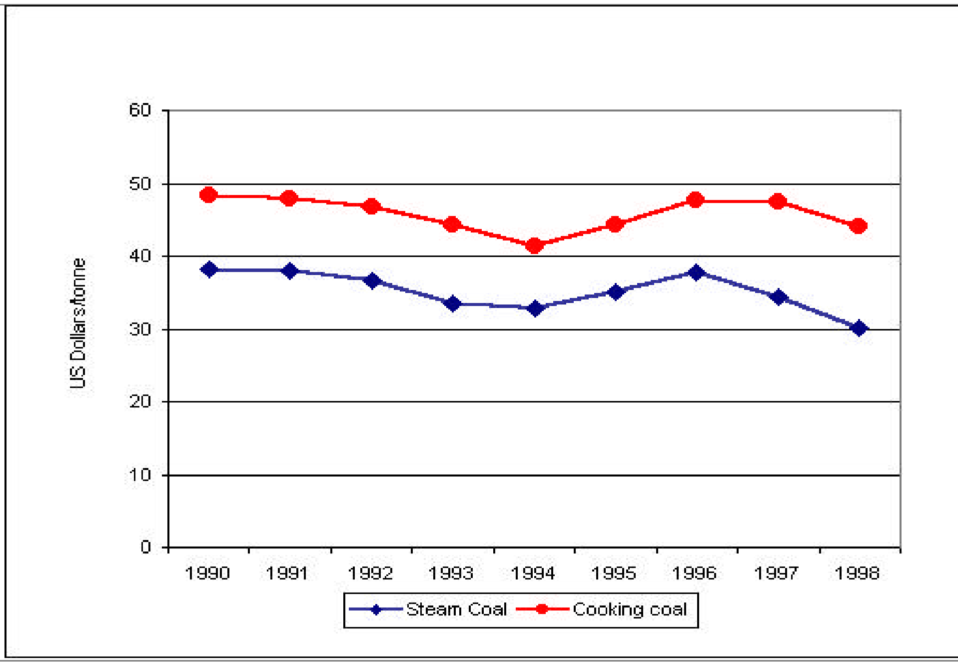
Coal is Australia’s single largest export commodity accounting for around 10 per cent of Australia’s merchandise trade. The majority of Australian coal exports are directed towards Japan, which consumes around 90 per cent of coking coal and around 75 per cent of steaming coal exports. Long–term contract coal prices have traditionally been negotiated with representatives of Japan’s steel mills and electric utilities, with revisions taking place on an annual basis. Negotiated coal prices would provide a benchmark for exports to other economies, such as Korea and Chinese Taipei. More recently, coal exports have been sold on the spot market or via tenders, generally at lower prices. The downward pressure on coal prices reflects a number of different factors, including:

- Continued emergence of low cost suppliers from Indonesia and China;

- Increased domestic competition in Japan's electricity market, and the acceptance of marginally lower supply security associated with purchases on the spot market and through tenders;

- Technological developments that have reduced the requirement of high quality coking coal necessary in the production of steel, hence lower the premium demanded by Australian exporters.

Figure 10 Past Trend of Coal Export Prices in Australia
US$/tonne



Source: IEA Statistics, Second Quarter 1999

Figure 10 shows the coal export prices for cooking coal and steam coal. It shown that the steam coal price has decreased sharply since mid-1996 to 30 US dollars/tonne from 37.7 US dollars/tonne. However, the coking coal decreased slightly to 43.9 US dollars/tonne from 47.6 US dollars/tonne.

PETROLEUM PRODUCT

Australian petroleum production has remained relatively static since 1986, as no further oil fields have been discovered. Since 1986, Australia has changed from a net oil exporter to a net oil importer, and in 1997 imported oil accounted for about 10 per cent of domestic consumption.

Table 10 Petroleum Energy Consumption in Australia
ktoe

Year	Agriculture		Residential & Commercial		Industry		Transport		Total
	ktoe	%	ktoe	%	ktoe	%	ktoe	%	ktoe
1990	1113	3.7	632	2.1	5331	17.7	21921	72.6	30193
1991	1120	3.8	630	2.1	5246	17.6	21708	72.8	29825
1992	1114	3.7	659	2.2	5202	17.2	22130	73.3	30198
1993	1174	3.7	566	1.8	5670	18.0	22839	72.7	31431
1994	1214	3.7	676	2.1	6191	18.9	23444	71.5	32801
1995	1247	3.7	657	1.9	6001	17.8	24465	72.6	33706
1996	1250	3.6	651	1.9	5901	17.0	25488	73.6	34632
1997	1300	3.7	658	1.9	5966	16.9	25954	73.5	35334
1998	1336	3.8	652	1.9	5556	15.8	26235	74.6	35150

Source: APEC Energy Statistics, 1997.

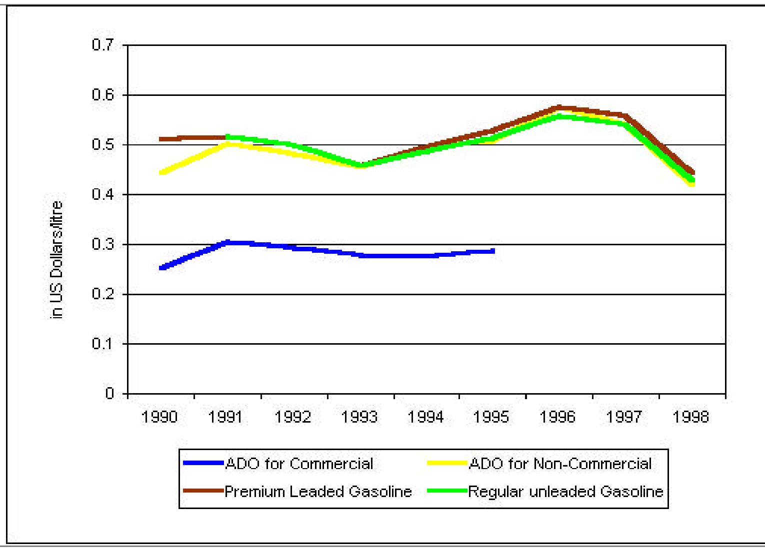
During the past eight years, the petroleum consumption has increased at average 2.2 per cent per year. Over 70 per cent of petroleum product was mainly used for transportation and industrial consumption was around 17 per cent as shown in Table 10. The share of particular sector did not change where agricultural and residential shares were less than 5 per cent.

The Australian Competition and Consumer Commission (ACCC) sets a maximum wholesale price for gasoline and automotive diesel, based on Singapore prices converted to Australian dollars plus a 'local' component reflecting storage, distribution and other costs. Government taxes are added to set the maximum consumer price (IEA, 1997). Prices above the maximum set by the ACCC have to be justified by the particular oil company.

The retail petroleum market is, arguably, not adequately competitive and the four major oil companies are able to exert effective control on retailers through exclusive supply agreements, price supports and oil company cards. Thus while the number of retail outlets that individual companies can own is limited, the number of outlets dominated is higher (IEA, 1997).

Figure 11 shows the past trend of petroleum product prices during the last eight years including tax price. The price decreased sharply between 1996 and 1998 for all petroleum products. From the 7 August 1997, the State Government Business Franchise Fees have been abolished and are now part of the Commonwealth Excise Tax (IEA Statistics).

Figure 11 Past Trend of Petroleum Product Prices in Australia
US$/litre



Source: IEA Statistics, Second Quarter 1999.

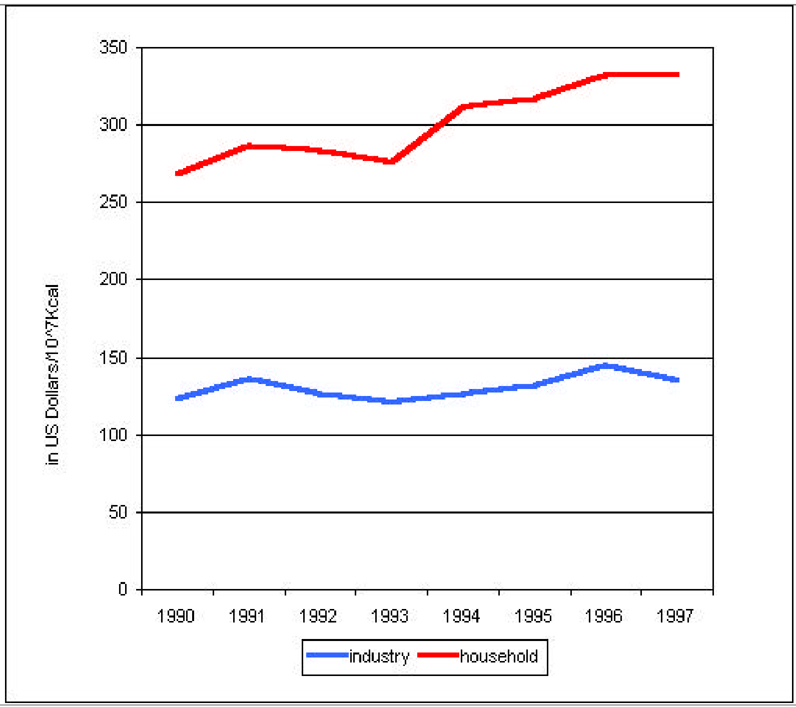
NATURAL GAS

Australia is in the process of introducing a number of market reforms in the natural gas market, generally aimed at opening access to natural gas supplies, eliminating cross-subsidies, integrating regional markets and increasing competition, especially in the retail market. Domestic natural gas prices vary between states reflecting the level of regional development. Cross-subsidies also exist in the tariffs charged to end-use consumers with households typically paying prices below total supply cost and industry paying higher prices.

With the emergence of the National Electricity Market (NEM), and particularly the initial fall in pool prices, some gas-fired generators were "mothballed" as they were financially uncompetitive relative to the cheaper coal generators. Currently, with the higher pool price, it is not known whether the gas generators will be reintroduced.

Figure 12 shows that the natural gas prices for household and industry. During the past eight years the price for household has increased sharply to 332 US dollars/toe in 1997 from 269 US dollars/toe in 1990. Nevertheless, the price for industry slightly rose to around 136 US dollars/toe by 1997 from 123 US dollars/toe in 1990.

Figure 12 Natural Gas Price for Industry and Household in Australia
US$/toe



Source: IEA Statistics, Second Quarter 1999

ELECTRICITY

Coal is the major player for electricity sector where over 80% of electric power has been generated from coal as shown in Table 11 and followed by natural gas, hydro and petroleum product with their shares being about 9 per cent, 4 per cent and 3 per cent, respectively, in 1990.

Table 11 Electricity Production by Fuel Type in Australia
ktoe

	Coal	Petroleum	Natural Gas	Hydro	Total
1990	28898	919	3072	1280	34169
1991	29931	900	2610	1385	34826
1992	30771	666	2406	1315	35158
1993	30909	622	2931	1457	35919
1994	36406	644	3181	1445	41676
1995	29956	728	3596	1395	35675
1996	35957	725	3297	1379	41358
1997	35815	560	3256	1478	41109
1998	38551	525	3434	1395	43905

Source: APEC Energy Statistics 1977

The portion of coal rose to 88 per cent in 1998 from 84 per cent in 1990. But, petroleum product share reduced from 3 per cent in 1990 to only 1 per cent in 1998. The Australian government policy recognises that coal will continue to play an important role in Australia's energy mix well into the future. Efforts have been put into improving the efficiency of the power sector and facilitating greenhouse gas research.

Electricity consumption has increased by 3 per cent during the past eight years in line with household growth rate around 3.3 per cent as shown in Table 12. During the same period, industry sector and other sector growth rate is about 2.7 per cent. Household is the largest consumer, which accounts for 50 per cent of total electricity consumption and followed by industry sector around 47 per cent. Others, electricity are used for agriculture and transportation.

Table 12 Electricity Consumption in Australia
ktoe

Year	Household	Industry	Others	Total
1990	5661	5430	350	11441
1991	5837	5453	372	11662
1992	5896	5554	381	11831
1993	6056	5716	389	12161
1994	6191	5865	405	12461
1995	6462	5999	395	12856
1996	6755	6053	404	13212
1997	7029	6217	413	13659
1998	7357	6720	431	14508
Average growth rate (%)	3.34	2.72	2.66	3.02

Source: APEC Energy Statistics 1977

Responding to signals throughout the 1980's that micro economic reforms were needed throughout the Australian economy, the Federal government asked the Industry Commission to investigate the generation, transmission and distribution of electricity in Australia, and particularly to examine the scope for efficiency improvements. The report recommended vertical segregation of generation and retail from the natural monopoly elements of transmission and distribution, as well as the corporatisation of utilities, additional interconnections and the introduction of competition in the retailing and generation markets.

Following the introduction of various government reforms, the first stage of the National Electricity Market began operation in May 1997, which became fully operational around December 1998. The NEM is an integrated competitive wholesale market for the trading of electricity that operates in New South Wales, Victoria, the Australian Capital Territory and South Australia. Although not yet interconnected, the NEM reforms were also introduced concurrently into Queensland.

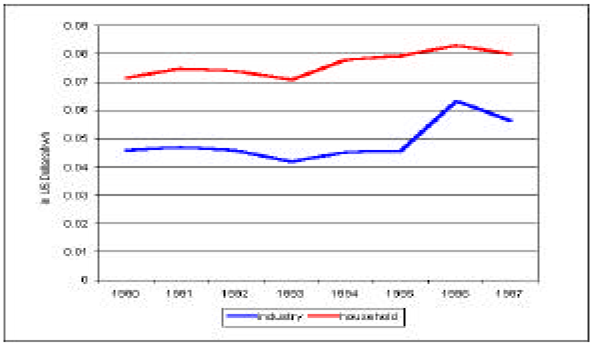
The wholesale electricity pool price is calculated each half hour based on the weighted average of six five-minute dispatch prices making up the half hour. Pool prices for electricity just prior to the introduction of the National Electricity Market in May 1997, were in the range of AUD$18/MWh. This fell in the following months to around AUD$12-14/MWh as generators competed for market share. These lower prices proved to be unsustainable and with the mothballing of some plants, pool prices rose to around AUD$23/MWh by December 1998, and have further increased to AUD$30/MWh currently.

While most market analysts agree that current prices are still below the long-run marginal cost (LRMC), it needs to be recognised that spot market prices may not accurately reflect the final return to generators since over 80 per cent of supply is affected by commercial and vesting contracts that are not necessarily reflected in the pool price.

Competitive contracts can still be negotiated under the NEM arrangements between individual generators and retailers for the part of the market that is contestable. The contracts market is quite separate from the wholesale spot market, but generators must still bid to be dispatched to meet any call on these contacts.

As deregulation initiatives have gradually been introduced, generators have been required to increase efficiency and reduce costs. Productivity increases, measured by the Australian Productivity Commission, have averaged 10.75 per cent per year over the period 1993-4 to 1997-8. In line with these productivity improvements, the Productivity Commission has also confirmed that energy market reforms have realised average reductions in real prices of electricity of around 24 per cent for all-end users since 1991-92.

Figure 13 Past Trend of Electricity Price for End-Users in Australia
US$/kWh



Source: IEA Statistics, Second Quarter 1999

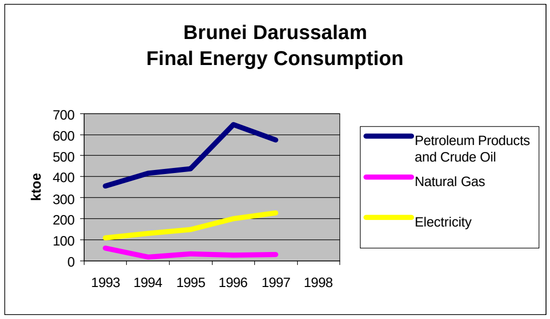
Electricity prises to end-users, especially for household and industry, are shown in Figure 13 in US Dollars/kWh during the past eight years. Household electricity prices are higher than industry user. The prices respectively were 7.1 cent US Dollars/kWh and 4.6 cent US Dollars/kWh in 1990. Both household and industry electricity price rose slightly over the eight years where 8 cent US Dollars/kWh for household end-users and 5.6 cent US Dollars/kWh for industry end-users in 1997.

BRUNEI DARUSSALAM

While the pricing system has recently been adopted market-based method, social objectives remain the dominant factor in energy pricing policy. In the past, concession-type contracts existed with respect to natural gas development and production. Currently, Brunei Darussalam has adopted a competitive bidding arrangement in oil and gas exploration, and some petroleum products are already priced according to market mechanism.

Final energy consumption in Brunei Darussalam during the last five years is shown in Figure 14.

Figure 14 Brunei Darussalam Final Energy Consumption
1993-1998



Source: APEC Energy Database

PETROLEUM PRODUCTS

Brunei Darussalam has the largest energy consumption per capita in Southeast Asia. Crude oil and petroleum products supply slightly decreased to 180ktoe in 1994 and increased to 466ktoe in 1997, while the consumption increased from 416ktoe to 576ktoe during the same period.

ELECTRICITY

Electricity consumption increased steadily from 109ktoe in 1993 to 228ktoe in 1997, although there seems no significant correlation to the electricity tariff, which remains constant at one Brunei cent for residential and industrial customers during the same period.

CANADA

Canada is richly endowed with energy resources and is a net exporter of all the main energy commodities: electricity, oil, natural gas, and coal. Oil accounts for about 35 per cent of primary energy supply, gas for 28 per cent, coal and others for 11 to 12 per cent.

COAL

Canada has very large proven recoverable reserves of coal, 6.5 billion tonnes, or about 100 years worth of supply at current production level. In the early decades coal was the dominant source of primary energy in Canada, and a gradual upturn in coal use reoccurred in 1970s, after the oil shocks. The structure of the coal industry is the result of its diverse geographic distribution, its history of development and public policy. Canada has 28 producing mines of which the majority is located in the western provinces, which accounted for 96 per cent of total production and owned by private companies. (IEA, Energy Policies of Canada 1996 Review)

Domestic consumption is in the power generation, coal-fired electricity production accounting for about 16 per cent of total production. The government forecasted an increase in coal consumption for power production over the period to 2010. Canada exports its coal to the single largest market, Japan and South Korea. Prior to the Asian financial crisis, the coal production increased by average 3 per cent per annum and export were up by 5.5 per cent preserving Canada as the world's fourth largest exporter.

Table 13 Canada's Coal Demand and Supply
Million Short Tonnes

Year	1989	1990	1991	1992	1993	1994	1995	1996	1997	1998
Consumption	59.99	54.95	56.01	47.94	54.19	58.12	58.53	59.13	62.03	65.69
Production	77.73	75.35	78.41	72.32	76.09	80.28	82.57	83.47	86.70	83.09

There are no government interventions in price setting and no import/export quotas, tariffs practices applicable to Canadian coal trade. The provincial government set royalties and taxes on coal production and no federal taxes on production. With regard to consumption, coal is subject to the federal Goods and Services Tax (GST), currently at 7 per cent refundable on business inputs.

The Cape Breton Development Corporation (CBDC), the Federal Crown Corporation, received subsidies from both federal and provincial governments. However, in April 1995, federal subsidies were removed and the CBDC was looking at privatisation to improve productivity in the coal mine. The Canadian railways, the major coal carrier, is also soon to be privatised. This would impact the coal price since transportation cost accounts for about 50 per cent of total FOB cost, the more competitive railway company and lower transportation rates could lower the coal FOB cost as well.

PETROLEUM PRODUCT

The private sector owns production and distribution activities in the oil industry. Three major oil companies, Esso, Petro-Canada, and Shell, account for 60 per cent of all refining and retailing outlets. Since the deregulation in the mid-1980s, production levels and pricing have depended entirely on domestic and international market forces. Oil demand reached a low point in 1983 following the oil price increase in 1980 and the subsequent recession in during 1980 to 1982. Oil demand except fuel oil is expected to increase slightly by an average of 0.7 per cent per year to the year 2000 and 1 per cent to the year 2010. Fuel oil demand decrease reflects fuel substitution to natural gas in power generation.

The Canadian oil sector was heavily regulated between 1973 and 1985. Domestic crude oil prices were held below world levels, while imports and exports were subject to tax and levy, rebates and export charges. The Canadian government deregulated oil prices in 1985. As a result, the prices are in line with market forces.

Only Prince Edward Island has petroleum product price regulations in place, with wholesale prices and retail markings set by the Public Utilities Commission. The GST currently applies 7 per cent to all products and is refundable for business purchases. Both the federal and provincial governments levy taxes on gasoline, jet fuels, and diesel fuel as shown in the Table 14.

Since deregulation and rationalisation involving mergers and acquisitions, downsizing has occurred in the oil industry to improve performance and to increase competitiveness of the oil industry to the world oil market.

Table 14 Levied Taxes on Petroleum Products in Canada
1996

Federal Excise taxes on gasoline	
Gasoline Unleaded	10 cents/litre
Aviation Fuel	11 cents/litre
Diesel Fuel	4.0 cents/litre
Provincial gasoline and Diesel average sales taxes	
Gasoline Regular	Not in use in Canada
Gasoline Unleaded	14.8 cents/litre
Diesel	13.9 cents/ litre
Premium Unleaded Gasoline	15.7 cents/litre
Subsidies	None

Source: Natural Resources Canada, January 1996

NATURAL GAS

Around a half of Canada's gas production is currently exported to the United States, and consequently the United States demand levels strongly influence Canadian gas prices. Traditionally Canadian traded wellhead gas prices were substantially lower than the NYMEX, primarily due to the higher transportation costs to demand areas. However, with the completion of major trans-border pipelines into the United States, the Canadian/NYMEX differential has closed considerably during the 1990s.

Increases in Canadian gas production and the utilisation of spare capacity, combined with gas-on-gas competition, have resulted in a decline in Canadian gas prices. This trend is also consistent across North America where gas prices have decline by almost 50 per cent over the last ten years. Canadian projections to 2010 suggest a modest recovery in gas prices to around $2.05/Mcf (1995 US dollars) by 2010, from the present $1.65. Wellhead prices in Canada.

Natural gas production is subject to provincial royalties which may vary depending on the date of discovery, gas prices, well productivity, and various specific arrangements. Provincial revenues associated with natural gas output consist mainly of Crown royalties, freehold taxes, and corporate income taxes. The Federal Government and two producing provinces, Saskatchemwan and British Columbia, also apply a corporate capital income tax.

The Canadian government deregulated gas prices in 1986 under the Federal-Provincial Agreement on Natural Gas Markets and Prices of 1985. The governments agreed to withdraw from price regulation while ensuring enhanced access for Canadian buyers to natural gas supplies and for producers to natural gas markets. Domestic and export prices are determined through direct negotiations between buyers and sellers.

ELECTRICITY

The provincially owned electric utilities owned about 83 per cent of Canada's total installed generating capacity and produced about 78 per cent of total generated electricity. Investor-owned utilities accounted for 9 per cent of all capacity and produced about 12 per cent of total electricity. In addition to electric utilities, there are about 60 industrial establishments (self-producers) generating electricity mainly for their own use. These industrial establishments owned about 6 per cent of total capacity, including pulp and paper, mining, and aluminium smelting sectors. Electricity consumption rose only 1.3 per cent in 1994. The demand projections are developed and the outlook is an increase of 1.3 per cent per year to 2020; major electric utilities forecast 1.4 per cent growth. Most of generation is from hydroelectric resources. The generation grew by 5 per cent in 1994. The increase in domestic demand and in exports to the United States contributed to the increase in generation. The exports to the United States grew 53 per cent in 1993.

The Canadian federal and provincial governments maintain some controls over electricity pricing. In particular, the federal government regulates electricity exports to the United States, and acts to prevent anti-competitive practices among private electricity companies. Provincial governments are responsible for the setting of electricity generation, transmission and distribution prices, and intra-provincial power markets. In addition, the North American Electricity Reliability Council (NERC) is responsible for matters related to power system reliability.

In Canada the majority of electric utilities develop their pricing structure from cost-based approaches, including the cost-of-service approach for commercially operated (largely privately investor-owned) utilities. The pricing structure is subject to approval by the provincial government, or appropriate provincial regulatory body. Discrepancies exist between provinces reflecting differences in the source of power generation, transmission and distribution costs, time of year and size of the consumer. Table 15 represents prices paid by Canadian utilities for IPP power, and is indicative of the variation in electricity prices across Canada.

Table 15 Prices Paid by Canadian Utilities for IPP Power
Canadian cents/kWh, 1995

Utility	Average (c/kWh)	Peak (c/kWh)	Off-Peak (c/kWh)	Comments
Nova Scotia Power	3.00			Avoided cost
NB Power		5.5	3.8	Less than 5MW
	3.34			Greater than 5MW
Hydro-Quebec	4.9			Greater than 15MW
	5.3			Less than 15MW
	4.0			Renewables (summer)
	7.3			Renewables (winter)
Ontario Hydro		6.2	1.8	Summer
		6.9	2.8	Winter
Manitoba-Hydro	4.0			Greater than 2MW
	4.9			Less than 2MW
				Residential
Alberta Power	3.4			Hydroelectricity only

Source: Canadian submission to the APEC Energy Regulators' Forum, 1997

The cost-of-service approach requires that prices be determined on a periodic basis, incorporating estimates of the electricity generated and costs of generation, plus a return on investment. Since prices are set to provide sufficient net revenue, there is little incentive for utilities to be efficient and further, since the return is based on assets, there may be an incentive to over-invest. To avoid these potentially negative effects, some provinces have considered or already implemented regulations to create a more efficient pricing mechanism.

CHILE

Chile has embraced the concept of the market-driven economy, and geared policies towards free trade and privatisation of state-owned energy companies. The central aim of Chilean energy policy is to satisfy the main requirements of energy, while protecting consumer's rights and the environment. The recent introduction of natural gas from Argentina has worked to diversify energy sources, help satisfy growing energy demand, and provide energy at competitive prices. A significant portion of Chilean energy demand is from the mining sector, which is the major power consumer and also Chile's biggest industry. This has been complemented by growth in large urban areas in central Chile, particularly in the vicinity of Santiago.

COAL

The Chilean coal industry was traditionally heavily subsidised by the government, reflecting the high cost of mining. With the removal of coal subsidises in the early 1990's, domestic coal production was non-competitive relative to coal imports and alternative energy sources, particularly gas, causing widespread mine closures. By 1996, Chilean coal production was less than 50 per cent of the 1991 level, despite an increase in consumption of almost 100 per cent between 1991 and 1996, facilitated by increased coal imports. Coal imports into Chile, predominantly from Colombia, are not subject to government controls. Coal imports are purchased directly from exporting economies, and also through the spot market.

PETROLEUM PRODUCTS

Chile is dependent on oil imports for the bulk of the domestic supply. Chile mainly imports crude oil from Argentina, Nigeria and some South American countries through the state-owned oil company, Empresa Nacional del Petroleo (ENAP), to Chile's refineries. However, recently imports of refined oil products, particularly diesel, have increased considerably.

Chilean oil prices from domestic refineries to wholesalers and distributors are determined according to an international parity scheme that compares international prices to domestic ones. To dampen the effect of international oil price fluctuations in the Chilean market, an oil stabilisation fund (FEP) was created in 1991. The operating mechanism considers a price band for petroleum products, and applies a subsidy or tax to prices outside the band. If in a given week the average import price (import parity) exceeds the upper limit of the band, a subsidy is applied to consumers during that week, for the difference between the import price and the upper limit. Likewise, when the average import price falls below the lower limit, a tax is applied to consumers, for 60 per cent of the difference between import price and the lower limit of the band. In the long run, subsidies and taxes offset each other, making this mechanism neutral. The market sets petroleum product prices to end-users, although clearly this price will account for, and respond to, the international parity system.

NATURAL GAS

Chilean gas demand, especially for power generation, is projected to grow rapidly over the next decade, and is expected to partially replace coal and heavy fuel oil in the energy mix. Gas supply is projected to rise rapidly as further pipelines are constructed from Argentina.

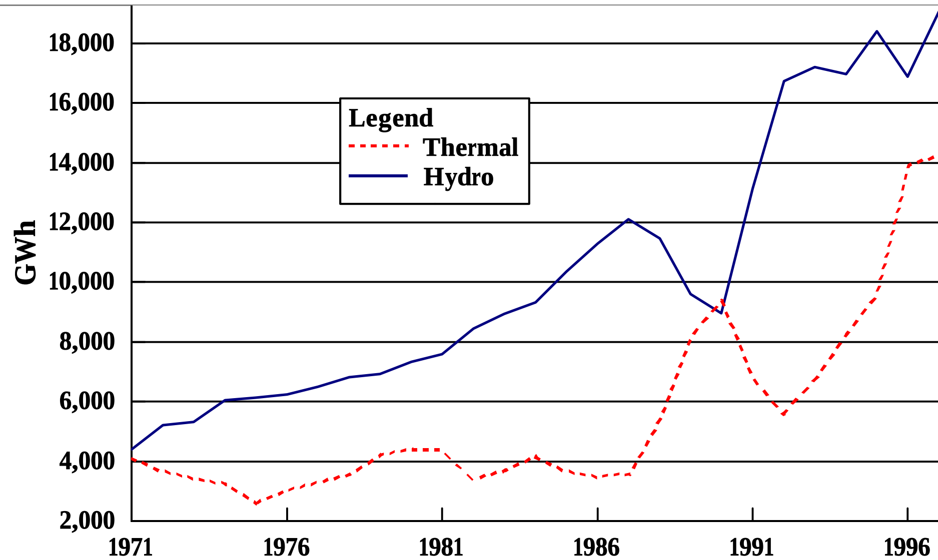
In the northern Chilean market, gas pipelines from Argentina currently supply power plants in the region. Strong competition between them and with a new power interconnection, also from Argentina, together with the non-existence of connections of either pipelines or electricity grids to the central market, have resulted in an oversupply of electricity in the northern market which has reduced electricity prices by around 25 per cent.

While industrial gas demand is increasing – in part due to environmental reasons – the primary demand for gas will continue to be the power sector. Currently the residential sector is not a major consumer of natural gas. However, residential private retail supply companies are increasingly targeting gas markets, particularly in newer housing developments

ELECTRICITY

Chile's electricity demand is closely linked to GDP. In the last 20 years (1977 to 1997), electricity demand has grown at an average annual rate of 7.4 per cent. Under normal hydrological conditions, this demand is supplied mainly with hydropower and to a lesser extent with thermal generation (see Figure below).

Figure 15 Chile's Electricity Supply
1971-1996



Source: APEC Energy Database

However, the share of thermal generation is expected to increase significantly with the construction of combined cycle plants, as a result of the introduction in 1997 of natural gas from Argentina. In fact, prior to this date, generation from this source was almost negligible. According to the 1999 indicative planning of the Chilean National Energy Commission, of the total 4,831 MW that are planned to be installed until the year 2008, 83.2 per cent will be of natural-gas-fired power plants and 16.7 per cent of hydro stations. Thus, it has been estimated that natural gas could account for nearly 43 per cent of the total generation by the year 2020. The following table shows the installed capacity in 1999 by energy source.

Table 16 Installed Capacity by Energy Source in Chile
1999

	Hydro	Natural Gas	Coal	Oil	Other	Total
MW	3,876.1	1,294.1	931.7	562.4	187.3	6,851.6
Share (%)	56.6	18.9	13.6	8.2	2.7	100.0

Source: National Energy Commission of Chile (CNE)

Chile was one of the first economies in the APEC region to fully privatise and unbundle the national generation, transmission and distribution. Currently there is competition between generators, but transmission and distribution remains regulated reflecting its natural monopoly attributes.

Electricity prices in Chile aim to approximate the free market. Generators may sell power and energy to other generators, to distribution companies, and to large customers, known as 'free clients', who consume in excess of 2 MW. Electricity is sold either as short- or long-term contracts, or alternatively through the spot market. Contractual sales to other generating companies or free clients are not regulated, but those in the spot market are. Transactions on the spot market among generators are valued at the system marginal cost of the interconnected system in which the companies are located. The Economic Load Dispatch Centre (CDEC) sets system marginal cost in each system taking account of the main variables affecting the cost of capacity and energy supply. For capacity, the system marginal cost is set twice a year based on the cost of a new diesel gas turbine generation facility. The determination of the system marginal cost for spot market electricity is based on: demand forecasts, reservoir levels, fuel costs for thermoelectric generating facilities, maintenance schedules and others.

Transmission tolls are fixed according to a formula that reimburses the owner of the transmission lines for a portion of its investment and operating cost for the transmission lines used. Prices for regulated consumers, who have no negotiation capacity and are supplied by distribution companies resembling natural monopolies, are determined in two stages:

Firstly, between generators and distribution companies, the node prices apply. Node prices are calculated every six months based on the projected short-term marginal cost of satisfying the demand. Marginal costs in the Central Interconnected System (SIC) are calculated over the next 4 years, and in the Interconnected System of the Great North (SING) over the next two years.

A tariff formula is used which takes into account projections of the main variables in the cost of energy at each substation in the system over the relevant time period. The variables include:

- projections of demand growth;
- reservoir levels, which determine the availability and price of hydroelectricity;
- fuel costs for thermoelectric facilities;
- variations in exchange rates of foreign currencies relevant to raw materials;
- planned maintenance schedules or other factors that would affect the availability of existing generating capacity; and,
- scheduled new additions to generating capacity during the relevant period.

These marginal cost projections assume efficiency in operations and future investment. Indexations allow adjustments during the six-month period if changes in the underlying assumptions used to project the node prices in effect would result in a change of more than 10 per cent in the node price calculation.

The regulation requires that the difference between node prices and the actual prices charged to non-regulated customers in the prior six-month period should not, on average, exceed 10 per cent. If this requirement is not met, the National Energy Commission must make the necessary adjustments.

Secondly, final prices between distribution companies and end-users reflect the applicable node price plus an additional charge for the electricity distribution service, which is known as the distribution value added. The tariffs to end-users are based on the expansion and operation costs of model companies operating efficiently in typical electrical distribution zones, so the eventual inefficiencies that could exist in investments and operation of real distribution companies cannot be passed on to consumers; rather, companies have incentives to increase their efficiency. The regulation states that the tariffs should allow the distribution companies of the respective typical distribution zone to have a nominal rate of return in the range of 6 to 14 per cent. Distribution tariffs are calculated every four years, with monthly indexation to allow adjustments due to variations in node prices and other factors affecting distribution costs.

The high percentage of hydroelectricity in Chile can lead to high electricity price variability in Chile's electricity supply, induced as a result of changing hydrological conditions, which influence reservoir levels. Node prices have fallen steadily over the past few years to around US$19.7 per MWh (based on the April 1999 Alto Jahuel base node price and an observed exchange rate of 540.39 CH$/US$). The decrease can be mostly attributed to the arrival of Argentine natural gas and the start-up of combined-cycle generating plants.

CHINA

Energy pricing reform in China began in the 1980's, which was called "dual-track pricing system". A portion of energy products could be sold in higher price than the centrally planned. Now, the price liberalisation has improved in every energy sector while coal price is completely market-based. Even though there are still some price-control regulation and subsidies in oil, natural gas and electricity sectors, evidences indicate that energy pricing will be further developed.

COAL

China is the largest coal producer in the world, of which the annual production in 1996 was around 1.4 billion tons with 4.6 per cent average growth rate over the period between 1986 and 1996. Generally, coal producers can be divided into two groups: stated-owned coal companies and local coal companies. As Table 17 shows, coal produced by local coal companies accounted for 62 per cent of total coal outputs and its growth rate was more than double the stated-owned ones'.

Table 17 Coal Production by Ownership in China
Million Tons

	Total Production	Stated-owned Coal Company		Local Coal Company	
		Production	Share	Production	Share
1986	894.04	413.92	46%	480.12	54%
1988	979.87	434.45	44%	545.42	56%
1990	1079.88	480.22	44%	599.66	56%
1992	1114.35	482.54	43%	632.01	57%
1994	1229.53	468.67	38%	760.86	62%
1996	1397.00	537.25	38%	859.75	62%
Average Growth Rate	4.6%	2.6%		6%	

Source: 97 Energy Report of China

Table 18 shows the sectoral coal consumption shares. Electricity generation and industry sectors dominated coal consumption with more than 70 per cent share. However coal consumption in residential and transport sector declined significantly. As the economy develops, coal demand still keeps growing, while its share in primary energy consumption is going to drops.

Table 18 Coal Consumption by Sector in China
Per cent

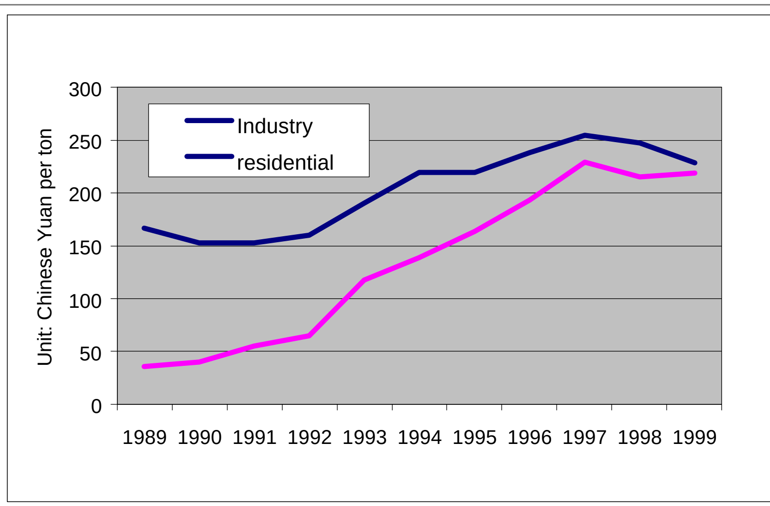
	Electricity Generation	Residential	Transport	Industry and Others
1985	22.09	22.82	3.49	51.6
1987	23.54	23.1	2.9	50.46
1989	25.31	19.56	2.27	52.86
1991	28.54	17.7	2.05	51.71
1993	32.28	12.96	1.64	53.12
1995	32.28	9.83	0.96	56.93

Source: 97 Energy Report of China

Traditionally, the coal industry has been a subsidised sector in China and the price was kept at low levels until 1980s. With the implementation of "Dual-Track Price" policy in 1980s, unplanned coal price increased from 80 Yuan/ton in 1987 to 136Yuan/ton in 1991 while planned price from 36 Yuan/ton to 61 Yuan/ton at the same year. During the complete nation-wide price liberalisation from 1993 to 1995, coal price increased sharply. However, the price dropped again from 1997 due to supply surplus.

Coal consumption in the residential sector could get more subsidies from local government which made the price even lower. With low dependence on coal in the residential sector, the subsidies were removed that led to similar prices in these two sectors. With the high stock (about 200 million tons) and insufficient demand, coal price will stay at al low level for a long while.

Figure 16 Coal Price Trend in China



Source: China Energy Prices Database 1989 - 1999, China Price Information Center

There were three major stages for coal pricing in China.

- From 1958 to 1978: During this period, coal price was completely controlled by government. Consequently, government intervention was unique measure in pricing at that time.

- From 1983 to 1990: "Dual-Track Price system" was launched that permitted higher price for the excess over planned coal outputs in order to promote coal production and reduce rapid increasing subsidy expenditure. The policy covered all coal producers of different ownership. The unplanned price referenced the planned price and could cover cost. Government still played a crucial role in price making. With high share of local coal outputs in the late 1980s, market was beginning to influence coal price strongly.

- From 1993 to 1995: Complete price liberalisation was initially carried out in eastern area and then spread to the west. Market replaced government to dominate the case. With relatively sufficient coal supply, price did not rise much. At the same time, government reduced subsidies for coal industry.

The coal price liberalisation has led to major achievements. One is the coal companies started to improve management and to try hard to reduce cost so as to get market position. The other is that the high price enforces coal consumers to improve energy efficiency.

PETROLEUM PRODUCTS

Domestic crude oil production was 157.29 million tons in 1996 when petroleum refineries shared 95 per cent of total output. From 1993, China became a net oil importer, with net oil import being 18.41 million tons in 1996. And, it is expected to show a growth trend in coming decades.

Table 19 shows that domestic LPG supply grew at an annual average rate of 14.5 per cent during the period of 1991 to 1996, while gasoline outputs grew at 6.4 per cent during the same period. A remarkable change was in the LPG import sector, which recorded an average growth rate even higher than 100 per cent and keeps growing recently. Now, imported LPG has a very high share in total LPG supply.

Table 19 Selected Petroleum Products Supply in China
Ten Thousand Tons

	LPG (Domestic)	LPG (Import)	Gasoline (Domestic)
1991	303.7		2403.72
1992	349.6	1.9	2726.13
1993	410.14	68.12	3160.43
1994	442.69	96.65	2854.13
1995	540.53	232.55	3051.56
1996	598.77	355.03	3280.6
Average Growth Rate	14.5%	173.3% (1993-1996)	6.4%

Source: China Energy Statistical Yearbook 1991-1996

Table 20 shows the gasoline utilisation in various sectors. The shares in particular sectors did not change much, which strongly demonstrates the planned distribution in this area.

Table 20 Gasoline Utilisation by Sector in China

	Industry	Residential	Transport	Other
1991	29%	1%	32%	38%
1992	27%	1%	32%	39%
1993	27%	2%	29%	42%
1994	28%	2%	33%	37%
1995	28%	2%	34%	36%
1996	28%	3%	31%	38%

Source: China Energy Statistical Yearbook 1991-1996

However, Table 21 shows a quite different trend. LPG consumption increased rapidly of which average growth rate was 25 per cent for the increasing supply. Residential consumption shared 76 per cent of the total consumption, the growth rate of which was 28 per cent. LPG's growth implied the demand potential and possibility of rapid growth supply under free market condition.

Table 21 LPG Utilisation by Sector in China
Thousand Tons

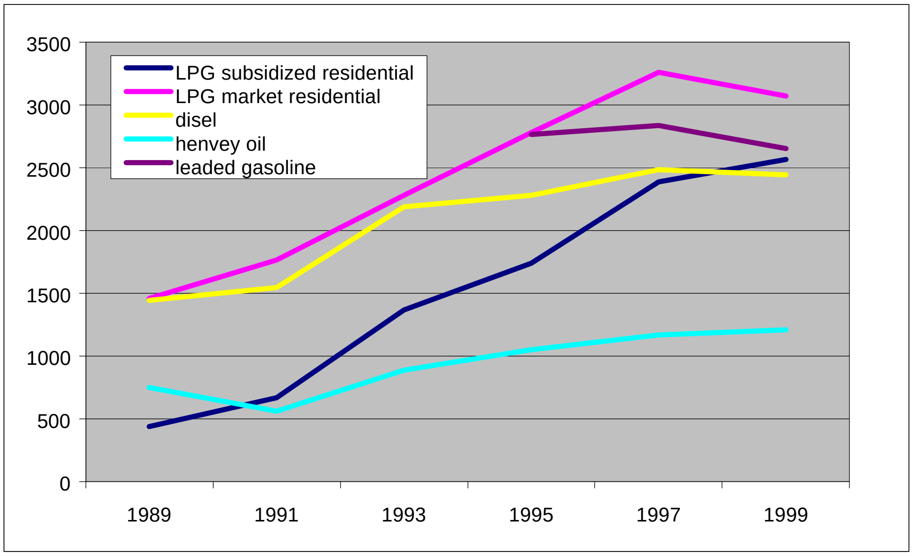
	Total	Industry	Residential	Other use
1991	3009	826	2017	166
1992	3576	1084	2392	100
1993	4997	1560	2990	446
1994	5699	1660	3850	189
1995	7491	1907	5340	245
1996	9298	1745	7035	518
Average Growth Rate	**25%**	**16%**	**28%**	**26%**

Source: China Energy Statistical Yearbook 1991 - 1996

Oil industry is monopolised by four stated-owned corporations, namely, China National Petroleum Corporation (CNPC), China National Offshore Oil Corporation (CNOOC), Sinopec, and SSPC. The government decided oil and petroleum products prices. The only exception is CNOOC, which focus on offshore area and its crude oil price is the same as that of international oil market initially.

As the international competition grows, the demand for price liberalisation is high. "Dual-track price" policy was undertaken in oil industry in 1980s. The dilemma is the government has to consider both up-stream and down-stream industry, both being stated-owned. Price is directly connected with profitability. So price adjustment always needs long-time negotiation. However, as import of oil and petroleum products increased, the price rose quickly in the recent decade as shown in Table 18. With low oil price from 1997, petroleum products price dropped, too, which partially reflects that petroleum products price has integrated into international market.

Figure 17 Petroleum Products Price Trend in China
Yuan/ton



Source: China Energy Prices Database 1989-1999, China Price Information Center

Government dominates pricing practices in petroleum area. The implementation of "Dual-track price" policy in 1980s partly liberalised petroleum products price in some areas. However, government controls the whole price system. As reflection of market demand, actually regulated price is quite close to the international price, and even higher in some cases. As the equalisation with the international market prices, petroleum products price could be completely liberalised in the future.

NATURAL GAS

Natural gas shared 2 per cent of total primary energy supply in 1996, which was 20.1 bcm with an average annual growth rate of 4.6 per cent over the period from 1991 to 1996.

Based on the new exploration by CNPC in Tarim and other natural gas fields, natural gas shows a brighter prospect than oil. Like the oil industry, state-owned corporations control natural gas industry. The environment has changed recently while LNG project would be built in Guangdong province using foreign investments.

As Table 22 presents, natural gas in China was mainly used in industrial sector which accounted for 82 per cent of total natural gas consumption in 1996 and its growth rate was highest compared with others. Although the growth rate in generation sector was 3 per cent, the total generation consumption share was just 4 per cent, while residential sector counted for 11 per cent and others 3 per cent. This natural gas share does not represent the real demand for insufficient supply. The utilisation structure shows a strong planning colour.

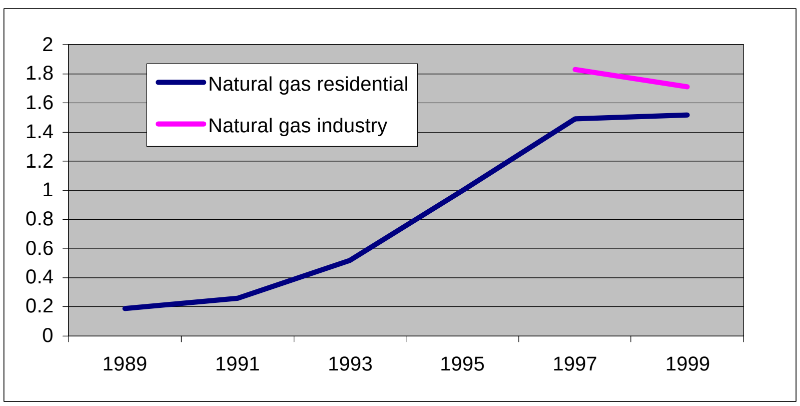
Table 22 Natural Gas Utilisation in China
Billion Cubic Meters

	Total	Industry	Residential	Generation	Other use
1991	15.58	12.01	1.81	0.64	1.12
1992	15.63	11.67	2.15	0.65	1.16
1993	16.60	12.52	1.73	0.82	1.53
1994	17.08	13.81	2.00	0.83	0.45
1995	17.35	14.31	1.94	0.79	0.31
1996	17.92	14.66	1.97	0.75	0.55
Average Growth Rate	2.8%	4.1%	1.7%	3.0%	-1.3%

Source: China Energy Statistical Yearbook 1991-1996

As a primary energy source, natural gas price was kept low for a long time. The price rose from 1980s, which was decided by government. Natural gas in residential sector was highly subsidised in the past. With the removal of subsidies, the prices rose in the recent decade.

Figure 18 Natural Gas Price Trend in China
Yuan/m³



Source: China Energy Prices Database 1989-1999, China Price Information Center

Natural gas industry is typically operated by a central-planned mechanism. Government and state-owned corporation control the whole process including exploration, production and distribution. Government is involved in every activity in pricing practices. However, as the development of LNG project goes ahead, it is possible to liberalise natural gas price integrated with international market.

ELECTRICITY

Electricity industry has grown rapidly accompanying economic development, supplying 72.5 per cent of final energy consumption in 1997. The electricity outputs rose at 8.6 per cent growth rate over the period from 1987 to 1997 with 8.8 per cent growth rate for thermal power plants and 6.9 per cent for hydropower station. The first nuclear power station came into operation in 1995 and other stations followed suit. Thermal power plants dominate electricity production, which shared 81.6 per cent of total electricity output.

Table 23 Electricity Production by Sector in China
Million kWh

	Total	Hydropower	Thermal	Nuclear
1987	497321	100229	397092	
1989	584675	118454	466221	
1991	677494	124845	552649	
1993	836429	150743	685686	
1995	1006948	186772	807343	128.33
1997	1134204	194571	925215	144.18
Average Growth Rate	8.6%	6.9%	8.8%	6.0%

Source: Overseas Electric Power Industry Statistics 1999, Japan

As Table 24 shows, the industrial sector is the biggest electricity consumer, which accounted for 73 per cent of total electricity consumption. However, it is on the decline. Instead, electricity consumption in residential sector increased with its share from 7 per cent in 1987 to 11 per cent in 1997.

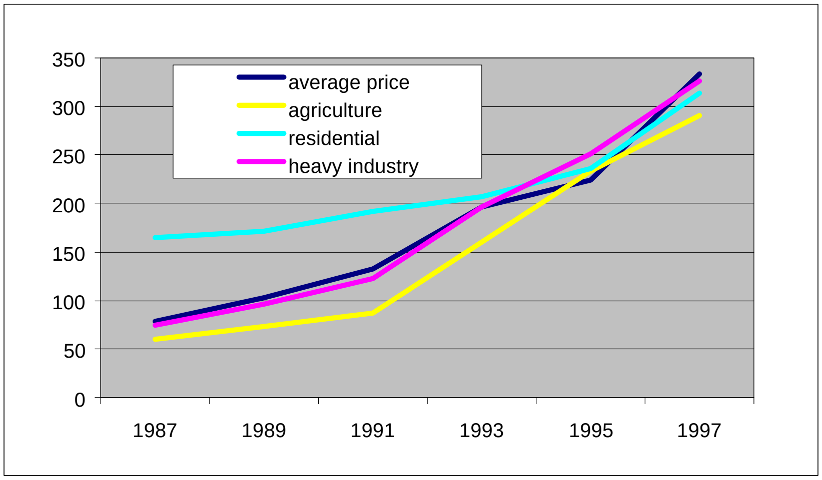
Table 24 Electricity Consumption by Sector in China

	Industry	Agriculture	Residential	Others
1987	81%	7%	5.5%	6.5%
1989	80.2%	6.9%	6.5%	6.4%
1991	77.8%	6.9%	7.9%	7.4%
1993	76.7%	6.3%	8.9%	8.1%
1995	74.8%	6.2%	10.2%	8.8%
1997	73%	6.2%	11.3%	9.5%

Source: Overseas Electric Power Industry Statistics 1999, Japan

Power sector is operated under monopolistic system. State Power Corporation owns grids and most of power stations. Most of the activities in power sector and price are decided by the government. With increasing initial cost of new power plants and market impact, the electricity price increased quickly. Electricity consumption in agricultural sector was subsidised in the past in order to improve agricultural output. But the subsidies have been removed recently and led electricity price to the same level in all sectors.

Figure 19 Electricity Price Trend in China
Yuan/MWh



Source: Overseas Electric Power Industry Statistics 1999, Japan

In 1980s' power was extremely short of supply. Energy related policies aimed to increase the power supply. One of them was investment-recovery electricity price policy, which promoted investment activities significantly for the non-risk payback. Accompanying new power plant construction, electricity price rose significantly.

After about ten years of large-scale power plant construction, power supply has basically met the demand, even there being surplus in some areas. Short supply happens just for peak-load period or some small particular areas. For non-risk payback, construction cost increased considerably, which led to very high electricity price in particular power plants. Electricity price regulation will be changed in order to reduce investment and to improve power plant performance. The major rule is to shift former investment-recovery electricity price to competitive price decided by the market.

Government will still be the regulator and dominate electricity pricing practices. However, the price will be more market-based.

INDONESIA

Indonesia has implemented subsidisation in the provision of energy commodities as a realisation of its social objectives in the policy, especially for oil products, which has been heavily subsidised. Since oil is the dominant fuel in its energy sector, this has consequently reduced the development of other energy commodities.

The Indonesian energy policy asserts that the energy price should be adjusted in a planned and deliberate manner that it reflects market mechanism. However, it must also ensure the protection to consumers and the equitable distribution of welfare.

Domestic fuel prices in Indonesia during the last two decades is shown in Table 25 below.

Table 25 Recent Indonesian Domestic Fuel Prices

Type of Fuel	Unit	1985	1990	1995	1998
Regular leaded gasoline	Rp/litre	385	450	700	1000
Premium leaded gasoline	Rp/litre	440	560	870	1300
Kerosene	Rp/litre	165	190	220	220
Automotive diesel oil	Rp/litre	242	245	380	550
Industrial diesel oil	Rp/litre	220	235	285	285
Fuel oil	Rp/litre	220	220	220	220
Jet oil	Rp/litre	330	330	400	400
LPG	Rp/kg	360	612	566	1336
Sub-bituminous coal	Rp/ton	n.a	n.a	n.a	93000
Steam coal (export)	US$/ton	n.a	50.10	n.a	n.a
Coking coal (export)	US$/ton	n.a	50.00	n.a	n.a
LNG (export)	US$/MMBTU	4.88	3.74	3.00	3.39

Source: Ministry of Mines and Energy, Indonesia

The supply of petroleum products and crude oil slightly decreased in 1994, then increased constantly from 30,244ktoe to 38,972ktoe in 1998. In the same period, the consumption increased from 32,041ktoe to 39,233ktoe. During this period, the price of petroleum products remains constant until 1998, when the government announced new prices.

COAL

Approximately 75 per cent of Indonesia's coal production is exported. Japan is the largest importer with 25 per cent share of this amount.

Coal supply decreased in 1994 and subsequently increased steadily from 4,691ktoe to 9,064ktoe in 1998, while at the same period the consumption increased from 1,196ktoe to 3,111ktoe.

The price for domestic and exported coal is determined in a market mechanism, either through a spot market or in a negotiated contract between buyers and sellers. However, in the contract between PT Tambang Batubara Bukit Asam (a coal producer) and PT Suralaya electricity generating company, the government intervenes with the aim at limiting price increase.

PETROLEUM PRODUCT

The cost of supply is classified into cost of natural resource, extraction cost and transportation cost. Oil products are derived from several stages of crude refining process, and through some additional processes to suit their specifications to the market demand. They are obtained from production of domestic refinery and imports. Eight oil refinery plants are operating in Indonesia with a total of about one million barrel crude throughput, which spreads in the main islands of Sumatera, Java, Kalimantan and Irian Jaya. Imported oil products are usually kerosene and automotive diesel oil (ADO).

The level of subsidisation of oil products is related to the production cost. The production cost consists of the cost of supplying crude oil to the refinery, capital cost of the refinery, and the operating cost. Although crude oil is partly supplied from domestic crude oil, the cost of supply is in US dollar. Therefore, the change in oil price and foreign currency greatly influence the production cost. Based on the average production cost, each oil product is given a price based on its own API gravity, consumption and the level of subsidisation. Table 26 below indicates the present oil products prices that were determined based on the average cost of Rp 950/litre, as was announced by the Minister of Mines and Energy on May 15, 1998.

Table 26 Indonesian Oil Product Prices Based on May 15, 1998 Presidential Decree

Oil Product		Price [Rp/litre]
Avgas (for aviation)		600
Avtur (for aviation)		600
Regular gasoline		1000
Kerosene		280
Automotive diesel oil (ADO)		550
Industrial diesel oil (IDO)		500
Fuel oil (FO)		350
LPG	[Rp/kg]	1500

Source: Pertamina, 1998

NATURAL GAS

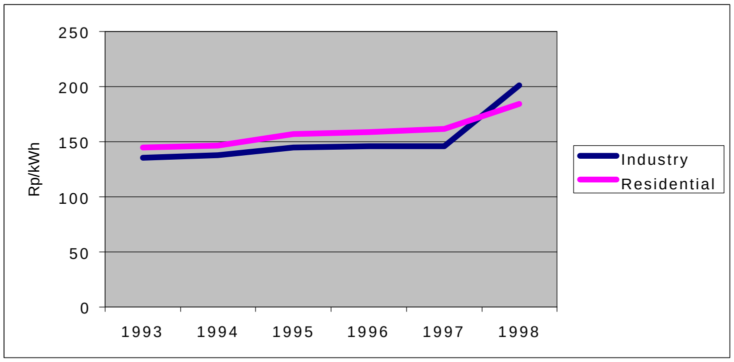
When it was first utilised for fertiliser industry in 1963, the price of natural gas was 30 per cent of the prevailing crude oil price. Initiated by the first commencement of LNG exports to Japan in 1978, it increased to around 90 per cent of crude oil. At present, the price is determined based on its netback value, which reflects all the cost associated with substituting to alternative fuels. The domestic price of natural gas is based on selling contracts, which are set by the government.

The natural gas supply has increased steadily from 22,238ktoe in 1993 to 31,872ktoe in 1997, then declining sharply to 27,089ktoe in 1998. Similarly, the consumption has increased from 6,134ktoe in 1993 to 7,917ktoe in 1997 before decreasing to 7,332ktoe in 1998.

ELECTRICITY

More than 60 per cent of electricity generated is consumed in the main island of Java, constituting a higher operation cost in the electricity grid system outside of Java. The electricity tariff is determined according to the State Law No. 15 of 1995 about electricity, which asserts large subsidy. The tariff is set uniform across regions, with cross subsidy between Java and Outside Java systems, and among sectors. Largest subsidies are given to small residential consumers, while large residential consumers are not given any subsidy. Electricity price during the period of 1993-1998 is in Figure 20.

Figure 20 Electricity Prices in Indonesia
1993-1998



JAPAN

Japan is one of the largest energy consumers in the world, and with few domestic energy resources, imports around 80 per cent of its primary energy requirement. Since energy is largely imported, energy prices in Japan are exposed to exchange rate movements in yen since most energy import contracts are denominated in US dollars. The domestic Japanese energy market is currently being restructured. As an energy importer, Japan does not impose any significant import tariffs, however a number of domestic energy taxes and levies are designed to moderate energy consumption.

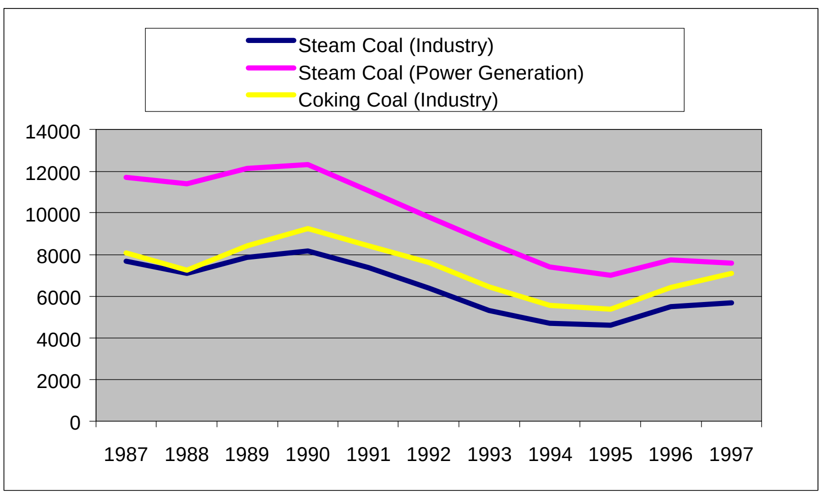
COAL

Japan is the largest coal importer by far, which accounts for 28 per cent of total world coal import in 1997. The import coal counted 87,190 billion kcal in 1998 with 2,089 billion kcal for domestic production. Coal imports are from Australia, the United States, China, and so on. Domestic coal industry is heavily subsidised partly for security and technology improvement.

Coal is mostly used for power generation and high-energy intensive industry such steel, cement and paper industry.

As import coal shares the high proportion of total supply, the coal price in Japan follows international market. Price of imported steam coal is determined by the negotiation between Australian coal companies and Japanese electricity companies. This negotiated price of coal is called "bench-mark" price and it has become a reference price since late 1980s. As Figure 21 indicates, coal price shows a declining trend.

Figure 21 Coal Price Trend in Japan
Yen/ton



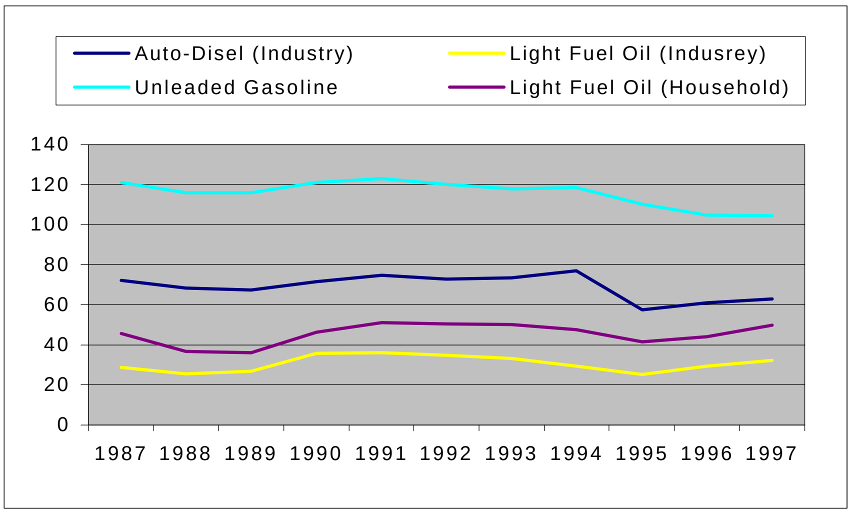
Source: APERC Energy Database

PETROLEUM PRODUCTS

Oil shared 60.3 per cent of final energy consumption and mostly comes from Middle East. Overseas oil explosion by Japanese companies is an important aspect for supply security. Japan government has started to introduce policies to ensure that the operational of the domestic market in petroleum products is comparable with international standards of performance. The intention is to reduce or abolish government interference in non-emergency periods.[9]

In March 1996, the wholesale pricing system for the petroleum products of two Japanese major oil companies, Idemitsu Kosan and Japan Energy was revised for in preparation of changing market environment after the Provisional Measures Law on the Importation of Specified Petroleum Products was revoked. The pricing system was designed making it closer to international standards. Thus, especially the price of gasoline was declining largely. In late 1998, after the law was removed, gasoline price became a half of that of early 1996. Implied tax in the final price of gasoline and diesel was outstandingly large.

Figure 22 Petroleum Products Price Trend in Japan
Yen/litre



Source: APERC Energy Database

Domestic oil refining and marketing activities of the Japanese petroleum industry were deregulated in the period 1987 to 1992, based in the principle that the industry should be free to compete domestically except during emergencies, when government controls would apply. A second phase of deregulation followed from April 1996, with the aim of improving efficiency in the domestic petroleum industry. The new pricing structure established retail margins in line with international levels for petroleum products. Gasoline retail margins fell as a result. Further change appears inevitable.[10]

NATURAL GAS

Natural gas accounted for 12.3 per cent of total primary energy supply with growth rate 4.6 per cent over the period from 1988 to 1998 for energy security and emission reduction. Most

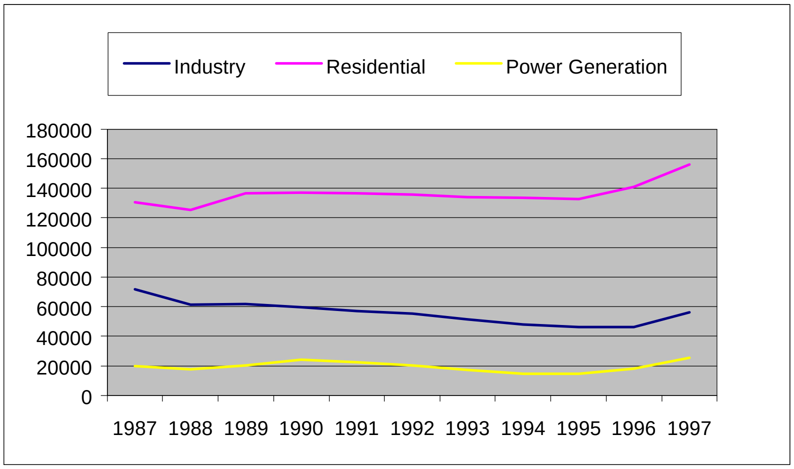
[9] IEA, Energy Policies of IEA Countries: Japan 1999 Review, OECD/IEA, 1999

[10] IEA, Energy Policies of IEA Countries: Japan 1999 Review, OECD/IEA, 1999

natural gas was used for power generation while LPG was major aspect compared with pipeline network.

Until 1994, the Gas Utility Industry Law defined service area for general gas suppliers, and suppliers supplied gas in these areas at authorised rates system. The law allows large customers to negotiate with general gas suppliers in March 1995. The large consumers, mostly industrial customers, are defined to have a volume of more than two million cubic meters of gas per year and the price is decided through negotiation between the gas companies and the large consumers. Conventional authorised rates system has been applied for small-scale consumers as before.

Figure 23 Natural Gas Price Trend in Japan
Yen/million kcal

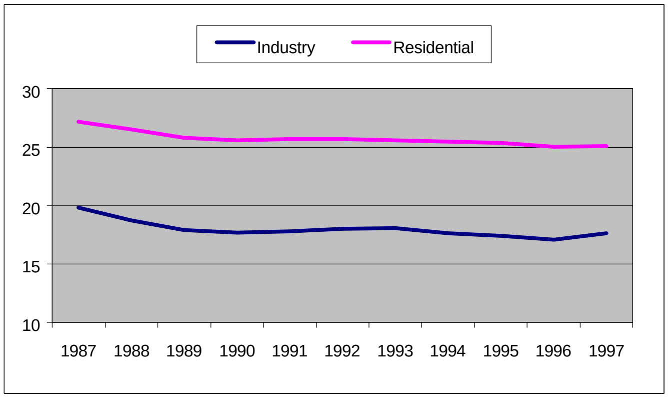


ELECTRICITY

Electricity outputs counted for 1,046,288 million kWh in 1998 with average growth rate 3.3 per cent during the period from 1988 to 1998. Thermal power plant contributed 58.1 per cent of total electricity production with 9.8 per cent for hydropower and 31.8 per cent for nuclear power. Electricity demand grew rapidly especially in residential and commercial sector.

There are ten vertically integrated companies with regional monopoly power in Japan. In general, the electricity price is decided based on the electricity rates consist of a demand charge determined by the contracted capacity and an energy charge that varies with actual consumption. Beyond the system, Yardstick Formula was introduced with January 1996 rate system reforms to promote operating efficiency by encouraging indirect competition among the electric power companies. Since cost-curtailing assessments on the companies in the worst-performing group is conducted every time the rate system is reformed, it is expected to provide the electric power companies with an incentive to improve their operating efficiency more than the other companies before the next rate system reform. 8.7 per cent amount of the final electricity price becomes tax. As Figure 24 shows, the electricity price shows decline trend.

Figure 24 Electricity Price Trend in Japan
Yen/kWh



Source: APERC Energy Database

KOREA

The Korean energy market has traditionally been heavily regulated, as the government has pursued policies to provide a stable energy supply at low prices. The objective of these energy policies was to control inflation, ensure industrial competitiveness, economic growth and provide social equity.[11] The energy sector was dominated by state owned monopolistic organisations, and widespread pricing regulations, which were used as the vehicle to achieve the energy policy objectives.

In 1997 the Korean government commenced a programme of deregulation with the complete market liberalisation of oil price commencing in 1997, allowing the market to determine domestic oil prices. The government also announced the deregulation of the gas and electricity sectors around 2003. This has placed the majority of the Korean energy market in transition, as the government gradually privatises and deregulates the energy market.

The impetus for deregulating the energy market reflected recognition of the inefficiency associated with heavily subsidised energy prices. Although subsidising energy prices contributed to industrial, and therefore economic, growth in Korea, it also resulted in a distorted energy intensive industrial structure with poor energy efficiency and environmental pollution.

COAL

Import coal plays the dominant role while domestic coal production declines in recent years for the rising production cost. Australia is the dominant import coal supplier. In the demand side, steel industry consumes the major import coal along with cement industry. As the capacity of steel and cement industry rises, coal consumption is expected to increase.

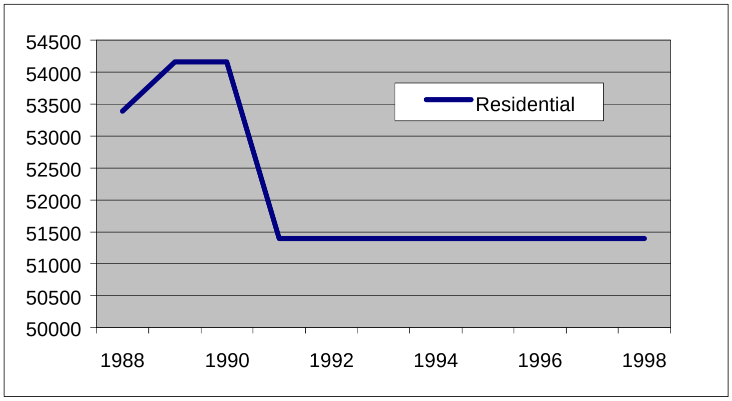
The government currently enforces a ceiling price for domestically produced anthracite for social reasons, since the main users of anthracite are relatively poor households with limited

[11] Cho, G.L., Korea Energy Market in Transition, Proceedings of the APERC's Workshop on Energy Pricing Practices, Tokyo, 28-29 Sep. 1999

access to alternative energy sources. Therefore no valued-added tax (VAT) is payable on anthracite (domestic produced or imported).

Korea's imports of bituminous coal are purchased on the international market, either as a spot market or through longer-term contracts. These prices are influenced to some extent by the benchmark prices established from negotiations between Japan and exporting countries such as Australia and Canada. The Korean government does not directly participate in these negotiations, but imports are currently subject to a 1 per cent import tariff, and a 10 per cent VAT.

Figure 25 Coal Price Trend in Korea
Won/ton



Source: APERC Energy Database

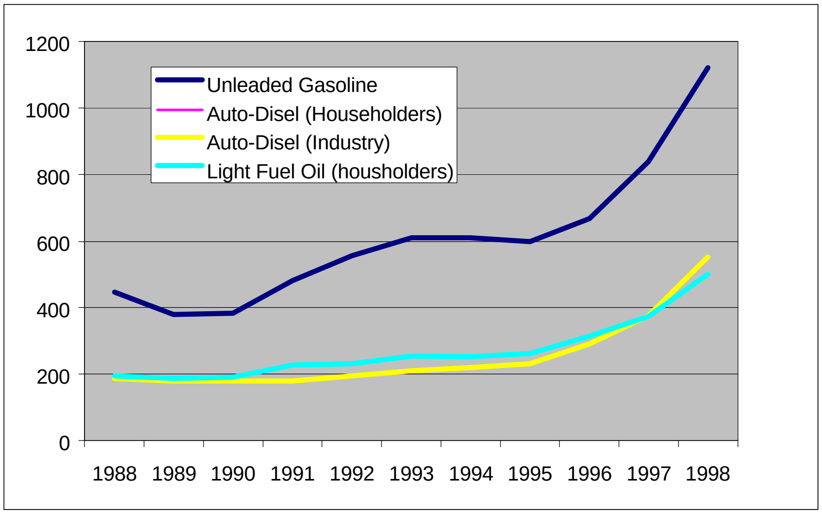
PETROLEUM PRODUCTS

Oil is the most important fuel accounting for about 60 per cent of total primary energy consumption, which is imported mainly from Middle East. With the high economic increase, petroleum product demand rose rapidly.

Korean government began deregulating the oil market in 1997, with the fully deregulated market operating since February 1998 (except for LNG).

There are a number of taxes and levies that apply to crude oil. These include a 5 percent customs tariff, 10 percent VAT and a special surcharge of US$1.70 per barrel that is paid into a Petroleum Business Fund. Additionally, there are various excise taxes applied to oil products, ranging from 150 per cent for gasoline, 20 per cent for diesel and 10 per cent for LPG. The lower excise tax aims to encourage economic growth by reducing production and transportation costs.

Figure 26 Petroleum Products Price Trend in Korea
Won/litre



Source: APERC Energy Database

NATURAL GAS

Natural gas supply in Korea mainly relies on import from South East Asia and now shifts to the Middle East. Power generation sector consumed 5.2 million tons LNG with 45.7 per cent share of total natural gas consumption in 1998 while town gas shared 50.7 per cent.

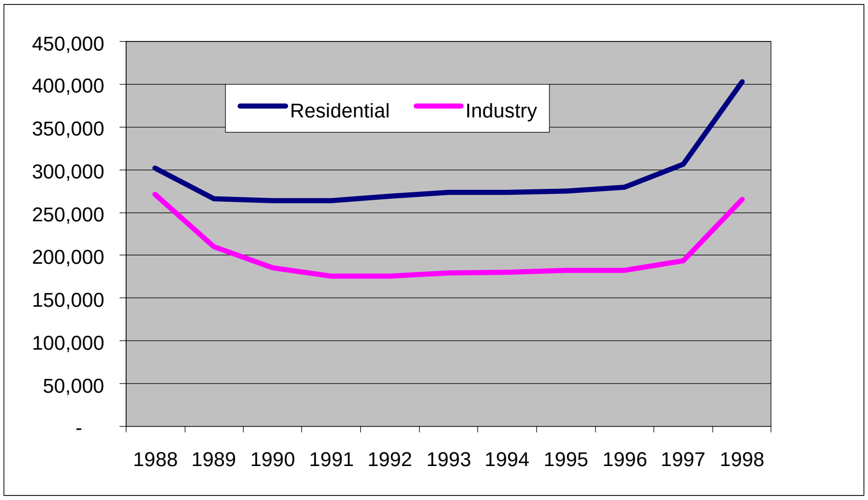
Korea's natural gas industry consists of the wholesale market (KOGAS) that imports and distributes natural gas to the regional companies, and the retail (regional city gas companies) that supplies end-users. KOGAS also supplies end-users consuming more than 100,000 cubic meters per month, as well as the power generation sector (KEPCO). The wholesale price charged to city gas companies, KEPCO and large end-users is subject to approval by the Minister of Commerce, Industry and Energy. For power generation, the import price is adjusted on a monthly basis. The retail price of city gas to end-users varies according to the import gas price and prevailing exchange rates. City gas prices are adjusted every quarter, but must be within 3 per cent of the previous price.

The price that is ultimately determined will reflect a number of factors, including:

- The purchase and offshore transportation costs for LNG, which make up around 75 per cent of the final supply cost;
- Pipeline transportation, re-gasification, management and maintenance costs;
- Taxation, including a 10 per cent VAT, 1 per cent import tariff on CIF LNG import price, 5.58 Won/m^3 of import surcharge on regasified gas, and a special excise tax of 10 per cent on CIF LNG price.

A number of levies and charges are included into the final price. For example, City gas companies are required to pay a safety management and import charge. Additionally, cross-subsidies exist between gas tariffs for power generation, City gas and regional retail prices. In terms of the regional retail prices, it is arguable whether regional cost differences can be incorporated into the price, suggesting that any regional pricing differences are either arbitrary, or reflect other social goals. Retail prices are also differentiated in terms of the customer class, which includes residential cooking, residential heating, commercial, general heating, general cooling, industrial, building cogeneration and regional cogeneration. These different tariffs (cross subsidies) are applied for primarily social equity reasons.

Figure 27 Natural Gas Price Trend in Korea
Won/million kcal



Source: APERC Energy Database

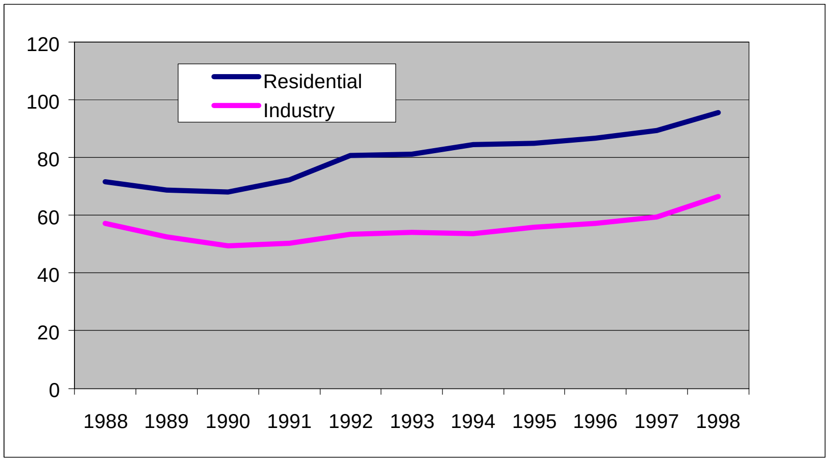
ELECTRICITY

Electricity production accounted for 193.5 billion kWh in 1998 with average growth rate 10 per cent over the period from 1988 to 1998, which manufacturing consumed 53.7 per cent of total output in 1998. Thermal power plant shared 65.1 per cent of total installed capacity while 7.2 per cent for hydropower stations and 27.7 per cent for nuclear power plants.

The electricity price is divided into six different consumer groups, and prices for industrial and agricultural consumers are lower than other consumers. Compared with other economies, Korea's industrial electricity price has been heavily subsidised and the cost to industrial consumers, in 1997, was about 8 per cent below the OECD average.[12]

[12] Cho, G.L., Korea Energy Market in Transition, Proceedings of the APERC's Workshop on Energy Pricing Practices, Tokyo, 28-29 Sep. 1999

Figure 28 Electricity Price Trend in Korea
Won/kWh



Source: APERC Energy Database

Until 1996, the publicly owned KEPCO electricity utility maintained a rate of return of over 8 per cent, however increased depreciation cost and increases in fuel costs after 1996 lowered the rate of return to less than 5 per cent. The lower return rates have weakened KEPCO's financial basis, with a burdening debt problem.

The decrease in real electricity prices has entrenched Korea's energy intensive industrial structure as the share of electricity in production costs has fallen. Energy intensity measured per value added in the manufacturing sector increased by over 25 per cent between 1988 and 1998.[13] The electricity price is also subject to a 10 per cent VAT, in addition to the separate taxes and tariffs applicable to the fuel inputs (coal, oil and gas).

MALAYSIA

Energy pricing mechanism in Malaysia is a combination of market-driven and regulated prices. The prices are determined by the government or proposed by relevant utilities, and subject to government approval.

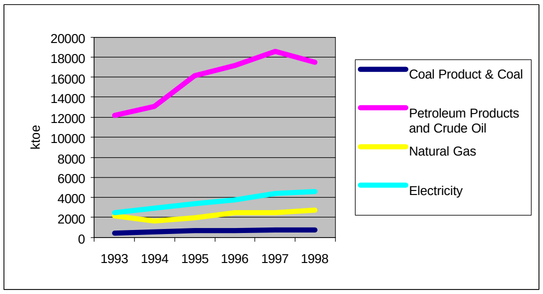
PETROLEUM PRODUCTS

The petroleum product supply increased from 16,681ktoe in 1993 to 23,458ktoe in 1997, and decreased to 20,726ktoe in 1998. The consumption also increased from 12,165ktoe in 1993 to 18,577ktoe in 1997 before declining to 17,487ktoe in 1998, which was most likely caused by the

[13] Cho, G.L., Korea Energy Market in Transition, Proceedings of the APERC's Workshop on Energy Pricing Practices, Tokyo, 28-29 Sep. 1999

financial crisis that struck the Southeast Asian region. Figure 29 shows final energy consumption in Malaysia during 1993-1998 period.

Figure 29 Final Energy Consumption in Malaysia
1993-1998



Source: APEC Energy Database

The price of petroleum products, which are internationally traded, are closely related to the average posted prices of Singaporean oil companies, but price variations and margin are controlled by the Automatic Price Control Mechanism by the Ministry of Energy, Post and Telecommunications. Different taxes are applied on premium leaded gasoline and on diesel oil.

NATURAL GAS

Natural gas has been supplied and consumed more than coal in Malaysia. The supply dropped to 10,658ktoe in 1994, and subsequently climbed to 27,181ktoe in 1998, while the consumption dropped to 16,77ktoe in 1994, then increased to 27,26ktoe in 1998, as indicated in Figure 29 above.

At the early period of gas development, the government fixed the price. Today, gas pricing for production, purchase price from the offshore gas producer is pegged to the medium fuel oil (MFO) prices ex-Singapore. Gas pricing is made consistent with objectives of the national policy to develop the utilisation of gas.

ELECTRICITY

Due to geographical set-up, the electricity utilities are separated according to areas: Tenaga Nasional Berhad (TNB) for Peninsular Malaysia, Sarawak Electricity Supply Corporation (SESCO) for Sarawak, and Sabah Electricity Board (SEB) for Sabah, resulting in different production cost per kWh for the three areas. Utilities in Peninsular Malaysia and Sabah are under control of the government, while Sarawak utility depends on the Sarawak State.

MEXICO

Mexican energy policies are geared towards ensuring the availability of reliable commercial energy sources at minimum costs, to facilitate the sustained economic growth that is needed in the Mexican economy. At the same time, energy policies emphasise the importance of minimising negative environmental externalities, and guaranteeing sustainable energy development for the benefit of future generations.

Mexico's energy needs, is predicted to grow in the coming decade. Oil and natural gas likely will remain the dominant energy sources through 2020, accounting for well over 80% of total energy consumed. As an economy that is rich in domestic energy resources, particularly crude and natural gas reserves, Mexico exports over 40 per cent of its total energy production (mainly crude oil). Mexican energy pricing policies are set with the purpose of achieving a number of fundamental objectives, including:

- Fiscal revenue to facilitate government functions;
- Environmental and resource sustainability;
- Social policy goals, such as energy subsidies for poor regions;
- International competitiveness;
- Efficient energy consumption
- Adequate investor returns
- Transparent pricing process

COAL

Coal provides about 11 per cent of Mexico's total electricity requirements. Recoverable coal reserves as of late 1998 stood at 1.3 billion short tons. Coal is used primarily for the production of steel, as well as supplying coal-fired plants in the region. The U.S.-based Mission Energy, which purchased the previously government-owned company Minera Carbonifera Rio Escondido (MICARE) when it was privatised, is now Mexico's largest coal producer. A small volume of imports from the United States, Canada, and Colombia augments domestic coal supplies. Coal demand is expected to increase by about 3.2 per cent annually in the coming decade, mostly for the power generation and industrial sectors.

PETROLEUM PRODUCTS

Mexico's state oil company, PEMEX, the world's sixth largest oil company, controls virtually all areas of the oil and gas sectors. PEMEX involves in exploration, development, refining, transportation, storage, and distribution of the country's hydrocarbons. Foreign participation in Mexico's upstream sector is limited to service and performance contract arrangements and turnkey drilling contracts. PEMEX is divided into four primary areas: exploration and production; refinery; gas and basic petrochemicals; and petrochemicals.

Mexico's proven oil reserves are estimated at about 28.4 billion barrels. In 1999, Mexico produced about 3.4 million barrels per day (bbl/d) of oil (2.9 million bbl/d of crude), and consumed about 1.94 million bbl/d. Net oil exports amounted to 1.45 million bbl/d, of which 1.36 million bbl/d went to the United States. Petroleum export revenues in 1999 were estimated at $8.6 billion, up from $7.14 billion in 1998.

Historically low oil prices in 1998-99, and Mexico's great dependence on oil revenues, prompted it to support OPEC's production cuts in 1998-2000. Mexico has played an active role among OPEC and non-OPEC oil producers, cutting its own production and reducing crude oil exports by pushing more Mexican crude into domestic refineries while cutting back on oil product imports. Mexico presently has a network of about 34,000 miles in crude oil and product pipelines. In 2000, PEMEX plans to spend $500 million to add another 1,260 miles to the network.

Although Mexico produces about 5 per cent of the world's oil, it does not have sufficient refinery equipment or technology to supply its domestic needs (about 500,000 bbl/d of gasoline, and about 270,000 bbl/d of diesel in 1999). Mexico therefore exports much of its crude oil to the United States, and then imports back about 130,000 bbl/d of refined oil. Mexican gasoline consumption is projected to grow by about 3 per cent annually for the next few years, PEMEX is planning to expand the economy's refining capacity to process heavy crude oil and to produce higher volumes of lighter fuels.

The market price mechanism offers the elements to fix the export price of the Mexican crude oil as a function of the market. The mechanism also takes into consideration the characteristics and yields of the Mexican crude oil against their main crude type competitors in the related market. There are several ports of entry into Mexico, through which LPG is brought from the U.S. market. The ports of entry by land are the cities of: Tijuana, Mexicali, Ciudad Juárez, Piedras Negras, Reynosa and Matamoros. The port of entry by sea is the port of Pajaritos. The reference market used to calculate the opportunity cost for the domestic supply of LPG is that of Mont Belvieu, Texas in the U.S.

The main reference crude oil prices used to establish the price of the Mexican types of crude oil are, for the Gulf of Mexico Coast and the U.S. West Coast in California: the WTI, WTS, ANS and LLS. For the European market: the Brent; and for the Far East market: the Oman and Dubai crude oil types.

The first component in setting the LPG price is given by the opportunity cost of a mix of C3s (propane) and C4s (butane) of Mexican product compared against the Mont Belvieu market price in the U.S. Gulf Coast.

Adding the logistics, terminal and freight costs, define the PEMEX invoice price (producer's price). Finally, a commercial margin and taxes are added up to the end user price. The same scheme applies for gasoline. The opportunity cost for regular unleaded gasoline in the U.S. Gulf Coast market is established as the reference price for PEMEX. And accounting for the losses, margins, freight and taxes, we arrive at an end user price. Magna Sin is the Mexican gasoline brand in the domestic market equivalent to regular unleaded gasoline in the U.S. Gulf Coast.

NATURAL GAS

In the next ten years electricity demand, together with the country's policy for substitution of conventional fuels for cleaner ones, will drive gas consumption growth tendencies in Mexico. It is expected that over 80 percent of new installed capacity of electricity generation plants will be based on gas-fired combined cycle technology. The annual growth average in gas consumption in the years 1985 to 1998 was 3.0 per cent. An annual growth rate of around 9 per cent will be the norm for the 10-year period from 1999 to 2008.

Both gas and electricity consumption in Mexico will continue to grow due to privatisation efforts, growth in energy demand, advances in gas generation technologies, and growth in independent power production. Mexican tariffs on the imports of natural gas were eliminated in 1999, and this is viewed as a big opportunity for U.S. natural gas exporters.

The reference price for natural gas in Reynosa, at the border with the U.S., is defined by indexes published in the "Inside FERC's Gas Market Report" for natural gas delivered by Texas Eastern Transmission Corp. and Pacific Gas & Electric Gas Transmission-Texas. The port of entry cost in the city of Reynosa in the Northeast of Mexico establishes the opportunity cost for the domestic supply of natural gas.

The main production source is located in Ciudad PEMEX, in the State of Tabasco in the southeast of the country, where there is a high concentration of natural gas processing plants. Thereafter, the reference price for natural gas in Ciudad PEMEX (southeast of Mexico) is made equal to the price in Reynosa; plus the transportation costs from Reynosa to Los Ramones, a city in the mid-northern part of Mexico, less transportation costs from Cd. PEMEX to Los Ramones.

ELECTRICITY

There are two main electric utilities in Mexico, Comisión Federal de Electricdad (CFE), which has 34.8GW of installed capacity and distributes energy to around 80 per cent of the market, and Fuerza del Centro (LFC) which distributes electricity to the remainding 20 per cent but only generates about 2.3 per cent of total generation through 0.9GW of installed capacity. The remaining generation is derived from PEMEX and the private sector, generating 4.4 and 3.3 per cent of generation, respectively.

The general structure of tariff charges for electricity includes three types: fixed charges, demand charges and power charges. Fixed charges account for power commercialisation costs; demand charges account for investments due to power supply capacity, and power charges represent operation and maintenance due to consumption.

In some special instances, tariffs not necessarily include all of these charges. In such cases, costs associated with those charges not included, are added to the remnant charges. Specific use tariffs are defined for certain sectors such as residential, agricultural, public lighting, municipal water pumping and temporary services. There are also general use tariffs for low, medium and high voltage use. These general use tariffs are used for commercial and industrial purposes in low, medium and high voltages. Tariffs for commercial, industrial and municipal services, reflect the economical costs of generation, transmission and distribution, including those of external producers, and are adjusted according to the evolution of economical costs through time, considering regional and seasonal differences, productivity and the operational conditions of the system.

In Mexico, public utilities pay a fee to the Federal Government for the use of facilities and installations, determined annually and apportioned to funds for investment. In the end, the Ministries of Energy, Commerce and Finance approve the tariff proposals made by the public electric utilities. An important part of the authorization process involves confirmation that these proposals properly address the requirements for finance, service expansion and rational use of energy.

NEW ZEALAND

New Zealand has undertaken over the last decade a comprehensive reform of the energy sector. Former Government owned and operated electricity and gas monopolies have been either corporatised or sold to the private sector. The former vertical integration in both gas and electricity sectors has been dismantled to separate natural monopoly elements from those that are competitive, and a wholesale electricity market established. Historical electricity tariff cross-subsidies have disappeared, and consumers now pay an energy price more closely reflective of the true cost of supply - with increasingly intense competition driving costs down.

COAL

In international terms, the scale of the New Zealand coal industry is small. Coal production in 1998 was 3.3 million tonnes, with about 54 per cent consumed domestically and the rest exported. The largest coal producer is the state owned enterprise Solid Energy New Zealand Ltd (responsible for about two-thirds of production). Private operators produce the rest. There are no subsidies on coal, and all coal is sold by competitive contract.

About 32 per cent of domestic consumption was used in 1998 to generate electricity. The rest was consumed by the basic metals sector (32 per cent), other industry (24 per cent), with the commercial sector, transport, agriculture and households accounting for the rest.

With coal competing freely with other fuels for electricity generation, the amount used for this purpose has never been historically high due to relatively high coal production costs against the low long-run costs of hydro, and more recently, high efficiency combined cycle gas turbines burning domestic natural gas.

PETROLEUM PRODUCT

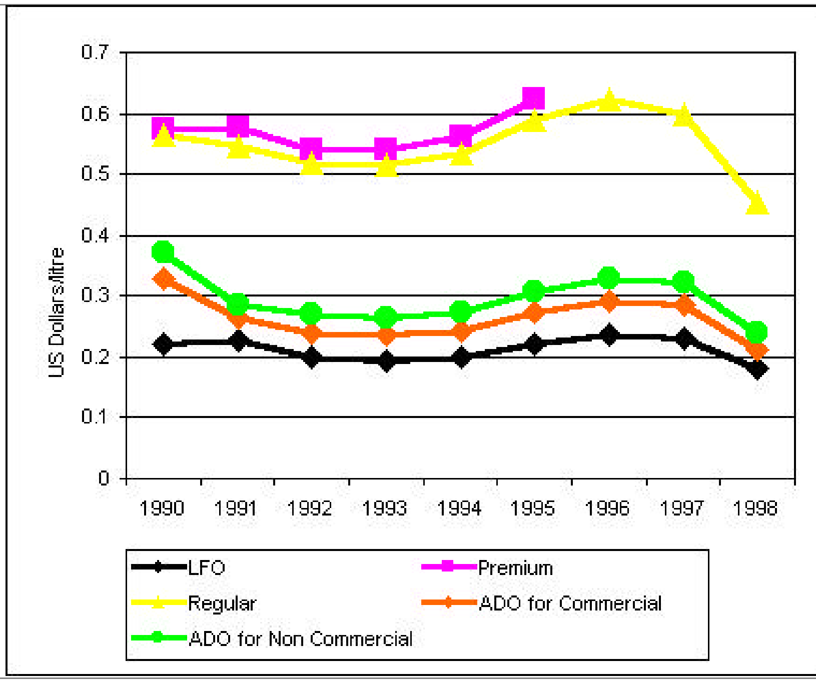
Petroleum provides around 32 per cent of total primary energy supply. New Zealand produces crude oil and condensate domestically, all in the Taranaki region. Although crude and condensate production has increased steadily since the early 1980s, there was a significant decline in 1998 compared to the previous year, suggesting a peaking of overall domestic production capability at around 90PJ (in the absence of new discoveries).

Deregulation of the petroleum industry in the late 1980s removed price control, government involvement in the refinery, licensing of wholesalers and retailers, and restrictions on imports of refined products.

From before industry deregulation, the government has had no ownership interests in petroleum distribution and retailing, which until the entry of Challenge Petroleum Limited (in April 1998) and Gull Petroleum (in December 1998) were dominated by four international oil companies: BP, Caltex, Mobil and Shell. Each international oil company, along with Fletcher Challenge Energy Ltd, has a stake in the New Zealand Refining Company Limited, which operates New Zealand's sole refinery at Marsden Point. They also own the bulk storage facilities as well as most of the retail outlets.

The trend of the past seven-year prices to end-use consumers is shown in Figure 30, where the prices were relatively constant between 5 to 6 US cent/litre for premium price and from 2 to 3 US cent/litre for diesel price.

Figure 30 Petroleum Product Price in New Zealand



Source: IEA Statistics, Second Quarter 1999

NATURAL GAS

Recently, mostly natural gas is used to generate electricity. The share of natural gas production used for electricity was around 31 per cent in 1990 as in Table 27. However, the share of natural gas used for electricity rose to around 40 per cent in 1997. Natural gas utilisation for other sectors like the industry sector, the household sector, etc. decreased to 60 per cent in 1997 from 69 per cent in 1990. Industry consumption was almost stable, namely around 620ktoe per year during the past seven years, while the household consumption was around 200ktoe per year.

Table 27 Natural Gas Production for Electricity in New Zealand

	Electricity		Others		Total
	ktoe	% share	ktoe	% share	ktoe
1990	1216	31	2694	69	3910
1991	1485	35	2774	65	4259
1992	1605	36	2910	64	4515
1993	1483	34	2908	66	4391
1994	1171	29	2930	71	4101
1995	1132	29	2742	71	3874
1996	1326	34	2608	66	3934
1997	1903	40	2801	60	4704

Source: APEC Energy Statistics 1977

Table 28 Natural Gas Consumption by Sector in New Zealand

	Industry	Residential	Others	Total
	ktoe	ktoe	ktoe	ktoe
1990	630	174	588	1392
1991	632	183	818	1633
1992	634	193	733	1560
1993	613	204	810	1627
1994	631	205	1029	1865
1995	589	210	1275	2074
1996	614	198	1486	2298
1997	845	221	1742	2808

Source: APEC Data Statistics 1977

Reform of the gas industry began in the 1987 when the Crown publicly floated 30 per cent of Petrocorp, through which the Government had managed its interests in the production, transmission and distribution of gas. The Government's remaining interest in Petrocorp, including the Natural Gas Corporation Limited (NGC), was sold in 1988.

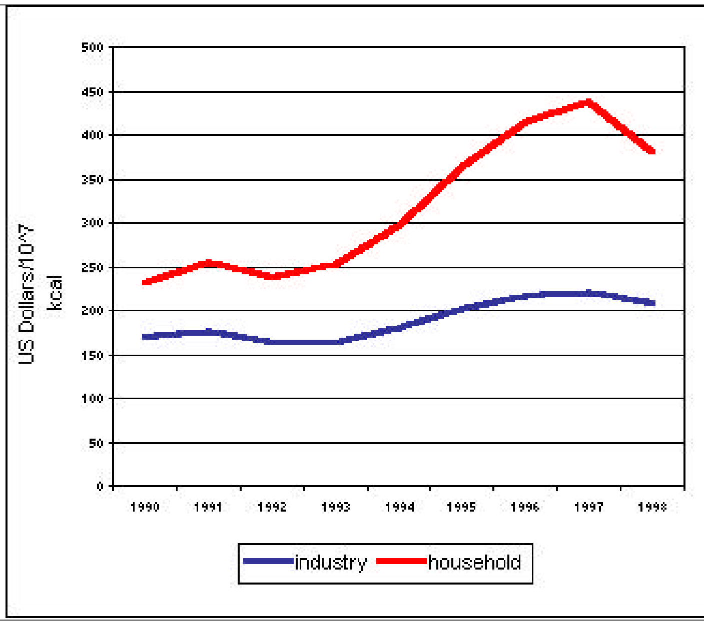
Currently, gas is entirely produced in the Taranaki region. There are currently eight fields producing oil and gas, with the Maui field continuing to dominate (71 per cent of gross gas production). Total gas production for the year ended March 1999 was 209.2PJ. The three major groups of users are petrochemicals, electricity generation and direct reticulated consumers.

NGC operates the gas transmission network and owns two-thirds of the 2,600km of high-pressure gas pipelines. Maui Development Limited (MDL) and NGC are the two transmission owners (with NGC operating MDL's pipeline). There are five distribution companies and six retailers in New Zealand.

The gas (and electricity) industries were deregulated in 1993 with, inter alia, the removal of gas franchise areas and the lapsing of wholesale gas price controls (retail price control has already lapsed). The industry in 1998 successfully concluded a voluntary third party access regime for the natural gas pipeline network.

The natural gas price for end user consumer especially for household and industry sector shows in Figure 31. It shows that the price for household was higher than industry. The household price was sharply rose to 438 US$/toe in 1997. However, industry consumption was relatively stable during the past seven years.

Figure 31 Natural Gas Prices to End-use Consumers in New Zealand



Source: IEA Statistics, Second Quarterly 1999

ELECTRICITY

The growth rate of electricity consumption during the past seven years was around 1.9 per cent per annum. More than 50 per cent of the total electricity consumption was consumed by residential consumers followed by the industry sector at around 40 per cent, and other sectors were less than 10 per cent as shown in Table 29.

Table 29 Electricity Consumption by Sector in New Zealand

	Residential		Industry		Other		Total
	ktoe	% share	ktoe	% share	ktoe	% share	ktoe
1990	1355	56.7	962	40.3	73	3.1	2390
1991	1361	55.3	991	40.2	111	4.5	2463
1992	1304	53.4	991	40.6	145	5.9	2440
1993	1392	55.0	1015	40.1	124	4.9	2531
1994	1411	54.7	1015	39.3	155	6.0	2581
1995	1396	51.6	1107	40.9	205	7.6	2708
1996	1430	51.3	1145	41.1	213	7.6	2788
1997	1482	54.6	1143	42.1	91	3.4	2716
Average Growth (%)	1.3		2.5		10.3		1.9

Source: APEC Energy Statistics 1977

Electricity was predominantly generated by geothermal, natural gas and hydro as shown in Table 30. The shares of those fuels were almost 30 per cent during the past seven years. The share of natural gas production of the total electricity production increased to 32 per cent in 1997 from 24.3 per cent in 1990. However, the share of coal production to total electricity production was only around 2.4 per cent in 1990, rising to 7.4 per cent in 1997.

Table 30 Electricity Production by Plant Type in New Zealand

	Coal		Geothermal		Natural Gas		Hydro		Total
	ktoe	% share	ktoe	% share	ktoe	% share	ktoe	% share	ktoe
1990	119	2.4	1690	33.8	1216	24.3	1980	39.6	5005
1991	55	1.0	1816	34.3	1485	28.1	1934	36.6	5290
1992	221	4.1	1793	33.1	1605	29.6	1796	33.2	5415
1993	107	2.0	1893	34.6	1483	27.1	1996	36.4	5479
1994	94	1.8	1768	33.6	1171	22.3	2229	42.4	5262
1995	165	3.1	1715	32.6	1032	19.6	2343	44.6	5255
1996	259	4.6	1798	32.1	1336	23.8	2214	39.5	5607
1997	441	7.4	1631	27.4	1903	32.0	1977	33.2	5952

Source: APEC Energy Statistics 1977

Although overall reform of the electricity is well advanced, 1998 saw some further major reforms. These were designed to increase competition in generation and to give smaller consumers a choice of electricity supplier in order to provide more competitive prices and improved services.

For the decade commencing in 1987, the electricity reforms included: corporatisation of the monopoly generator ECNZ (later split into two competing entities in 1995); elimination of the statutory government monopoly on generation – as well as obligation to supply; vertical segregation of natural monopoly transmission system from competitive elements; corporatisation and privatisation of distribution and retail; establishment of a wholesale electricity market (which became fully operational in October 1996); and establishment of a "light-handed" regulatory regime to control the natural monopolies.

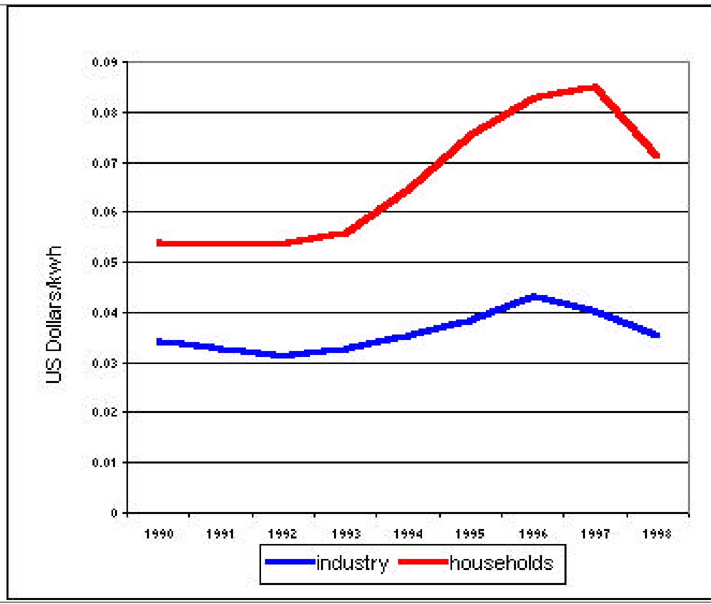
The Electricity Industry Reform Act 1998 instituted two significant further changes: (1) Local electricity companies were required to separate their distribution from retailing and generation activities into different companies by 2004; and (2) ECNZ was split into three competing State Owned Enterprises to increase competition in generation.

In addition, the Act required the industry to introduce a low cost system for changing electricity supplier. Arrangements (called profiling) were put in place on 1 April 1999 to ensure that small consumers can enjoy the benefits of competition.

The New Zealand Electricity Market Company is a privately owned, voluntary market. There is no government legislation relating to the governance or operation of the market. Electricity can be traded outside the wholesale market, hence maintaining competitive pressure. Market services, from dispatch to clearing and settlement, are provided on the basis of competitive contracts. NZEM operates 24 hours a day, seven days a week, involving both generators and retailers in the selling of around 85 per cent of the total electricity produced in New Zealand. The energy is traded plus losses at the grid exit point or node (there are around 240 nodes on the national grid). Prices are calculated on a half-hour basis.

Over the decade or so since the beginning of the reform process, the price paid by domestic consumers for electricity has risen steadily in real terms (a 25 per cent increase from 1987 to 1998). Rather than representing a failure of the reform process to achieve its basic objective, this represents the rebalancing necessary as historical cross subsidies were eliminated (the commercial sector, which had historically subsidised the residential sector, saw prices drop by 39 per cent over this period). The overall national average price of electricity over the period of the reforms has remained relatively constant, at an average of around 9.5c/kWh (real at March Year 1998 prices). Figure 32 shows the end-user prices for household and industry sectors.

Figure 32 Electricity Price for Household and Industry in New Zealand



Source: IEA Statistics, Second Quarter 1999

PHILIPPINES

The government has the objective to see more competitive energy market, pursuing the privatisation plans in oil and electricity sector in the future.

PETROLEUM PRODUCTS

The country is the oil importer with production capacity of only less than 15 per cent of its total consumption. The country's oil demand is expected to increase slightly over the next several years because of the slow economic growth. However, fuel oil is the only fuel which will be diminished from market because government's drive to getting rid of retired oil-fired power plants.

There are crude oil production in the country by foreign exploration company in the northwest of Palawan Island and small concessions areas in Philippines. The survey shows the possible significant quantities of oil may be recovered from this exploration.

The largest refinery of the country is Petron Corporation, with government holding and Saudi Aramco, with capacity of 180 kbd, and Shell's of 137 kbd, and Caltex of 72 kbd.

The downstream oil sector is in the process of deregulation. The Philippines Congress passed a new bill to deregulate the oil industry in 1998. The Downstream Oil Industry Act of 1998 liberalised and introduced competition into oil industry. This includes the uniformity of 3 per cent tariff duty on imported crude oil and petroleum products. The Act also allowed the barrier to newcomer to the market by eliminating a requirement of all downstream operations to maintain a 40-day inventory. These newcomers are Coastal Petroleum and Total major imported oil products. Beginning in March 1998 oil prices are deregulated and set by the oil companies except for socially sensitive products such as regular gasoline and kerosene. However, deregulation in Philippines did not go smoothly as anticipated, price hikes announcement in response to rise in crude import prices, caused government initiation in investigation for reasonable prices increase in the market..

NATURAL GAS

The government has expanded the gas use particularly in power generation to reduce reliance and cost on oil import. The new gas field, Malampaya-Camago was discovered in 1989, which Shell holds the concession and is constructing the pipeline to three power plants with a total capacity of 2,700MW. Another filed with is under exploratory drilling is Nido concession under 20-year sale contracts by Shell.

ELECTRICITY

Two key players in power sector are National Power Corporation (NAPOCOR) and Manila Electric Company (MERALCO). MERALCO supplies the Manila and Metropolitan areas, while NAPOCOR supplies the rest of the country. Though, currently, NAPOCOR and MERALCO are state-owned, the government plans to privatise in the future. The government plan is to develop a competitive market by selling its stake in MERALCO and dividing NAPOCOR into separate regional entities. The privatisation program has drawn the interest by many U.S. companies. However, the settlement will not be a short process since Legislation of Privaisation of NAPOCOR is under the consideration by the Philippine Congress.

The country's total generating capacity is 11.6GW, which is an oversupply by 3.2GW. The government has plans to reduce oil imports by shutting down seven retired oil-fired plants with a total capacity of 1,677MW by the end of 1999. Instead, the government is replacing country's demand with three new gas-fired power plants, with 2,220MW capacities in 2002, and additional 500MW in 2003. These new gas-fired power plants will link to gas pipeline from Malampaya gas field.

The government has initiated to make electricity pricing more transparent to the public by the unbundling of the electricity industry as mandated by Executive Order No. 473, which was signed by former President Fidel V. Ramos on April 17, 1998.

RUSSIA

Russia is a major energy producer, and significant exporter of energy. Russia has the world's largest natural gas reserves, second largest coal reserves, and eighth largest oil reserves, although the majority of these reserves are located in remote areas of Siberia. Russia is also the world's second largest energy consumer, world's largest exporter of natural gas and second largest exporter of energy and petroleum in the world.

The Russian energy sector is a cornerstone of the domestic economy, providing needed export earnings, and foreign direct investment flows. The economic importance of the energy sector has gradually increased since the 1970s and particularly during the transitional recession of the 1990s. Russian energy policies range from state subsidies for coal mining, through to revenue generating tax revenue for the highly profitable gas industry.

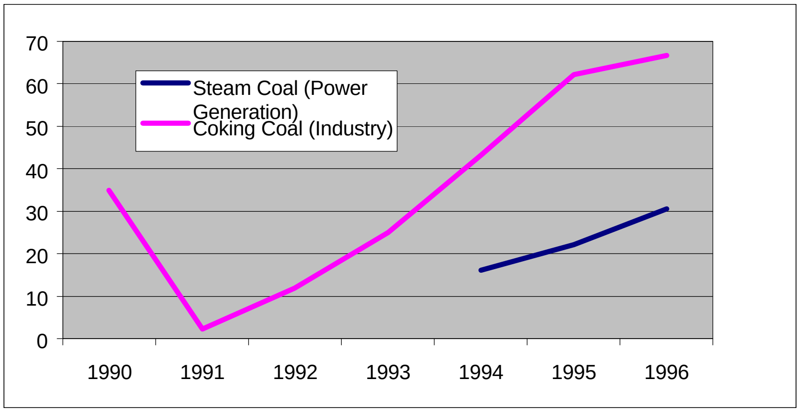
COAL

Traditionally coal has been an important part of the Russian energy sector. Russian coal production declined 269 million tonnes in 1997, continuing the decline that has been evident throughout the 1990s. This decline can be partially attributed to industrial problems resulting from shortages of liquidity. The failure by coal consumers, particularly electricity power generators, to pay approximately 80 per cent of their accounts has been a central cause for liquidity shortages among coal producers. As liquidity tighten, coal producers defaulted on their wage payments and subsequently became the target of industrial action by their workers. To some extent the Russian government has stepped in by partially compensating coal producers through government subsidies, however this compensation has only been directed towards producers who are believed to be economically viable over the long term.

Restructuring initiatives have been implemented by the Russian government which aim to privatise economically viable mines and close uneconomic mines. The government has also declared that savings from the closure of unprofitable mines will be directed into profitable mines, and used for upgrade facilities prior to privatisation. The government is also looking to remove subsidies across the sector.

The liberalisation of domestic coal prices began in 1993. According to the (International Coal Report, 466, 25 January 1999) coal subsidies have declined from over US$2 billion in 1994 to less than US$0.5 billion in 1998. A significant part of this reduction can be attributed to the closure of unprofitable mines.

Figure 33 Russian Coal Price Trend
US$/ton

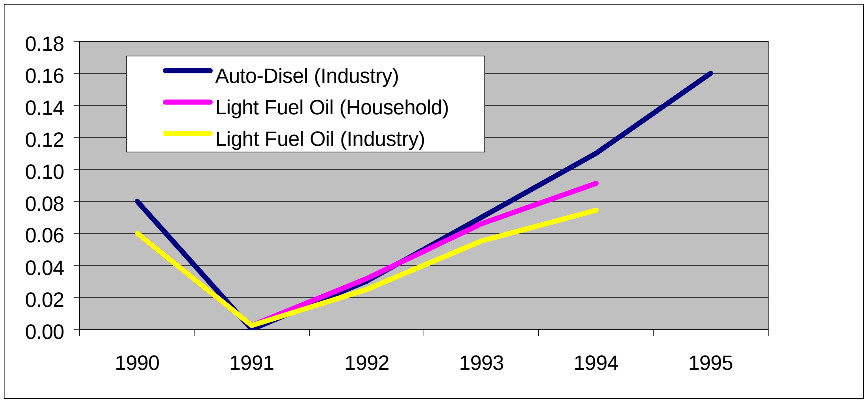


Source: APERC Energy Database

PETROLEUM PRODUCTS

After a reorganisation and privatisation process began in 1993, the Russian oil sector now is divided between vertically integrated companies and a small number of regional independent producers. Restrictions on foreign ownership of privatised companies have been removed through a presidential decree that abolished the 1992 decree limiting foreign ownership to 15 per cent. Russia's State Property Committee approved a plan to privatise Rosneft, the country's largest oil company still in state hands. However, Russia has twice had to postpone its planned US$1.6 billion sale of Rosneft because of a lack of bidders.

Figure 34 Petroleum Product Price Trend in Russia
US$/litre



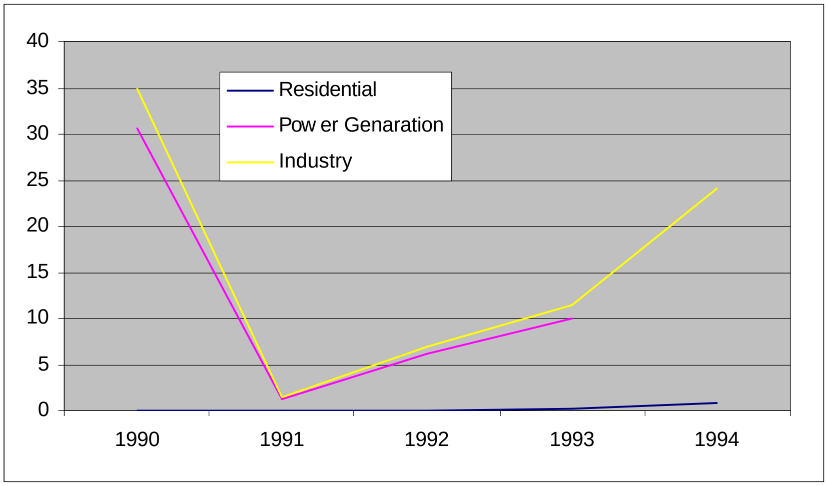
Source: APERC Energy Database

NATURAL GAS

Though Gazprom has dominated Russia's natural gas industry, its 1997 revenues of $23 billion made it Russia's largest earner of hard currency, while its existing tax payments accounted for 25 per cent of federal government tax revenues. Gazprom has been unable to make all of its tax payments because only about 15 per cent of its domestic customers pay promptly and in cash, and also Gazprom has been prevented by the government from shutting off supplies for non-payment to power generation and other industries.

Russia's natural gas pricing structure has been changed in order to bring in more cash payments to Gazprom. In February 1998, Russia's Federal Energy Commission proposed that the differential in the price of gas to household and industry be eliminated because households were paying less than the cost of producing gas. In addition, Presidential decree 890 was passed, allowing discounts in the price of gas for customers paying in advance with cash.

Figure 35 Natural Gas Price Trend in Russia
US$/million kcal



Source: APERC Energy Database

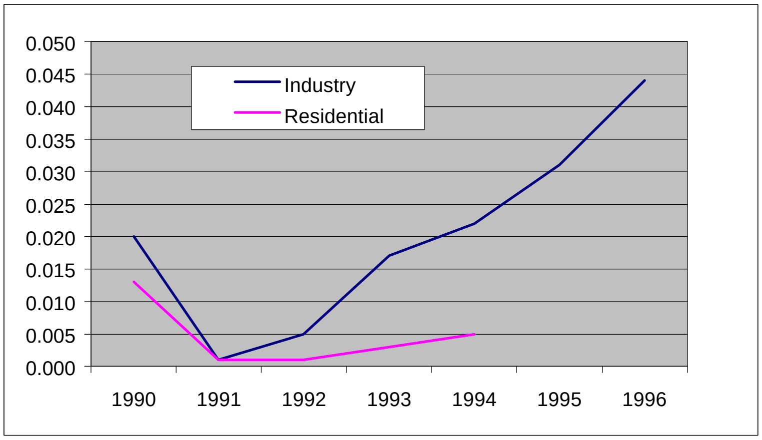
ELECTRICITY

Russia's power sector, which is 52.7 per cent state-owned by the RAO UESR (United Energy Systems of Russia), has been targeted for restructuring. This action was precipitated by a Presidential Decree in April 1997 "On Reforming the Natural Monopolies" which would allow electricity consumers to buy power directly from the generators. However, it is unclear whether the proponents of these reforms can maintain the political drive to deliver them.

The Presidential Decree has been largely ignored by regional power companies, which continued to prevent individual power plants selling cheaper power to consumers. The power industry has also resisted the closing inefficient power plants and reducing the workforce.

The government plans to introduce competition among power-generating enterprises through a new system of payments for electricity from national grid. Currently, Russian wholesale electricity prices are low, about US$0.03 per kWh. Russia's Federal Energy Commission has announced plans to bring household electricity prices to within 80 per cent of industrial prices, as household tariffs currently are much lower than the cost of generating electricity.

Figure 36 Electricity Price Trend in Russia
US$/kWh



Source: APERC Energy Database

SINGAPORE

Throughout 1990s Singapore has done restructuring in the electricity generation and supply. Beginning in 1999, the structure of electricity prices has been modified to reflect the cost of transmission and distribution. This change was introduced in line with the unbundling of the transmission and distribution charges.

CHINESE TAIPEI

Chinese Taipei is endowed with limited energy resources, and imports the majority of its primary energy supply. Currently the energy supply industries are mainly state-owned and prices are generally controlled, however the energy sector is gradually being deregulated with some petroleum product prices determined in the free market.

Traditionally, one of the fundamental aims of the Chinese Taipei's energy policies was to ensure that the energy sector provided low cost energy to help facilitate sustained economic development and growth. However during the 1990s, government policy has signalled that energy prices should reflect actual costs plus an appropriate rate of return, and take account of other factors, such as energy conservation and environmental sustainability. More recently, some energy markets, mainly for petroleum products, have been deregulated subject to some price caps.

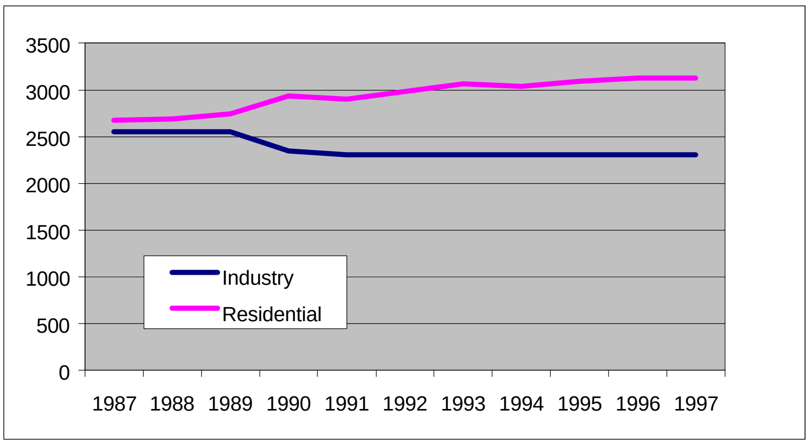
A 5 per cent VAT currently applies across all energy products, and a 0.5 per cent harbour construction fee also applies across all imported energy commodities.

COAL

Nearly all Chinese Taipei's coal requirement, of around 30 million tonnes a year, is imported. The price for imported coal is determined either through negotiation with coal exporters in other economies, or alternatively through international spot markets. As a result of the high import dependence, domestic coal prices tend to reflect international trends. Coal imports are free of import tariffs and excise taxes, however steam coal is subject to an air pollution fee of NT$170 per tonne (approximately US$6.23 per tonne) was imposed in 1995.

The government continues to maintain a ceiling price on domestically produced coal for social reasons, however as domestic production is less than 1 per cent of domestic supply this effect is not significant.

Figure 37 Coal Price Trend in Chinese Taipei
NT$/ton



Source: APERC Energy Database

PETROLEUM PRODUCTS

Like coal, Chinese Taipei is nearly completely dependent on imports of crude oil and other petroleum products. The oil sector has been increasingly deregulated and currently prices for some selected petroleum products are determined through the free market without government intervention.

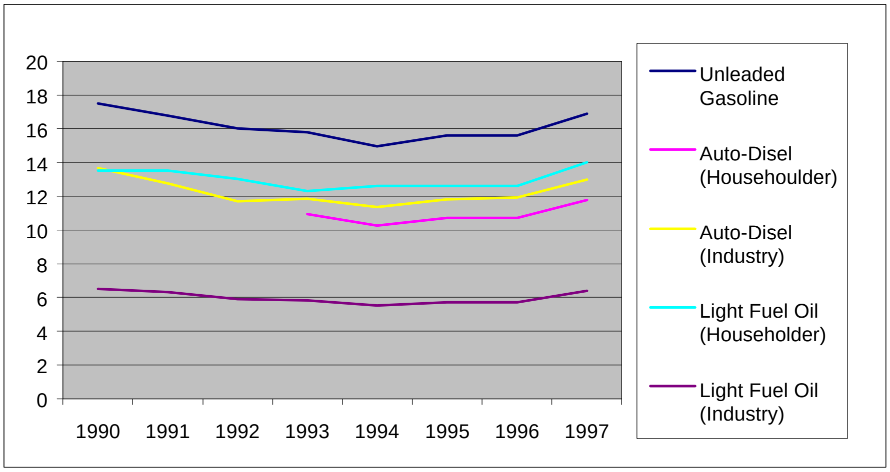
Oil imports into Chinese Taipei are purchased on international oil markets, and reflect conditions in those markets.

The oil product pricing formula, which was adopted by Executive Yuan in early 1993, was discontinued in March 1998 in favour of a system of floating oil prices. Like the formula pricing mechanism, which linked monthly changes in the domestic oil price to changes in an index of international crude oil prices and also CPC's accumulated earnings, floated oil prices are still controlled by the government, but CPC is authorised to adjust oil prices on a weekly basis (and within a prescribed range) according to international pricing trends. The domestic price maintained by the government reflects the costs of supply plus a reasonable rate of return and also other policy objectives.

Although it is a closely controlled float, this system provides greater synchronisation between domestic and international oil pricing trends.

In early 1999 selected oil products; such as LPG, jet fuel and fuel oil; were deregulated and the pricing of these products is determined freely through the domestic market. It is anticipated that this system will be applied throughout the oil market during 2000.

Figure 38 Petroleum Products Price Trend in Chinese Taipei
NT$/litre



Source: APERC Energy Database

NATURAL GAS

Chinese Taipei domestically produces about 20 per cent of its gas requirement, importing the remainder from overseas gas markets primarily as LNG.

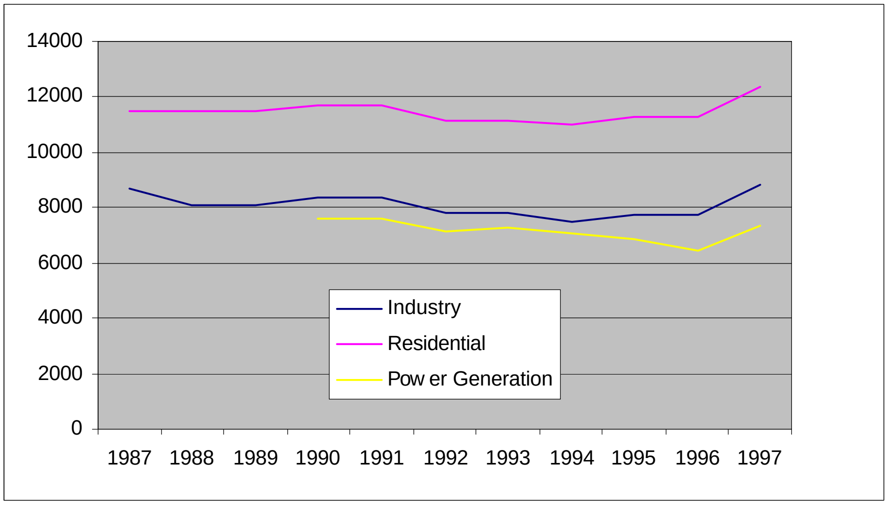
The Taipei government maintains controls domestic wholesale and retail gas prices. Domestic wholesale gas prices are determined by a 'cost plus' pricing formula, which was approved by the Executive Yuan in 1998. According to this formula, gas prices are reviewed on a monthly basis and the gas price reflects operational needs of the gas utilities, including a return on investment, as well as other social and environmental prerogatives. The formula also provides pricing discount of 15 and 9 per cent for power generation and some cogeneration plants. Large private sector consumers are permitted to negotiate prices directly with gas utilities (IEA, 1996).

According to the IEA (1996), a discrepancy exists between the rate of return permitted for gas utilities, 6 per cent, in comparison to the rate permitted for the power generation sector which ranges between 9.5 and 12 per cent.

The Ministry of Economic Affairs determines retail gas prices according to Gas Utility Regulations. The retail price considers the operational needs of the gas utilities and consumer welfare, including social equity (Energy Commission, 1998). In addition, utilities have some recourse of appeal to the Ministry for a price review if they can show they cannot operate with a 6 per cent return at the established price.

Gas imports into Chinese Taipei are subject to a customs tax of 4 per cent and a NT$0.055 per cubic meter (effective 1 May, 1999) excise tax. In addition, CPC's (Chinese Petroleum Company) monopoly ownership of existing LNG receiving, storage and transportation facilities arguably creates a further barrier. The Taipei government maintains a policy of encouraging diversified gas import sources, in the form of long-term supply contracts as opposed to purchasing LNG on existing spot markets.

Figure 39 Natural Gas Price Trend in Chinese Taipei
NT$/million kcal



Source: APERC Energy Database

ELECTRICITY

Electricity prices are also controlled by the government and, in general, based on the costs of generation plus reasonable rate of return on investment. The government also uses electricity pricing as a policy tool to encourage energy conservation and assist social equity. The reasonable rate of return, which is approved by legislature, ranges from 9.5 per cent to 12 per cent for power generators.

Electricity prices are applied to various categories, including low, high and extra high voltage for both industrial and commercial consumers. The price in each category varies according to time of consumption, and also seasonality. Electricity consumption in summer is higher than winter, and is approaching supply capacity. Therefore separate summer peak pricing was introduced, at significant premiums, to flatten peak consumption. A summary of pricing schedules for the state owned Taiwan Power Company are shown in Table 31.

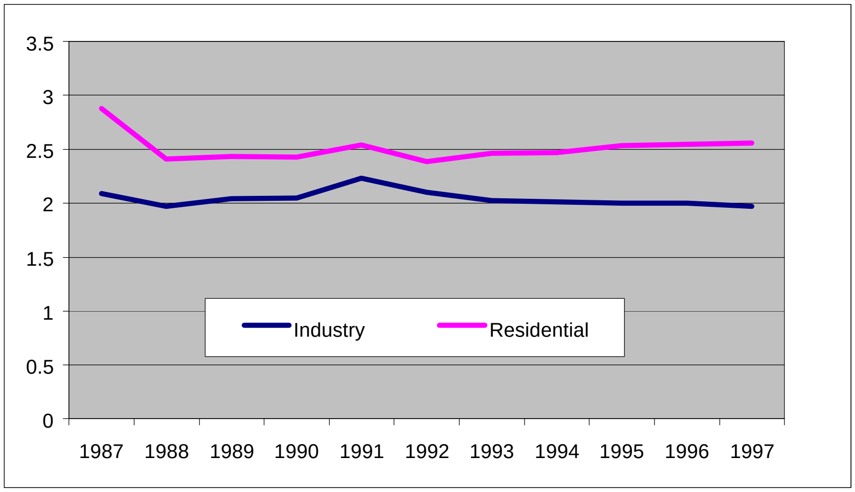
Table 31 Chinese Taipei Electricity Prices

			High Voltage Industry		Extra High Voltage Electricity	
			Summer	Winter	Summer	Winter
Fixed Charge	Normal	kW	213	159	207	153
	Semi-Peak	kW	159	159	153	153
	Off-Peak	kW	42.6	31.8	41.4	30.6
Variable Changes	Normal	kWh	3.06-5.36		3.04-5.32	
	Semi-Peak	kWh	1.84	1.78	1.83	1.77
	Off-Peak	kWh	0.7	0.65	0.69	0.64

Source: Taiwan Power Company, 1999

In the residential sector, electricity prices vary according to time of use, and prices are also seasonally adjusted with significantly higher summer prices. The summer premiums, aimed at curtailing peak demand, were introduced in 1987 to cope with system capacity shortages and reduce the impact of outages and supply limits on subscribers.

Figure 40 Electricity Price Trend in Chinese Taipei
NT$/kWh



Source: APERC Energy Database

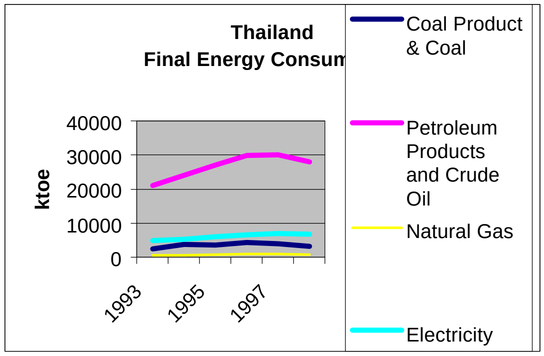
THAILAND

Over the past decade, Thailand has experienced rapid economic development and strong growth in energy consumption. The subdued economic conditions resulting from Asian financial crisis lowered energy demand and also affected the financial performance of the energy sector. In 1998, primary energy and power demand declined by 7.4 and 2.7 per cent, respectively. Domestic energy prices, often contracted in foreign currencies, increased as the Baht devalued. Following the financial crisis and with encouragement from the International Monetary Fund (IMF), the government has acted to prevent further loss to the industry. Action plans currently being pursued include:

- Reduction investment on supply side;
- Rationalisation of energy pricing policy;
- Acceleration of privatisation and deregulation initiatives, including the privatisation of the state oil and gas company, Petroleum Authority of Thailand (PTT), under the new Corporatisation Act;
- Renegotiation of energy contracts.

The trend in Thailand's final energy consumption is shown in Figure 41.

Figure 41 Final Energy Consumption of Thailand
1993-1998



Source: APEC Energy Database

COAL

Thailand is a net importer of coal, mainly for electricity generation, and domestic prices for coal reflect the prevailing world price. Coal consumption is expected to increase especially in manufacturing and power generation industry.

PETROLEUM PRODUCTS

Thailand's total petroleum demand is imported and more than 70 per cent of its crude oil imports from the Middle East. The economy has five oil refineries, with combined capacity of 704kbd. Economic difficulties have a significant impact on refining sector. Refineries have been running at capacity throughout the crisis despite falling domestic demand of oil products. In 1996, the refineries exported surplus production in an attempt to minimise losses. In response to falling margins and profits, refiners have been attempting to reduce operating costs. In 1997, the government reduced required stocks to help ease liquidity problems, and foreign exchange and storage cost saving. Refiners also can reduce reserves of products and crude oil stock surplus.

Deregulation of the oil pricing mechanism was initiated following the gulf crisis in 1991 in period of falling world oil price. Prior to deregulation, prices were based on Singapore postings and international spot prices. At that time, the domestic prices structure was derived from imported or ex-refinery prices, as well as an oil fund levy and various taxes. Following deregulation, the government abolished the determination of prices and allowed price setting by refiners. In addition, the government imposed an import levy and adjusted oil reserve regulations to protect domestic refiners. A comparison of oil product taxes prior to, and post, deregulation is provided in Table 32.

Table 32 Thai Import Taxes and Oil Reserve Adjustments Following Deregulation

	Prior to Deregulation	Post Deregulation
Import Taxes (Satang/litre)		
Gasoline, Diesel, Kerosene	1.0	6.5
Fuel Oil	0.1	1.0
Oil Reserves (% of volume)		
Crude held by refineries	4	5
Petroleum products held by oil traders	3	5
Imports petroleum products held by oil traders	3	5

Source: NEPO, 1996.

NATURAL GAS

The use of natural gas in Thailand grew 10 per cent a year between 1994 and 1998, following the implementation of government policies aimed at reducing dependency on imported energy and promoting the use of environmentally clean fuel. In Thailand, 80 per cent of gas demand is used in power sector, and 20 per cent in manufacturing. Future measures to promote gas utilisation in transportation sector are currently being considered.

Under the Thai Petroleum Act of 1973, the government owns all oil and gas resources and it can award concessions and other rights for exploration and production to qualified bidders that seek to invest in oil and gas exploration. If commercial quantities of natural gas are discovered, the concessionaire will negotiate a long-term or life-of-field contract to sell the gas to Petroleum Authority of Thailand (PTT).

According to the Petroleum Act, domestic prices for natural gas must be agreed between the concessionaire and the Petroleum Committee, and subsequently approved by National Energy Policy Office (NEPO). Gas prices are initially negotiated between the PTT and producers, and the PTT then negotiates sales to Electricity Generating Authority of Thailand (EGAT) at the producer price plus the cost of transmission and VAT. This price was around US$2.80 per MMBtu in 1993. In mid of 1992, wellhead gas prices for the Gulf of Thailand were reported to be around US$2.15 per MMBtu (IEA, 1996). The border price for natural gas imported from Myanmar is expected to be between US$2.50 and US$3.00 per MMBtu. Other than taxation of gas production, the government also applies a VAT at the rate of 7 per cent on retail sales of gas.

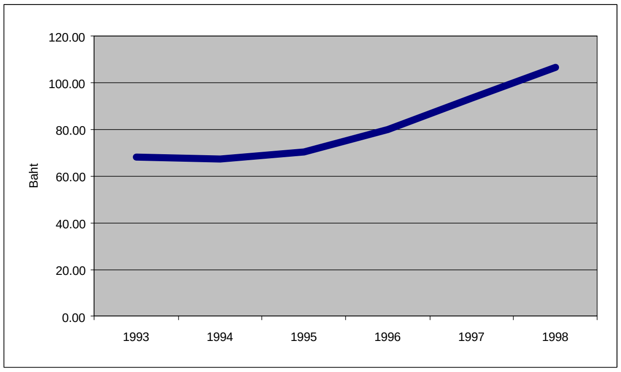
PTT was assigned by the Thai government to accelerate the procurement of natural gas both from concessionary resources in the Gulf of Thailand and from foreign resources. Thus, gas production has grown from 50 per cent by 1993, and 81 per cent within 1997. Thailand imported gas from Myanmar's Yadana gas field in November 1998 to supply to Ratchaburi power plants and will increase in the year of 2000 and negotiate for more gas from Yetagun filed. PTT meanwhile reached an agreement with PETRONAS on 50:50 gas purchase agreement from Joint Development Area.

Electricity Generating Authority of Thailand (EGAT), the country's electricity company, has planned to expand and enhance its cogeneration plants for more production efficiency. Independent Power Producers (IPPs) and Small Power Producers (SPPs) are promoted to utilise natural gas in power generation activities.

The Thai cabinet has approved plans to increase pipeline infrastructure, and deregulate the natural gas supply industry in Thailand. Deregulation will take place through three phases. Firstly, pipelines will be separated into major transmission and local distribution networks. Secondly, third-party access (TPA) will be promoted to help facilitate competition in the gas supply industry. Thirdly, the regulatory structure will be simplified with the aim of creating an independent regulator to oversee the industry.

Figure 42 shows the development of natural gas price in Thailand from 1993 to 1998.

Figure 42 Natural Gas Consumer Price in Thailand
1993-1998



Source: NEPO

ELECTRICITY

Thailand has around 17,500MW of electric generation capacity and generated 82 billion kWh of electricity in 1996. The recent decline in the Thai economy decreased domestic demand for electricity, and the government has acted to privatise and deregulate the electricity industry as a means to restore a market balance, improve transparency and promote efficient energy pricing. The Thai government is also revising the 'Electricity Act', and is in the process of establishing an independent energy regulator. Early indications are that the new structure is working well, although further fine-tuning may take place.

Privatisation initiatives for the electricity industry were first announced in September 1998, and have been progressing rapidly. During 1998, EGAT sold its share in the Electricity Generating Public Company (EGCO) to China Light Power, and PTT decreased its holding in Petroleum Authority of Thailand Exploration and Production (PTTEP) from 71 to 61 per cent. It is anticipated that electricity generation will be separated from transmission by 2003 and more government assets will be privatised, such as the Ratchaburi power plant in 2000.

The National Energy Policy Council (NEPC), via the Committee of Energy Policy, is responsible for the electricity price. The basic principles for electricity pricing are to ensure adequate net revenue for the efficient operation of utilities, reduce the system peak load, provide for future expansion, maintain system reliability, and promote efficient use of electricity. The existing retail pricing structure in Thailand is consistent with these objectives, and is based on long-run marginal cost (LRMC) of power supply at different voltage levels. The government permits slight variation in the pricing structure to allow for social equity and development considerations. In practice there are two forms of cross subsidisation:

- URBAN CONSUMERS SUBSIDISATION OF RURAL CONSUMERS occurs because the Metropolitan Electricity Authority (MEA) consumers are required to pay electricity prices that exceed the cost of service, and therefore subsidise Provincial Electricity Authority (PEA) consumers;

- RESIDENTIAL CONSUMER SUBSIDISATION, where consumption is less than 150 kWh per month, takes place for poor consumers who are only required to pay a lifeline price.

Apart from these variations, a uniform price (bulk supply tariff) is applied in Thailand based on the time of use. There are two time-of-use, peak (09:00-22:00) and off-peak (22:00-09:00), except for Sunday which is all off-peak. The bulk supply tariff (BST) for EGAT sales to the MEA and PEA are based on two financial criteria:

- Rate of return on assets of 8 per cent; and,

- Self-financing ratio of 25 per cent.

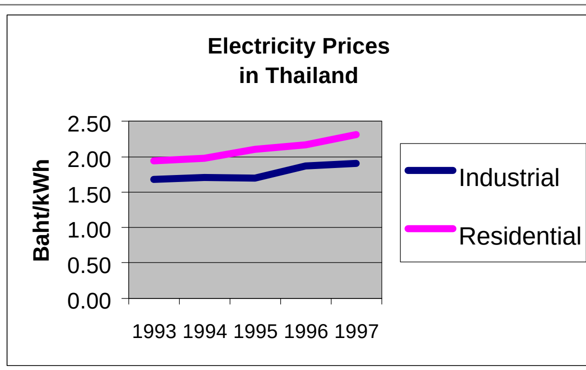
Base electricity prices (BST) from EGAT to the MEA and PEA areas have not changed since January 1997. However a current surcharge of around 0.25 Baht/kWh for MEA, and 0.12 Baht/kWh for PEA was imposed as well as a 10 per cent VAT.

In circumstances where changes in fuel prices are sufficient to warrant a change in wholesale and retail prices, an automatic price adjustment mechanism allows changes in fuel costs and other related costs to be incorporated into the price without government approval. This scheme was utilised between 1997 and 1998, where in response to more expensive fuel cost (resulting from the Baht devaluation) three upward adjustments were made in the retail price, totalling 15 per cent, to maintain the financial position of utilities.

Since deregulation of the power sector and the natural gas supply industry in Thailand has not advanced to the stage where the market is competitive. During the current transitionary period, the government has continued to progress restructuring initiatives to provide a smooth transition towards the competitive market by 2003.

Electricity price for residential and industrial consumers is illustrated in Figure 43 below.

Figure 43 Electricity Prices in Thailand
1993-1997



Source: NEPO

UNITED STATES

The United States is the world's largest consumer of energy, and both an importer and exporter of energy and relies entirely on the operation of free markets for the determination of energy prices. While all energy prices are determined by the prevailing supply and demand conditions, final retail prices may include federal, state and local taxes, which vary across the United States. Prices variations between states also occur, however arbitrage limits these variations to specific factors influencing the particular market.

COAL

Coal made up 32 per cent of total energy production in 1996. The U.S. has recoverable coal reserves more than anywhere in the world, being a leading coal producer. 10 per cent of the coal extraction goes to exports and 90 per cent goes to power generation.

The United States produced 1,105 million short tonnes (mmst) of coal in 1999, following record production in 1998 of 1,118.1 mmst. Of this total, the United States will consume 1,049 mmst and export (net) 53 mmst. For the country as a whole in 1997, 60 per cent of coal produced was bituminous, 32 per cent sub-bituminous, and 8 per cent lignite (brown coal). Electric utilities account for the vast majority (around 90 per cent) of U.S. coal consumption, with independent power producers (IPPs) and manufacturing consuming the remainder. This pattern is expected to continue through 2020 at least, with coal maintaining a fuel cost advantage over oil and natural gas.

Coal faces no controls that affect either prices or quantities. However, technical, environmental and safety regulations imposed on the mines and electricity generation have impacts on coal industry. Two major regulations in the power industry profoundly impact coal prices; the 1990 Clean Air Act and emerging competition in the electricity supply industry. The Act imposed limits on sulphur dioxide emission for coal-fired plants. As a result, this led to a shift towards low-sulphur coal, and, therefore, the use of high-sulphur coal declined by 26 per cent during 1990 to 1995 (The role of EIA governments in Energy, IEA 1996).

During 1990s, electricity deregulation affected the coal prices. Electric utilities and other power producers came under pressure to shed high-cost, long-term coal supply contracts and enter into more flexible, risk-sharing supply agreements. The downward trend in coal prices favoured highly productive coal suppliers. Successful coal producers and their customers now benefit in one or more ways from economies of scale. In terms of physical scale, benefits derive from huge Western surface mines; big, efficient long-walls; large, automated loadouts and lower rail rates for major shippers; and efficient unit trains made up of larger, higher-capacity coal cars. On the fiscal side, the grand scale of financing or self-capitalisation options at coal production operations backed by large corporations or investing partnerships permits risk-averse customers to seek optimal coal prices and quality without potentially costly long-term contract commitments (EIA Website).

Table 33 Average Annual Price of U.S. Coal Receipts by End-Use Sector
1993-1999; US$/short tonne

	Electric Utilities	Coke Plants	Other Industrial
1993	25.58	47.44	32.23
1994	28.03	46.56	32.55
1995	27.01	47.34	32.42
1996	26.45	47.33	32.32
1997	26.16	47.61	32.41
1998	25.64	46.06	32.26
1999	25.14	46.37	31.58

Source: EIA Website

PETROLEUM PRODUCT

The downstream industry has developed merging among independent refiners and integrated companies, driven by low U.S. downstream profitability and the resulting need to cut costs to maintain shareholder value. The burden of tightening transportation fuel and environmental emission regulations increased for the downstream industry. Since early 1997 U.S. refineries have operated near capacity. With the U.S. as a net oil-product importer and with rising oil-product demand., net oil imports in 1997 rose to over 50 per cent of U.S. consumption and future demand growth must be met by increasing imports.

While petroleum product prices including gasoline, heating fuel, aviation fuel are determined in the free market, all petroleum products are subject to federal, state and some local taxes.

NATURAL GAS

In 1996, the gas industry delivered 504Mtoe to consumers, 440Mtoe of domestic production and 64Mtoe from Canadian imports. Gas consumption and production have risen steadily since the mid-1980s when the Industrial Fuel Use Act was lifted. Domestic gas production has risen by more than ten per cent over the last decade.

Natural gas is considered a desirable fuel in the United States for both environmental and national security reasons. A presidential statement in October 1997 called for a policy of fuel conversion, from coal powered electricity generation to gas fired power. The U.S. currently produces around 19Tcf of gas, which meets approximately 25 per cent of the U.S. energy requirement.

Under the Federal Energy Regulatory Commission (FERC) Order 660, natural gas prices had been deregulated since 1978 and currently the natural gas market is totally deregulated. Natural gas in the U.S. is used mostly for space heating with increasing use for power generation. However, price of natural gas includes some federal, state and lLocal taxes.

ELECTRICITY

The U.S. has very large electricity supply industry, which the current generation of 3,652 TWh, of which 9.6 per cent comes from hydro, 19.6 per cent from nuclear, 52.7 per cent from coal, 2.6 per cent from oil, 13.2 per cent from gas and 2.2 per cent from non-hydro renewables. Demand is shared among sectors as indicated in Figure 44.

Figure 44 Electricity Generation by Fuel Type in the U.S.

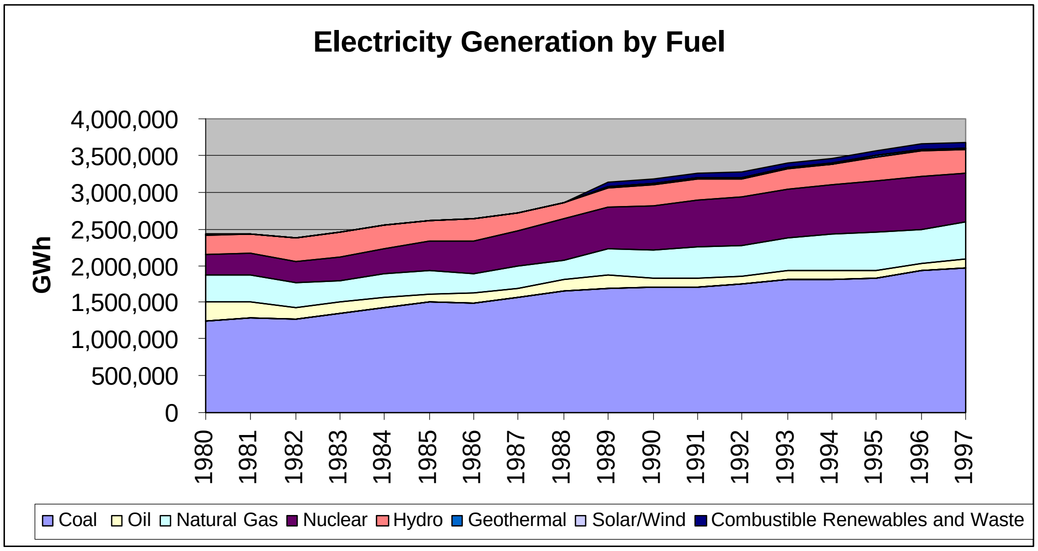
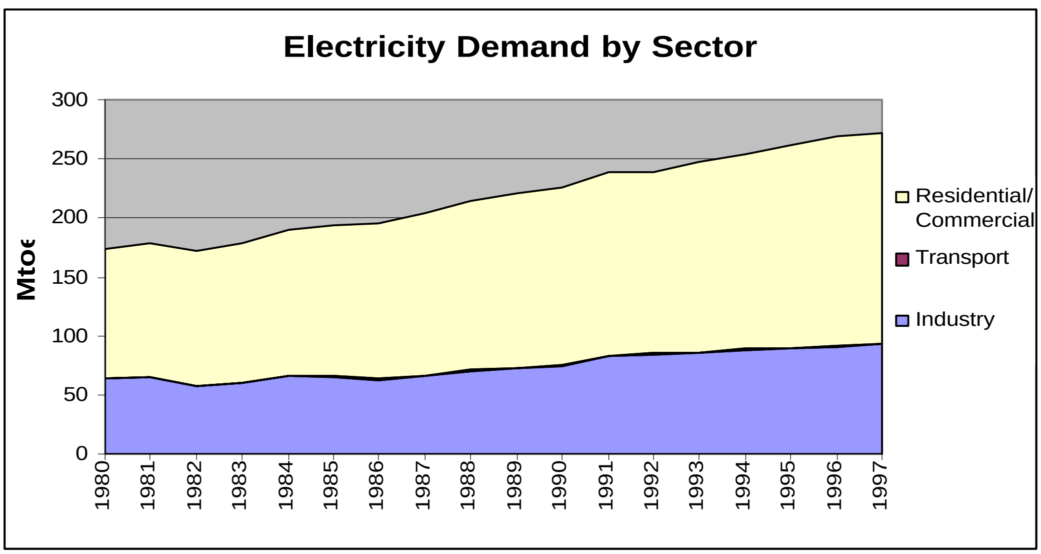


Figure 45 Electricity Demand by Sector in the U.S.



The U.S. electricity market has been gradually deregulated, but its prices vary considerably from state to state. Currently, electricity markets in many parts of the economy are being restructured to increase competition. Despite several proposals, no comprehensive federal electricity restructuring bill has been enacted although a number of states have taken regulatory and legislative actions of their own. Electricity price is subject to federal, state and local taxes.

Table 34 Average Electricity Price in the U.S.
1997 and 1998

	1997 US cents/kWh	1998 US cents/kWh
National average electricity price	6.85	6.75
Residential	8.43	8.27
Commercial	7.59	7.43
Industrial	4.53	4.50

Source: Energy Information Administration, DOE

VIET NAM

The Viet Nam government is aiming to reform energy pricing mechanisms as a means to facilitate an expansion of business activities and to promote more efficient energy use. One of these initiatives is to progressively raise average retail electricity price to a reasonable level by 2010.

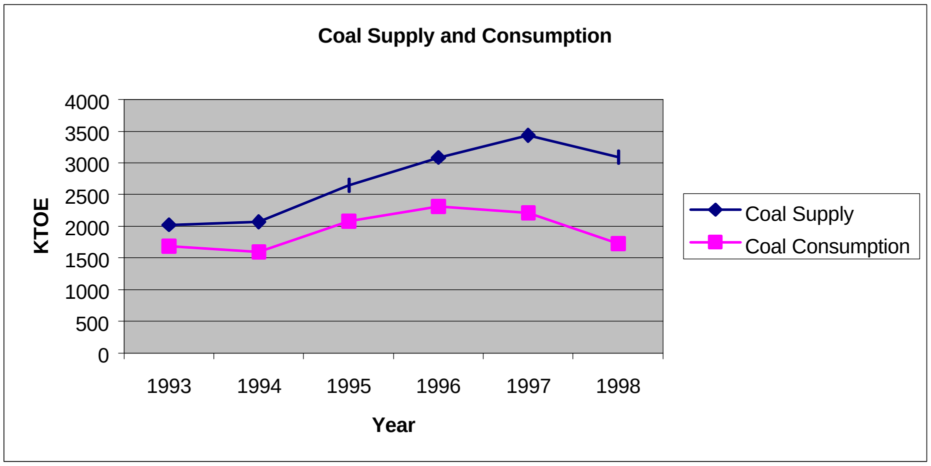
COAL

Viet Nam produced over 10 million tonnes of coal in the past two years and is expected to increase its production to 15 million tonnes by the year 2005. Coal is produced by Viet Nam National Coal Company (VINACOAL), which was established in 1995 by the Ministry of Industry (MOI). VINACOAL business includes the exploration, production, processing, and distribution. VINACOAL has various subsidiary companies: Campha, Hon gai, Uongbi, Coalimex Companies and others.

The shares of coal consumption be sector in 1997 were as follows: 32 per cent for export; 22 per cent for the power sector; 35 per cent for the industry sector, and 11 per cent for others.

Figure 46 shows a significant decreasing trend in coal supply and consumption from 1997 to 1998, caused by the Asian financial crisis that affected coal supply and consumption, especially exported coal to the foreign markets.

Figure 46 Coal Supply and Consumption in Viet Nam
1993-1998



Source: APEC Energy Database

The current price of coal is gradually approaching the market price except for the power sector, which is controlled by the government, and exported coal determined by international markets as shown in Table 35.

Table 35 Average Coal Price in Viet Nam
1997

Coal type	Consumer	Heat rate Kcal/kg	Price 1000VND/ton	Price US$/ton
Steam 4,5	Power	5000-5500	240-250	20.5-21.4
Steam 4,5	Export	5000-5500	FOB	22-23
Steam 3	Cement	5500-5600	300-350	25.6-30
Steam 6,7	Residence and others	< 5000	< 200	17
Anthracite	Export	7600-7800	FOB	55-60

Source: Institute of Energy, Internal Discussion Paper, 1999, Viet Nam; VINACOAL, Internal Discussion Paper, 1999.

After the implementation of reforming the energy sector from 1995, average coal prices increased from 200,000 VND/ton in 1995 to 231,000 VND/ton in 1997. However, prices for the domestic consumers have been still lower than production cost by about 15 per cent. Therefore, in fact, the export earnings have subsidised domestic consumers.

Table 36 Average Consumer Price and Producer Price in Viet Nam

Price/year	1995	1996	1997
Consumer price	200VND	220VND	231VND
	US$17.1	US$18.8	US$19.7
Producer price	243VND	263VND	270VND
	US$20.7	US$22.4	US$23.1

Note: Unit: 1000VND/ton and US$/ton
Source: VINACOAL, Internal Discussion Paper, 1999

In summary, domestic coal prices are partly determined by market forces, subject to the minimum sales prices set by the Coal Consumers Association. The State Pricing Committee (SPC) sets prices of coal for power generation.

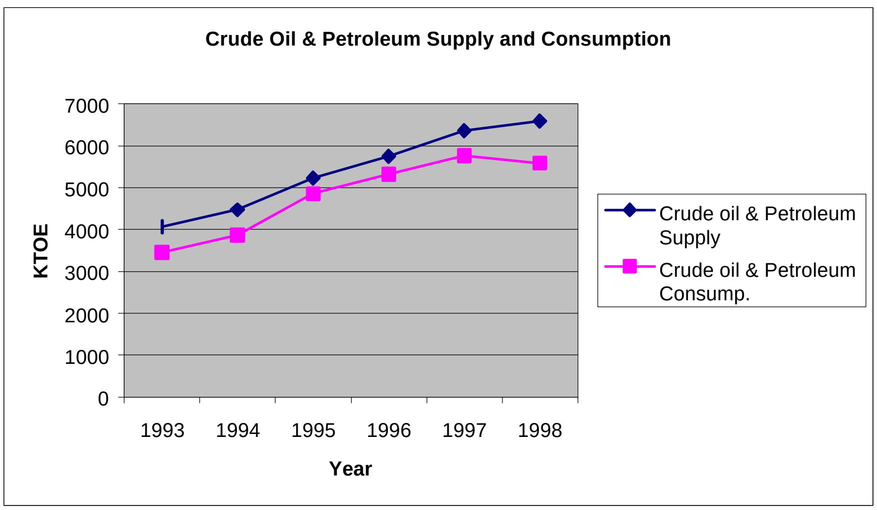
CRUDE OIL AND PETROLEUM PRODUCT

Viet Nam Oil and Gas Corperation (PetroVietnam) a state-owned enterprise was established in1975 and controlled by the Prime Minister's Office. They are responsible for crude oil and gas exploration, production, transportation, and research. PetroVietnam has three major units and one subsidiary company as follows:

- General Institutional Management Unit,
- Vietsopetro Joint Venture Unit (exploiting crude oil in White Tiger and Dragon fields),
- Multi Joint Venture Unit (from Petronas Karigali, Total, Sumitomo, and PetroVietnam) exploiting crude oil in Big Bear field, and
- PetroVietnam Gas Company (PVGC-operating White Tiger pipeline).

Figure 47shows that supply and consumption of crude oil and petroleum products grew by 11.9 per cent and 13.7 per cent respectively during the period of 1993-1997. And during 1997-1998 it decreased by 3.7 per cent for supply and 3.0 per cent for consumption.

Figure 47 Crude Oil and Petroleum Product Supply and Consumption in Viet Nam



Source: APEC Energy Database

Most of Viet Nam crude oil is exported to various economies around the world. In 1997, crude oil was exported to Japan (65 per cent), Singapore (15 per cent), and China (5 per cent) and to Korea, Australia and other economies (15 per cent).

The crude oil pricing is based on the international market price as shown in Table 37.

Table 37 Viet Nam and World Crude Oil Prices
US$/barrel

Crude oil type/year	1994	1995	1996	1997
White Tiger (Viet Nam)	16.79	18.19	20.99	20.25
Brent (U.K.)	15.82	16.92	20.30	19.45
WTI (U.S.)	17.19	18.32	21.70	20.76

Source: Institute of Energy, Internal Discussion Paper, 1999, Viet Nam; The World Bank, *Commodity Price Outlook 1998*

The Ministry of Trade and Tourist (MTT) is responsible for export of crude oil and import of petroleum products and distribution to consumers through Petrolimex and Petechim Companies. In addition, about seven more state-owned and joint venture enterprises involve in trading petroleum products. About 60-70 per cent of domestic consumption is covered by Petrolimex and Petechim Companies.

Although Viet Nam exported 11-12 million tons of crude oil in the past two recent years, it has imported petroleum products for almost domestic consumption (5.95 million tons in 1997).

State Price Committee (SPC) is responsible for setting prices. Assumption is based on the CIF cost, the exchange rate, distribution costs, taxes and others. Area characters such as rural and mountainous areas are also taken into account.

Table 38 on petroleum products prices shows that:

- The retail petroleum prices have been rather high compared to ASEAN countries like price of gasoline in Malaysia (0.3 US cent/litre).
- Road taxation on every used object has not been yet rational because it is not suitable to apply the road tax on power generation.
- The gap of this tax rate between gasoline and diesel is high, and it leads to an inefficient use of diesel.

Table 38 Petroleum Product Prices in Viet Nam

US$/ton

Petroleum products	Import price (CIF)**	Import tax* (%)	Road tax $/Ton	Other surcharges (%)	Consumer Price (VND/l)	Consumer Price*** ($/ton)
Gasoline (Mogas 83)	214.7	60	61	0	4200	489.5
Kerosene	203.7	45	0	0	3600	384.3
Diesel (1%S)	190.6	50	31	0	3500	347.7
Fuel oil (3.5%S)	107.8	12	0	0	2000	180.3
Jet oil	226.5	45	0	0	3630	340.9
LPG	232	30	0	0	7700VND/kg	658

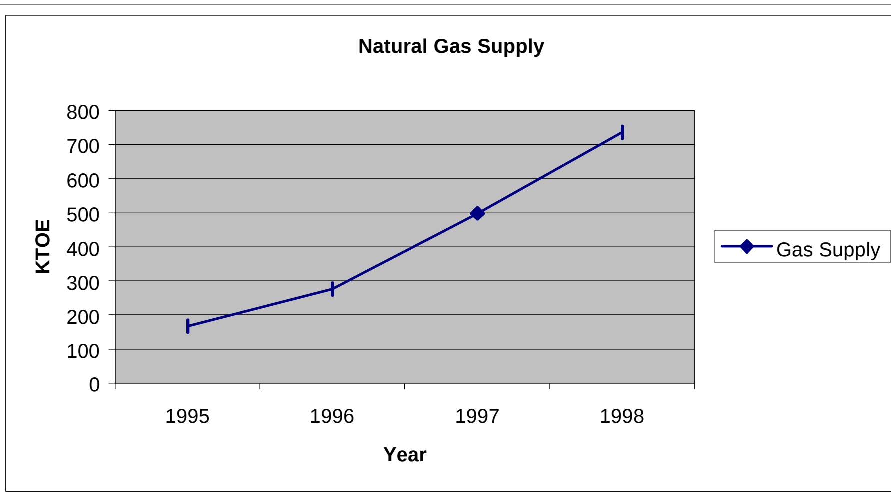
Note: * Import tax valued from 1 September 1997
** Import price is estimated.
*** Exchange rate 1US$=11,700VND

Source: Ha Noi Market, August 1997

NATURAL GAS

The gas industry has grown steadily since the discoveries of gas fields in the 1990s, the construction of the first 16-inch pipeline in 1993, and its utilisation in 1995. Associated gas from White Tiger field has been used as a fuel supply to Baria power plant since 1995, and the growth rate of natural gas supply was about 64 per cent over the period 1995-1998.

Figure 48 Natural Gas Supply in Viet Nam



Source: APEC Energy Database

Pricing natural gas is quite new to the country. At present, the government sets associated gas price, where it does not reflect real cost of production. However, Table 39 shows the gas price trend is increasing. In the near future, the natural gas price could be based on a negotiated initial price and indexed to the price of fuel oil and steam coal on the international market.

According to the recommendations of the World Bank, "the price level must balance supply costs and market value, benefit to private and public participants' interests of upstream and downstream government agencies, and short-term and long-term interests of Viet Nam and the private sector. Using gas to produce fertiliser is considered a less than optimal use of gas."

Table 39 Development of Associated Gas Price for Power Generation in Viet Nam
1995-1999

	Price US$ per Million BTU
1995-1996	1.15
1996-1997	1.75
1997-1998	1.87
1998-1999	2.00

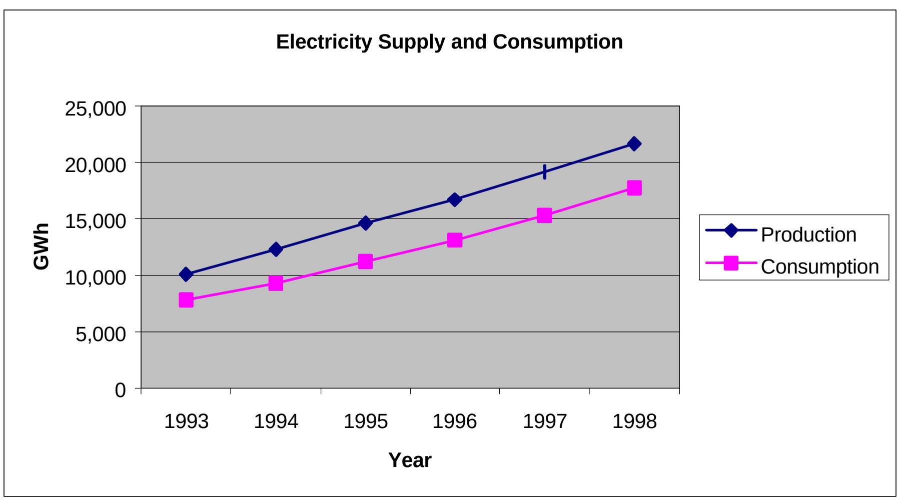
Source: PetroVietnam, Internal Discussion Paper; Institute of Energy, Internal Discussion Paper, 1999

ELECTRICITY

Electricity of Viet Nam (EVN) is one of the five largest state-owned enterprises, which is operated under Prime Minister's Office and Ministry of Industry. Since December 1998, EVN has increasingly expanded its electricity business, to meet electricity demand of the country, including seven distribution companies, four transmission companies, thirteen power plants and an energy research institute. EVN is also responsible for the country's energy planning through the Institute of Energy.

Electricity consumption and supply grew up rapidly along with economic development at rates of 18.2 per cent and 17.6 per cent, respectively, over the period 1993-1997. Although the trend of growth rate is slowing down after 1997 due to the Asian financial crisis, it is about 15.9 per cent for consumption and 13.1 per cent for production (see Figure 49).

Figure 49 Electricity Supply and Consumption in Viet Nam

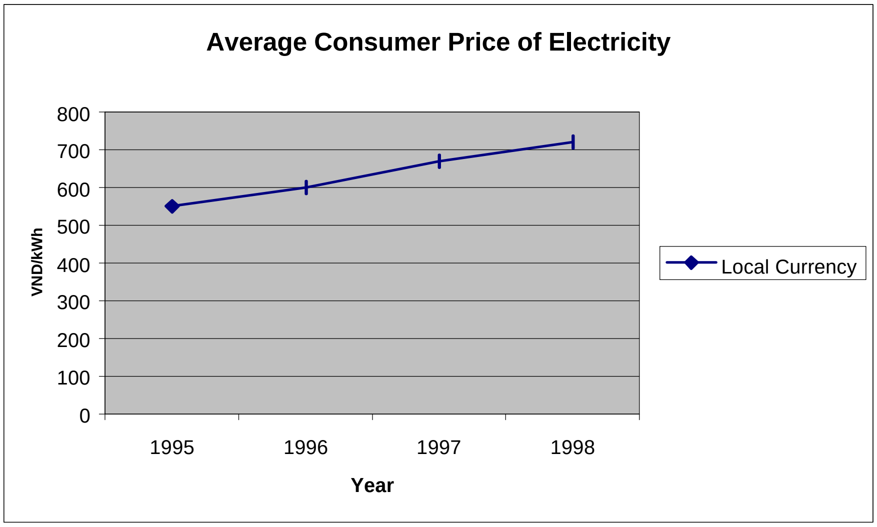


Source: Institute of Energy, Viet Nam, Research Project 09-03, 1999

The graph in Figure 50 shows level and trend of average retail electricity price during the period 1995-1998. However, the current price of electricity has not reflected yet the long run marginal cost, which is estimated at 980-1,100VND/kWh. Therefore, in order to approach the long-run marginal cost, the average electricity price has been adjusted by the government to 750VND/kWh starting from October 1999 (Viet Nam Government, 1999).

Electricity prices in each category are uniform across Viet Nam and controlled by the government. Price changes must be evaluated by SPC and approved by the National Assembly.

Figure 50 Average Consumer Price of Electricity in Viet Nam
VND/kWh



Since a uniform electricity tariff is applied to all similar classes of customers purchasing similar quantities of electricity, differences in the cost of bulk power supply and the distribution costs among seven distribution companies are not reflected in the tariff charged to customers.

It appears that the government subsidises certain customer classes. At the same time, the time-of-use periods (peak, off-peak, and regular periods) are also used in the current electricity tariff.

The government is rationalising regulation of electricity pricing, and also looking for the improvement in the following areas.

- Retail tariff structure should reflect seasonal factors; particularly the country relies on hydropower sources of supply.
- The average retail price should be raised to the long run marginal cost.
- The metering and billing capabilities as well as their regulation should be considered together with changing tariff.

With the current structure, EVN covers mainly power generation and all activities of power transmission, distribution through its subsidiaries. For setting retail electricity tariff, EVN has developed a tariff revision proposal, which it needs to submit to MOI, SPC and Government's office and finally approved by National Assembly. This tariff reflects subsidy from government and cross-subsidy for all customer classes.

CHAPTER 5

CONCLUDING REMARKS

MAJOR FINDINGS

One of the prominent features of the APEC member economies is the immense diversity measured in terms of the level of economic development, social and political systems, culture, climate and resource endowments. Accordingly, it is natural that there is a much variation between the energy pricing mechanisms of individual APEC member economies, ranging from market pricing to controlled pricing ones. APERC has endeavoured to derive policy implications of energy pricing practices for energy efficiency, the environment, and energy supply infrastructure in the APEC region. To this end, it conducted a survey into the existing energy pricing practices in the member economies with regard to energy price structure, related regulatory regimes, tax and subsidy, and so on. Also, it has been collecting data on energy prices so as to undertake an empirical analysis based on the gathered data set. The data collection aimed to cover four kinds of energy sources, namely, coal, petroleum products, natural gas and electricity across the twenty-one APEC member economies. The major findings in this study are summarised below.

The coal price consists of: mine mouth cost comprising capital cost, labour cost and royalty; transportation cost such as railway and port costs; producer profit margin; and various taxes and levies. As a decreasing factor to the coal price, subsidies are also found in some cases. Prices of domestically produced coal are determined by market mechanism in Australia, Canada, China and the United States. Market pricing also applies to imported coal for Japan, Korea and Chinese Taipei. These latter three economies were found to subsidise domestically produced coal, mainly for labour protection and national energy security reasons. As a reference price in the international coal trade, the Australian benchmark price for coal export to Japan prevails in the APEC region.

The price of petroleum products is made up of cost of crude oil procurement, refinery cost and margins, transportation costs, retailer margins, taxes and levies, and subsidies. While most economies adopt the market pricing mechanism, some economies, such as Brunei Darussalam, China, Indonesia and Viet Nam, are controlling the prices of petroleum products. Chinese Taipei has a specific plan to liberalise the market for petroleum products by 2000. The main reasons for the price regulation include the strategic importance of oil to the economy and social policy objectives like the support for low-income groups. The liberalization of export and import of petroleum products seems to be an important factor in supporting the operation of the market pricing mechanism. However, the introduction of the market pricing mechanism seems only feasible in a mature oil market and with an established investment environment.

As for natural gas, processing and transportation costs constitute a big portion of the end-user price. In order for natural gas to be used, large-scale investments need to be made in processing plants with long operating periods. Another important characteristic of natural gas is that it is transported via large-diameter pipelines or LNG ships and it requires a reticulated distribution network down to end-users, which also requires large-scale investment capital. As such, the terms and conditions of purchase and sales contract exert a great influence on the level of downstream natural gas prices. Also, the degree of supply infrastructure development affects the level and structure of end-user prices, which are also partly determined by load patterns. Many economies strongly regulate natural gas prices on the ground that the price regulation is a way of reducing purchase price and that there are areas of natural monopoly, especially in the transportation functions. All member economies adopt some form of price regulation, ranging from self-regulation by a state-owned company to light-handed regulation in the context of a general industrial policy. Natural gas price is determined by competition between suppliers in Australia, New Zealand, Chile and in some states of the United States. However, in most cases, the level of natural gas price is linked to competitive fuels like petroleum products. The natural gas sector is one of those where market reforms are actively taking place with more performance-based pricing schemes being introduced.

The electricity price is determined in a similar way to that of natural gas, in that the electricity industry shares similar industry structure and cost structure with its characteristic of a network industry requiring huge investments depending on load size and pattern. In the electricity industry, it seems that competition has been easier to introduce than in the natural gas industry at least at the production level, that is, power generation, because fuel procurement and plant dispatch are more flexible than production swings in the upstream natural gas market. Therefore, some economies such as the United States, Australia, New Zealand, and Chile have introduced a market pricing mechanism at the wholesale level and retail competition is being introduced. However, as in the natural gas sector, a minimal level of regulation exists in all member economies in the transportation function, namely transmission and distribution of electricity. And, the regulation itself seems to become more incentive-based. While the level of electricity price is affected more by the industry structure, ownership structure and the fuel mix in power generation, the structure of the price has been more dependent on the government's policy objectives like economic efficiency and other social policy obligation.

The data collection and the development of a standardised energy price database are rather incomplete compared with the initial plan and this has limited the depth of analysis. There are several reasons for this. The most important one, among others, is that, in many cases, there simply do not exist the data that are required to perform the analysis and fitting to the data base format. Also, some economies were reluctant to release data, especially, concerning tax and subsidy on energy price for the reason of confidentiality. These are, in a sense, reflection of the diversity of the APEC member economies. However, it is also true that transparency is required with respect to the pricing policy and the diverse elements of energy price, if the member economies are to collaborate to achieve a higher level of economic well-being in the APEC region.

FUTURE WORK

During the course of the study, some difficulties have been identified in performing a comprehensive and detailed analysis on the pricing practices of the four energy sources across the member economies. The most difficult part was, as expected, to collect price data on the basis of a standardised format. Some economies do not have a compiled data set at all for certain periods. Also, each member economy has its own energy pricing practice and the underlying reasons or policy needs are diverse. This makes it hard to compare the pricing practices across the member economies on the same ground and to derive policy implications.

Difficulties having been identified and the goal in our hands being to derive policy implications, the next step seems rather obvious. That is, some economisation is necessary between input and output. One alternative may be described as follows. It will mainly consist of two parts: the first is to focus on economies that are with relatively sufficient data availability and representative in terms of a variety of criteria, and to analyse the pricing practices of those economies in more depth; and the second is to develop a sample energy price data base for those economies for future expansion to cover more economies.

The alternative given above is an inductive approach to derive policy implications. It seems to be capable of overcoming the problem of too wide a scope of the project, although an inductive approach itself bears its own difficulties, in that it derives a general proposition from analysis of specific cases. This latter difficulty is related to the selection of representative economies in our study, and, accordingly, will demand much time and efforts during the selection process. Candidate criteria that may be employed in the selection process are, for example, such measurements as GDP per capita, energy-GDP ratio, energy consumption per capita, and infrastructure investment per capita. However, there ought to be some elements that have to be taken into account in the selection process but are hard to quantify. Some qualitative judgments by the author are unavoidable under these circumstances, while they leave room for arguments about justification for the selection results.

As regards the data base development, two issues are to be resolved. The first is concerned with who will maintain the database and with data sources. The coordinating agency of the APEC Expert Group on Energy Data and Analysis (EGEDA), the Energy Data and Modelling Center (EDMC), IEEJ, may maintain the database in close cooperation with APERC. Or APERC may do it by itself. Either way the focus should be on the maximum extent of accommodating analysis on energy prices and other related data in terms of data manipulation and consistency with the existing APEC Energy Database. As for the data source, efforts should be made to collect the most accurate official data from official sources. In this regard, if the EDMC, IEEJ were to do the job, it would need to collaborate with APERC from the designing stage of the database, and the EGEDA members might need to serve as the window of dada gathering. If APERC develops and maintains the database, APERC will do analysis based on the database and share the data and analytical results with others. However, in the latter case, database users will have to access the price data separately from the APEC Energy Database currently managed by the EDMC. Considering that a comprehensive database should be maintained at the level of an organization, it has also to be recognised that the high turnover ratio of the APERC staff may hamper continuous and stable maintenance of the database.

The second issue is about the usefulness of the database or the requirement that the database, if developed, should provide data in a way that is user-friendly and suitable for quantitative analyses. However, it will be very difficult for the data base to accommodate qualitative discrepancies embedded in the price data resulting from different pricing practices of each economy. Therefore, it is possible that the usefulness of the database is limited compared with the costs of its development and maintenance. This is an important problem for which a remedy must be developed over time both practically and theoretically.

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APPENDIX

APEC ENERGY PRICING DATABASE

OVERVIEW

The construction of a standardised APEC Energy Pricing Database was one of the key tasks assigned to APERC as part of the APEC Energy Pricing Practices project. The database aims to provide disaggregated energy prices for electricity, coal, oil and natural gas for all 21 APEC economies.

As an energy research centre, APERC's role has not been to collect energy pricing information, but instead to collate existing pricing data from various sources. Therefore the database utilises energy prices from official national statistics, domestic energy research institutions, energy corporations, international energy institutions and other organisations.

Appendix A introduces the APEC Energy Pricing Database describing the energy variables included in the database, the source of the pricing data, an assessment of the quality of the data, as well as future work needed to maintain and improve the database.

ENERGY PRICING DATA

The availability of energy pricing information varies widely between twenty-one APEC member economies reflecting the many different factors influencing each energy sector. These factors range from differing government policies influencing the operation of energy markets, through to the confidentiality claims of market participants.

The methodology used for collecting energy pricing information also varies between energy commodities and the particular economy. In most economies there is no centralised organisation for the collection of all energy pricing data

APEC ENERGY PRICING DATABASE VARIABLES

As specified in the project's Terms of Reference, the APEC Energy Pricing Database collates existing energy pricing data for coal, oil, natural gas and electricity in all twenty-one APEC economies. Table 40 and Table 41 illustrate the economies included in the database, and the database variables respectively.

Table 40 APEC Economies included in the APEC Pricing Database

APEC Economies		
Australia	Indonesia	Philippines
Brunei Darussalam	Japan	Papua New Guinea
Canada	Korea	Russia
Chile	Malaysia	Singapore
China	Mexico	Thailand
Chinese Taipei	New Zealand	United States of America
Hong Kong, China	Peru	Viet Nam

Table 41 Energy Types and Classifications in the APEC Energy Pricing Database

Energy	Commodity	Category
Oil	Crude Oil	
	Gasoline	Regular leaded Regular unleaded Premium leaded Premium unleaded Automotive diesel oil Industrial diesel oil
	Fuel Oil	Bunker – A Bunker – B Bunker – C High Sulfur Low Sulfur Light Unspecified
	Jet Oil	-
	Kerosene	-
	LPG	Butane LPG Propane LPG Unspecified
	Diesel Oil	-
Gas	Natural Gas	-
	City Gas	-
	LNG	-
Coal	Coal	Anthrasite Bituminous (Steaming) Sub-bituminous Lignite Briquette Coking Unspecified
Electricity	Electricity	-
	Heat	-

AVAILABILITY OF DATA

The energy pricing database has included seventeen out of twenty one APEC member economies, namely Australia, Brunei, Canada, Chile, Chinese Taipei, Indonesia, Japan, Korea, Malaysia, Mexico, New Zealand, Peru, the Philippines, Russia, Singapore, Thailand and the United States.

Most of the data is obtained from the government sources, except some economies, which are OECD countries, whose data come from IEA. Most of consumer price data is provided for gasoline, diesel oil, and electricity with various classifications. On the one hand, certain economies such as Korea, Singapore and Thailand has various classifications of particular types of fuel, that further clarification is required to adjust to the other economies' classification. On the other hand, sufficient numbers of fuel types are not available for some economies. The availability of data is illustrated in the attached matrix.

CONSUMER PRICE

As for gasoline, most of economies were moving from leaded gasoline to unleaded gasoline either for regular or premium gasoline during the period, as can be observed from the data. Most of the economies only have one type of diesel oil, except Australia, Chinese Taipei, Indonesia, Mexico, New Zealand, Singapore, and Thailand, which have two types in different classifications. Other types of energy that are mostly complete are fuel oil and electricity. The electricity data mostly has household and industry tariffs.

PRODUCER PRICE

In the producer price category, data is obtained only for Australia, Brunei, Indonesia, Japan, Korea, Russia, Thailand and the United States for limited types of energy. Australia, Indonesia and Korea, Russia and the United States have quite extensive data on coal, which is used for various purposes, mostly coking and steaming. Data for Brunei is available for six petroleum products, but unfortunately only covers the last two years. Data for Japan is available for a long period (1980-1998) for gasoline, kerosene and fuel oil. Data for Russia has been provided for six energy types including crude oil and a number of petroleum products.

IMPORT PRICE

In the import price category, the data has been collected for Australia, Brunei, Japan, Korea, Thailand and the United States.

TAX AND OTHER SURCHARGES

The data on tax and surcharges, which is essential, is rare and can only be obtained for Mexico, Thailand and the United States. As already deliberated, the availability of this data is often subject to confidentiality.

TIME HORIZON

The expected time horison for the data is 1980-1998. Most economies have complete data from 1980 to 1997 for consumer price, some economies even have it for 1998. However, incompleteness is still found in the rest of the economies, especially for producer and import price. Sometimes the records only cover the last one to three years.

OTHER FACTORS TO BE FURTHER CONSIDERED

In order to achieve the objectives of the study, it is necessary to complete the data requirement, while solving the problem of disparity in the data classification. It is also important to have related socio-economic data such as GDP and population. Such data for all APEC economies is available in APEC Energy Database, developed by the Energy Data and Modelling Center (EDMC) of the Institute of Energy Economics, Japan (IEEJ).

Table 42 Data Availability by Economy

Australia

	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Consumer Price		Premium leaded, Premium unleaded (1980-1997)	For Transport, Industry (1980-1997)		High sulphur, Light sulphur, for Industry, Household (1980-1997)		For Household , Industry (1980-1997)		For Household, Industry (1980-1997)	Coking, Steaming (1980-1997)
Producer Price										Coking, Steaming, for Industry (1980-1989), Power generation (1980-1991)

	Crude Oil	LNG	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Import Price	(1980-1997)										

Brunei

	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Consumer Price		Premium leaded, Regular leaded, Premium unleaded (1997-1998)	(1997-1998)	(1997-1998)				Butane (1997-1998)	Household, Industry, Commercial (1960-1998)	
Producer Price		Premium leaded, Regular leaded, Premium unleaded (1997-1998)	(1997-1998)	(1997-1998)	Bunker-A (1980-1998)	(1997-1998)		Butane (1997-1998)		

	Crude Oil	LNG	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Imp											

		Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
					(1997-1998)			(1997-1998)			
Canada		**Crude Oil**	**Gasoline**	**Diesel Oil**	**Kerosene**	**FO**	**Jet Oil**	**Natural Gas**	**LPG**	**Electricity**	**Coal**
	Consumer Price		Regular unleaded (1978-1997), Premium unleaded (1990-1997)	(1981-1997)		High sulphur [LCR/tonne], Light sulphur [LCR/litre], for Industry, Household (1978-1996)		For Industry, Household (1978-1997), Power (1978-1992)		For Industry, Household (1978-1994)	Steaming, Coking for Industry (1978-1989), Power (1978-1984)
Chile		**Crude Oil**	**Gasoline**	**Diesel Oil**	**Kerosene**	**FO**	**Jet Oil**	**Natural Gas**	**LPG**	**Electricity**	**Coal**
	Consumer Price		Regular leaded, Extra, Regular unleaded (1991-1996)	(1991-1996)	(1991-1996)	(1991-1996)	(1991-1996)	(1991-1996)	(1991-1996)	Household, Industry, Commercial (1991-1996)	Steaming (1991-1996)
China		**Crude Oil**	**Gasoline**	**Diesel Oil**	**Kerosene**	**FO**	**Jet Oil**	**Natural Gas**	**LPG**	**Electricity**	**Coal**
	Consumer Price				(1989-1993, 1997-1998)			Household (1989-1993, 1997-1999)	Household (1989-1993, 1996-1999)	Household (1989-1999)	Household (1989-1993, 1997-1999)
	Producer Price		No. 90 and no. 93, leaded and unleaded (1997-1999)	No. 0, no. 10 and no. 20, (1997-1999)		HFO, decompress (1989-1999)		By industry (1997-1999)		(1997-1999)	Coking, steaming (1989-1999)
Chinese Taipei		**Crude Oil**	**Gasoline**	**Diesel Oil**	**Kerosene**	**FO**	**Jet Oil**	**Natural Gas**	**LPG**	**Electricity**	**Coal**
	Consumer Price		Premium leaded, Regular leaded (1987-1997)	Premium diesel, Regular diesel (1987-1997)	(1987-1997)	(1987-1997)		For Industry, Household (1985-1997)	(1987-1997)		Various calorific value (1993-1997)
Indonesia		**Crude Oil**	**Gasoline**	**Diesel Oil**	**Kerosene**	**FO**	**Jet Oil**	**Natural Gas**	**LPG**	**Electricity**	**Coal**
	Consumer Price		Premium leaded, Regular leaded (1980-1998)	Industrial diesel oil, Automotive diesel oil (1980-1998)	(1980-1998)	(1980-1998)	(1980-1998)		(1980-1998)		(1998)
	Producer Price							(1983-1998)			Steaming, Coking (1990-1994)

Country	Price	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Japan	Consumer Price										
Japan	Producer Price		(1980-1998)		(1980-1998)	High sulphur for electricity and ship (1980-1998)					

Country	Price	Crude Oil	LNG	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Japan	Import Price	(1980-1997)	(1980-1997)				High sulphur (1980-1997)			(1980-1997)		

Country	Price	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Korea	Consumer Price		Premium leaded, Regular leaded, Regular unleaded (1981-1996)	(1981-1997)	(1981-1997)	High sulphur for Bunker-A, Bunker-B, Bunker-C (1981-1997)	(1981-1983)	City gas for Household, Commercial, Industry (1987-1997)	Propane, Butane for General Use, City gas (1981-1997)	For Average, Lighting, Power (1980-1997)	Briquette (1980-1988)
Korea	Producer Price										Anthracite, Briquette (1980-1997)

Country	Price	Crude Oil	LNG	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Korea	Import Price	(1980-1997)							(1986-1997)			

Country	Price	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Malaysia	Consumer Price		Regular leaded (1984-1998), Regular unleaded (1993-1998)	(1984-1998)	(1984-1998)					(1984-1998)	

Country	Price	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Mexico	Consumer Price		Regular leaded (1985-1997), Regular unleaded (1984-1997), Tax	For Industry, Household (1980-1997), Tax		High sulphur, Light sulphur, for Industry, Power generation (1980-1997), Tax		For Industry, Power generation (1980-1997), Tax		For Industry, Household (1984-1997), Tax (1988-1997), Tax	Steaming for Power generation (1980-1997), Tax

Economy	Price	Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
New Zealand	Consumer Price		Premium leaded (1980-1995), Premium unleaded (1997)	For Transport , Industry (1980-1997)		High sulphur, Light sulphur for Industry, Household (1980-1997)		For Household , Industry (1980-1997)		For Household, Industry (1980-1997), Tax for Household (1987-1997)	For Industry (1981-1984), Power generation (1980-1984)
Peru	Consumer Price									For Household, Industry, Commercial (1980-1998)	
Philippines	Consumer Price		Regular leaded (1990-1998), Premium leaded (1990-1998), Premium unleaded (1994-1998)	(1990-1998)	(1990-1998)	(1990-1998)	(1990-1998)		(1990-1998)	For Household, Industry, Commercial (1991-1998)	
Russia	Consumer Price	(1995-1997)	Regular leaded (1995-1997)	(1995-1997)		(1997)		(1997)		(1991-1997)	(1995-1997)
Russia	Producer Price	(1991-1997)	Regular leaded (1991-1997)	(1991-1997)		(1991-1997)		(1991-1997)			(1991-1997)
Singapore	Consumer Price		Three types of Unleaded (1996-1998)	1%S, 0.5%S (1996-1998)	(1996-1998)	Various types for Transport (1996-1998)					

		Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Thailand	Consumer Price		Regular leaded (1987-1992), Premium leaded (1987-1996), Regular unleaded (1993-1996), Premium unleaded (1991-1996), Other surcharge	LSD, HSD (1992-1997)	(1992-1997)	Types 600, 1500, 1500 (2%S), 2000, 2500, 2501, 2502 (1992-1997)		For Industry (1985-1998)	For Transport (1992-1997)	For Industry, Household, Commercial, Agriculture, Others (1981-1997)	
Thailand	Producer Price		Regular leaded (1991-1997), Regular unleaded (1993-1997), Premium unleaded (1992-1997), Tax	HSD 1%, HSD 0.5%, HSD 0.25%, LSD (1992-1997) by turns	(1992-1997), Tax	(1992-1997), Tax		(1985-1998)	(1992-1997), Tax, Other surcharges		

		Crude Oil	LNG	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
Thailand	Import Price	(1986-1998)		Regular leaded (1991-1997), Regular unleaded (1993-1997), Premium unleaded (1992-1997), Tax, some years missing	Sulphur 1%, Sulphur 0.5%, Sulphur 0.25%, LSD (1991-1993)	(1991-1997)	(1991-1997)			(1991-1997)	(1991-1997)	

		Crude Oil	Gasoline	Diesel Oil	Kerosene	FO	Jet Oil	Natural Gas	LPG	Electricity	Coal
USA	Consumer Price		Premium leaded (1980-1983), Premium unleaded (1983-1997) + Tax, Regular unleaded 98 (1980-1997), Tax	Automotive (1980-1997), Tax		High sulphur, Light sulphur for Industry, Household, Power generation (1980-1997)		For Household, Industry, Power generation (1980-1997)		For Household, Industry (1980-1997)	Coking, Steaming for Industry, Power generation (1980-1997)
USA	Producer Price										For Steaming, Coking (1980-1997)